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	:	

CONSUMER PROTECTION AND SAFETY DIVISION
CALIFORNIA PUBLIC UTILITIES COMMISSION

REBUTTAL TESTIMONY OF GARY HARPSTER

Order Instituting Investigation on the Commission's own Motion into the Operations and Practices of Pacific Gas and Electric Company to Determine Violations of Public Utilities Code Section 451, General Order 112, and Other Applicable Standards, Laws, Rules and Regulations in Connection with the San Bruno Explosion and Fire on September 9, 2010.

I.12-01-007

San Francisco, California
August 20, 2012

Rebuttal Testimony of Gary Harpster
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Rebuttal Testimony of
Gary C. Harpster

Section 1
Introduction

Qualifications

Q. Please state your name, occupation and business address.

A. My name is Gary Harpster. I am a senior manager with Overland Consulting (Overland), a public utility regulatory consulting firm. Overland's offices are located at 11551 Ash Street, Suite 215, Leawood, Kansas, 66211.

Q. Please briefly describe your education background and professional experience.

A. I am an accountant and auditor with 33 years of public utility regulatory consulting experience with Overland and its predecessor firms. During that time I have participated in a wide variety of regulatory consulting projects involving electric, natural gas and telecommunications utilities. My educational background and professional experience are described in more detail on Attachment A.

Q. Did you participate in the focused audit of PG&E's Gas Transmission Pipeline Safety-Related Expenditures conducted by Overland for the CPUC's Consumer Protection and Safety Division (CPSD)?

A. Yes. I was the project manager for that audit.

Q. Referring to the report issued by Overland on December 30, 2011 titled "Focused Audit of Pacific Gas & Electric Gas Transmission Pipeline Safety-Related Expenditures" (The Overland Report), are you sponsoring that report in this proceeding?

A. Yes.

Scope and Organization

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the responsive testimony of Matthew P. O'Loughlin submitted by PG&E on June 25, 2012.[1]

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[1] Mr. O'Loughlin's testimony is contained in a series of Exhibits denoted Exhibit_ (MPO-1) to Exhibit_(MPO-7)

Q. What was the scope of Mr. O'Loughlin's responsive testimony?

A. Mr. O'Loughlin addresses portions of Chapters 2 through 5 of the Overland Report. PG&E did not submit any responsive testimony addressing Chapters 6 through 9 of the Overland report.[2]

Q. How is your testimony organized?

A. My testimony is organized into the following sections:

Table 1-1 Rebuttal Testimony of Gary Harpster Sections	
Section	Title
1	Introduction
2	Summary
3	Overland Revised Tables
4	1997 to 2002 Adopted Functional O&M Expenses
5	1997 to 2002 Adopted Capital Expenditures
6	2003 Adopted Functional O&M Expenses
7	2003 Adopted Capital Expenditures
8	2005 to 2007 Adopted Capital Expenditures
9	2008 to 2010 Adopted Functional O&M Expenses
10	2008 to 2010 Adopted Capital Expenditures
11	Rate Base
12	Adopted Revenue Requirements
13	Actual Revenues
14	Actual Functional O&M Expenses
15	Customer Accounts and Sales Expenses
16	Other Actual Expense Differences
17	Actual Return On Equity - Income Tax Normalization Policy
18	Surplus Revenues
19	PG&E's "At-Risk" Storage Business
20	PG&E's Total Company Return On Equity

Q. The titles of several sections include the term "Functional O&M." What is that?

A. O&M expenses include storage, transmission, distribution, customer accounts, sales and A&G expenses. Overland's comparisons of adopted and actual O&M were limited to storage, transmission and distribution expenses applicable to GT&S operations.

[2] Chapter 1 is the Executive Summary.

Overland's report uses the term "functional O&M" in the section titles to indicate that the O&M expenses addressed in those sections exclude customer accounts, sales and A&G expenses.

Q. Why did Overland exclude customer accounts, sales and A&G expenses from its comparison of adopted and actual O&M?

A. Overland excluded those expenses from its O&M comparison because they do not include transmission safety-related O&M. The purpose of the comparison is to provide insight into PG&E's funding of safety-related costs. A comparison of actual and adopted customer accounts, sales and A&G expenses does not provide any meaningful insight into the adequacy of transmission safety funding.[3]

[3] Overland Report page 3-1, footnote 1

Section 2
Summary

Q. Please provide a summary of your rebuttal testimony.

A. Overland accepted several changes recommended in Mr. O'Loughlin's testimony. Those changes did not significantly impact Overland's results or the findings and conclusions stated in the Overland Report.

Overland's revised functional O&M comparison shows that PG&E underspent by $40 million over the 14-year study period. Mr. O'Loughlin claims PG&E overspent on functional O&M by $19 over the same period. The difference is explained by: (1) a fundamental disagreement about the correct basis for determining adopted O&M expenses in 2003 and 2008 to 2010; and (2) four errors made by Mr. O'Loughlin. His largest error was including $22 million in San Bruno Incident response costs in actual 2010 O&M. Those costs are the direct consequence of multiple violations of CPUC safety rules and should be excluded from the O&M comparison for that reason.

Overland's revised capital expenditures comparison shows that PG&E underspent by $117 million over the study period. Mr. O'Loughlin claims PG&E overspent by $262 million over the same period. Mr. O'Loughlin claims PG&E overspent by $275 million in just three years, 2008 to 2010. He claims that PG&E spent 82 percent more than its adopted capital expenditures in 2008 to 2010. That claim is not credible, as demonstrated in Section 10. Mr. O'Loughlin's implausible claims of massive overspending in 2008 to 2010 demonstrate the fundamental error in his approach during those years.

Overland's revised revenue comparison shows that actual revenues exceeded adopted revenue requirements by $244 million over the period 1999 to 2010. Mr. O'Loughlin claims actual revenues exceeded adopted by $515.5 million over the same period. Mr. O'Loughlin's comparison is invalid because his adopted revenue requirements are incorrect. Mr. O'Loughlin excluded $236 million from his adopted revenue requirements based on his theory that approximately half of the Line 401 revenue requirement was excluded from the GA I Settlement. That theory is wrong for the reasons stated in Section 4.

Overland and Mr. O'Loughlin both agree that GT&S operations were very profitable. Overland's revised calculations show that the actual GT&S return on equity averaged 14.3 percent over the review period. Mr. O'Loughlin concludes the actual ROE averaged 14.6 percent.

Overland's revised calculations show $435 million in surplus revenues. Mr. O'Loughlin claims the surplus revenues totaled $479.5 million during the same period.

Mr. O'Loughlin uses his erroneous comparison of adopted and actual revenues to explain away the surplus revenues and avoid admitting that actual O&M and capital expenditures were lower than adopted. After Mr. O'Loughlin's revenue comparison is corrected, it only explains $244 million of his $479.5 million in surplus revenues. Mr. O'Loughlin's comparisons of actual and adopted revenues and expenses do not come close to explaining his finding of $479.5 million in surplus revenue. The unexplained gap demonstrates the inaccuracy of his claims of over-spending.

Mr. O'Loughlin places a great deal of emphasis on the fact that PG&E's storage business produced a significant portion of the surplus revenues. Distinguishing between PG&E's storage profits and transmission profits is largely pointless in this case. Almost all of the storage profits cited by Mr. O'Loughlin were produced by parking and lending services. Those services make extensive use of PG&E's transmission system.

Approximately 88 percent of the total adopted storage revenue requirement was charged to transmission customers through core storage and transmission balancing charges during the study period. Since the same customers pay for almost all of the costs of the transmission and storage functions, distinguishing between storage and transmission profits is not particularly meaningful.

Mr. O'Loughlin's misguided attempts to distinguish between storage and transmission profits do not change the fact that PG&E's GT&S operations were highly profitable during the review period.

Section 3
Overland Revised Tables

Q. Mr. O'Loughlin recommended several changes to Overland's analysis. Do you agree with any of those changes?

A. Yes. I accepted several of the changes proposed by Mr. O'Loughlin. In addition, Mr. O'Loughlin's testimony prompted a couple of other changes to Overland's results. I have revised the following tables contained in the Overland report to reflect those changes.

Table 3-1
List of Overland Revised Tables
Prepared For Rebuttal Testimony

Table	Title
3-1	Comparison of Actual and Adopted Functional O&M Expenses
4-1	Comparison of Actual and Adopted Capital Expenditures
5-1	Comparison of Actual and Adopted Return on Equity
5-2	Surplus Revenue
5-3	Comparison of Actual and Adopted Revenues
5-4	Comparison of Actual and Adopted GT&S Rate Base

The revised tables listed above are the summary tables from the Overland Report. They show the impact of the changes on a total GT&S basis. The summary tables are supported by more detailed tables within the Overland report. I have not included revised versions of those more detailed tables in my rebuttal testimony.

Q. Do the revisions have a significant impact on Overland's results?

A. No.

Q. Please describe the revisions that were made to Table 3-1.

A. Revised Table 3-1 is shown below.

Table 3-2 Revised Overland Table 3-1 Comparison of Actual and Adopted Functional O&M Expenses 1997 to 2010 Dollars in Thousands			
Year	Actual	Adopted	Difference
1997	56,936	58,253	(1,317)
1998	64,160	59,732	4,428
1999	56,348	61,250	(4,902)
2000	59,378	62,803	(3,425)
2001	66,815	64,398	2,417
2002	64,189	66,034	(1,845)
2003	65,245	76,009	(10,764)
2004	70,749	78,762	(8,013)
2005	74,819	76,962	(2,143)
2006	75,615	78,416	(2,801)
2007	77,854	79,898	(2,044)
2008	81,991	85,498	(3,507)
2009	86,902	87,101	(199)
2010	80,103	85,916	(5,813)
Total	981,104	1,021,032	(39,928)
Source: Overland Analysis			

After the revisions, PG&E's actual functional O&M expenses are $39.9 million less than adopted over the study period. That compares to a spending shortfall of $39.2 million shown on Table 3-1 in the Overland Report.

Overland made one revision to adopted functional O&M and one revision to actual O&M. The revision to adopted O&M accepted Mr. O'Loughlin's slightly lower escalation factor for 2006 and 2007. The revision to actual O&M accepted Mr. O'Loughlin's adjustment to exclude local storage maintenance expenses from actual O&M.[4]

Q. Please describe revised Table 4-1.

A. Revised Table 4-1 is shown below.

[4] Account 843 is a local storage maintenance account

Table 3-3 Revised Overland Table 4-1 Comparison of Actual and Adopted Capital Expenditures 1997 to 2010 Dollars in Thousands			
Year	Actual	Adopted	Difference
1997	61,630	75,200	(13,570)
1998	39,307	75,200	(35,893)
1999	31,664	75,200	(43,536)
2000	66,431	75,200	(8,769)
2001	97,714	75,200	22,514
2002	132,566	75,200	57,366
2003	89,030	99,908	(10,878)
2004	81,199	142,100	(60,901)
2005	119,176	111,289	7,887
2006	129,365	113,392	15,973
2007	158,330	153,045	5,285
2008	216,751	221,970	(5,219)
2009	200,319	249,969	(49,650)
2010	192,993	190,260	2,733
Total	1,616,475	1,733,133	(116,658)
Source: Overland Analysis			

After the revisions, PG&E's actual capital expenditures are $116.7 million lower than adopted over the study period. That compares with under-spending of $95.4 million shown on Table 4-1 in the Overland Report.

Overland made four changes to its adopted capital expenditures. All four changes were recommended by Mr. O'Loughlin. The four changes are listed below.

- Include Common Plant expenditures in adopted capital expenditures during 1997 to 2002;
- Modify the treatment of NOx capital expenditures in Overland's GA I period capital expenditures imputation model to directly account for the capital expenditures amounts shown in the GA I Settlement workpapers.
- Escalate Overland's 2004 adopted capital expenditures from 2001 dollars to 2004 dollars.
- Use Mr. O'Loughlin's slightly lower escalation rate to calculate 2006 adopted capital expenditures.

Q. Please describe revised Table 5-3.

A. Revised Table 5-3 is shown below.

Table 3-4 Revised Overland Table 5-3 Comparison of Actual and Adopted Revenues 1999 to 2010 Dollars in Thousands			
Year	Actual	Adopted	Difference
1999	379,090	418,008	(38,918)
2000	434,786	422,432	12,354
2001	518,159	426,124	92,035
2002	453,017	429,992	23,025
2003	378,690	453,017	(74,327)
2004	428,893	438,834	(9,941)
2005	448,007	429,276	18,731
2006	476,716	437,393	39,323
2007	490,691	445,667	45,024
2008	498,851	449,415	49,436
2009	515,034	461,819	53,215
2010	508,324	474,266	34,058
Total	5,530,258	5,286,243	244,015
Source: Overland Analysis			

PG&E's actual GT&S revenues exceeded its adopted revenue requirements by $244.0 million over the study period. That compares to an actual revenue excess of $223.7 million shown on Table 5-3 in the Overland Report.

Overland made two changes to actual revenues. Both of those changes were recommended by Mr. O'Loughlin. The first change reduces revenues to correct a double counting of customer access charge revenues in 2004. The second change increases actual revenues to include storage carrying charge revenues.[5] That change increased revenues by $33.5 million over the study period. However, the increase in revenues was more than offset by a corresponding $52 million increase in actual storage carrying charge expenses.[6] The expense increase was also recommended by Mr. O'Loughlin.

Q. Please describe revised Tables 5-1 and 5-2.

A. Revised Tables 5-1 is shown below.

[5] The increase in 2002 actual revenues also resulted in a $4.4 million increase in Overland's 2003 adopted revenues, because 2003 adopted revenues are based on 2002 actual revenues for the reasons explained in Section 12.

[6] The storage carrying cost expenses are not included in functional O&M. They are addressed in Section 16.

Table 3-5 Revised Overland Table 5-1 Comparison of Actual and Adopted Return on Equity GT&S Operations 1999 to 2010			
Year	Actual	Adopted	Difference
1999	10.8	10.6	0.2
2000	16.0	11.2	4.8
2001	23.5	11.2	12.3
2002	15.7	11.2	4.5
2003	8.2	11.2	(3.0)
2004	12.2	11.2	1.0
2005	13.3	11.2	2.1
2006	14.1	11.4	2.7
2007	15.3	11.4	3.9
2008	14.7	11.4	3.3
2009	14.3	11.4	2.9
2010	13.3	11.4	1.9
Source: Overland Analysis			

The average GT&S actual return on equity is 14.3 percent over the study period. That compares to an average of 14.2 percent shown on Table 5-1 in the Overland Report.

Revised Table 5-2 is shown below.

Table 3-6 Revised Overland Table 5-2 Surplus Revenue 1999 to 2010 Dollars in Thousands	
Year	Actual
1999	2,544
2000	51,587
2001	132,178
2002	51,353
2003	(34,865)
2004	12,110
2005	26,061
2006	34,319
2007	50,344
2008	43,543
2009	39,247
2010	26,820
Total	435,241
Source: Overland Analysis	

PG&E's revenues exceeded the amount needed to earn its authorized return on equity by $435.2 million over the study period. That compares to surplus revenues of $429.8 million shown on Table 5-2 of the Overland Report.

Q. What caused the changes in surplus revenue?

A. The following table provides a reconciliation between the surplus revenues shown in the Overland Report and the revised amounts.

Table 3-7
Surplus Revenue Reconciliation
Overland Report Table 5-2 Reconciled to Revised Table 5-2
1999 to 2010
Dollars in Thousands

Description	Amount
Surplus Revenues Per Overland Report Table 5-2	429,841
Include Storage Carrying Charge Expenses and Revenues	(18,528)
Eliminate 2004 Customer Access Charge Double Count	(8,680)
Remove Local Storage Maintenance From O&M Expenses	764
Correct 2010 A&G Expenses	(2,000)
Revise Customer Accounts and Sales Expenses	25,147
Include 1981 in Normalized Vintages For Deferred Tax	8,343
CCFT Federal Deduction Timing Difference	354
Revised Surplus Revenues	435,241

Source: Overland Analysis

The first three reconciling items reflect changes to actual revenues and expenses recommended by Mr. O'Loughlin. The 2010 A&G reconciling item corrects a data entry error made by Overland.

The reconciling item for Customer Accounts and Sales Expenses has two components. The first component adjusts total Customer Accounts and Sales Expenses to agree with the source used by Mr. O'Loughlin for those expenses. The second component removes Account 912, Sales Expenses, from actual expenses during 1999 to 2002. The Sales Expense adjustment is explained in Section 15.

The deferred income tax adjustment corrects an error made by Overland. As explained in Section 17, Overland's actual income tax expenses include an adjustment to reflect the Commission's income tax normalization policies. The adjustment reflects flow-through treatment for plant vintages installed prior to 1981. Overland's original calculations provided flow-through treatment to vintages installed prior to 1982. The reconciling item corrects the cut-off date for flow-through treatment.

The CCFT Federal Deduction Timing Difference arises from the mechanics of the reconciliation and does not reflect a change in Overland's Report. The reconciling item accounts for the difference between statutory tax rates and effective tax rates caused by the fact that the federal deduction for state income tax expenses taken in the current year reflects the prior year's tax liability. The reconciliation item is actually a revision of the amounts shown for all of the other reconciling items to reflect the timing of their impact on state income tax expense.

Q. You removed Account 912, Sales Expenses, from actual expenses in 1999 to 2002. Was that revision prompted by Mr. O'Loughlin's testimony?

A. Yes. Overland's comparison of adopted and actual functional O&M expenses does not include Customer Accounts and Sales Expenses. Mr. O'Loughlin included those costs in his primary O&M comparison. Mr. O'Loughlin's treatment of Sales Expenses caused large differences between his actual and adopted O&M expenses during the GA I Period. While researching those differences, Overland discovered that Account 912 should be excluded from the actual expenses used to calculate 1997 to 2002 surplus revenues.[7]

Q. Please describe revised Table 5-4.

A. Revised Table 5-4 is shown below.

Table 3-8
Revised Overland Table 5-4
Comparison of Actual and Adopted GT&S Rate Base
1998 to 2010
Dollars in Thousands

Year	Actual	Adopted	Difference
1998	1,485,850	1,461,088	24,762
1999	1,392,221	1,463,144	(70,923)
2000	1,332,073	1,455,993	(123,920)
2001	1,333,148	1,449,051	(115,903)
2002	1,422,055	1,442,746	(20,691)
2003	1,444,565	1,460,241	(15,676)
2004	1,435,257	1,452,044	(16,787)
2005	1,425,855	1,454,012	(28,157)
2006	1,446,459	1,481,493	(35,034)
2007	1,466,990	1,509,493	(42,503)
2008	1,502,151	1,549,838	(47,687)
2009	1,533,565	1,666,821	(133,256)
2010	1,605,478	1,789,983	(184,505)

Source: Actual is OC-140 and OC-83, Adopted is Overland Analysis

[7] The calculations of the GT&S actual ROE and surplus revenues include all of GT&S's expenses, not just functional O&M. The revision to actual expenses also impacts the actual ROE for 1999 to 2002 reported on Table 5-1.

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PG&E's actual rate base averaged $62 million less than its adopted rate base over the study period. That difference is slightly lower than the average of $67 million shown on page 5-6 of the Overland Report.

Overland made two revisions to its adopted rate base. Both revisions were recommended by Mr. O'Loughlin. The first revision reduced 1997 to 2002 adopted rate base to reflected the treatment of NOx capital expenditures recommended by Mr. O'Loughlin. The second revision reduced 2006 and 2007 adopted rate base to reflect the slightly lower escalation factor recommended by Mr. O'Loughlin.

Q. Do the revisions discussed in this Section have a significant impact on the findings and conclusions stated in Overland's Report?

A. No.

Remaining Differences in Adopted Amounts

Q. Have you prepared tables comparing Overland's revised adopted functional O&M to the adopted functional O&M amounts recommended by Mr. O'Loughlin?

A. Yes. With two exceptions, Overland and Mr. O'Loughlin agree on the recorded functional O&M amounts shown in Overland's revised Table 3-1.[8] The remaining functional O&M issues raised by Mr. O'Loughlin relate to adopted amounts.

The following table compares the adopted functional O&M amounts recommended by Overland to the adopted functional O&M amounts recommended by Mr. O'Loughlin.

[8] The two exceptions are San Bruno Incident response costs and compressor station fuel costs. Those differences are explained in Section 14.

Table 3-9 Comparison of Adopted Functional O&M Overland Revised Compared to O'Loughlin 1997 to 2010 Dollars in Thousands			
Year	Overland	O'Loughlin	Difference
1997	58,253	55,200	3,053
1998	59,732	56,800	2,932
1999	61,250	58,400	2,850
2000	62,803	59,900	2,903
2001	64,398	61,500	2,898
2002	66,034	63,200	2,834
2003	76,009	63,200	12,809
2004	78,762	78,800	(38)
2005	76,962	77,000	(38)
2006	78,416	78,400	16
2007	79,898	79,900	(2)
2008	85,498	80,400	5,098
2009	87,101	80,500	6,601
2010	85,916	80,600	5,316
Total	1,021,032	973,800	47,232
Source: Overland Revised Table 3-1 and Exhibit__(MPO-1), page 39			

Overland's revised adopted functional O&M expenses are $47.2 million higher than Mr. O'Loughlin's adopted amounts.

Q. Have you prepared a similar table for adopted capital expenditures?

A. Yes. Overland and Mr. O'Loughlin agree on the actual recorded capital expenditures amounts included in the capital expenditures comparison. The remaining capital expenditures issues raised by Mr. O'Loughlin are solely related to imputed adopted amounts.

The following table compares the adopted capital expenditures recommended by Overland and Mr. O'Loughlin.

Table 3-10 Comparison of Adopted Capital Expenditures Overland Revised Compared to O'Loughlin 1997 to 2010 Dollars in Thousands			
Year	Overland	O'Loughlin	Difference
1997	75,200	43,430	31,770
1998	75,200	101,056	(25,856)
1999	75,200	90,916	(15,716)
2000	75,200	84,828	(9,628)
2001	75,200	89,594	(14,394)
2002	75,200	75,200	0
2003	99,908	56,245	43,663
2004	142,100	142,146	(46)
2005	111,289	113,669	(2,380)
2006	113,392	115,731	(2,339)
2007	153,045	106,853	46,192
2008	221,970	89,673	132,297
2009	249,969	158,203	91,766
2010	190,260	87,408	102,852
Total	1,733,133	1,354,952	378,181
Source: Overland Revised Table 4-1 and MPO Workpapers 134 to 137			

Mr. O'Loughlin's adopted capital expenditures are $378 million lower than Overland's adopted amounts. The largest differences occur in 2008 to 2010.

Section 4

1997 to 2002 Adopted Functional O&M Expenses

Q. What issues account for the differences in adopted functional O&M during the GA I period?

A. The following table shows the differences by issue.

Table 4-1
Gas Accord I Period
Imputed Adopted Functional O&M
Overland Compared to O'Loughlin
Dollars in Thousands

Year	Adopted O&M Per Overland	Line 401 Phase-In	1997 Escalation	Other	Adopted O&M Per O'Loughlin
1997	58,253	(1,590)	(1,358)	(57)	55,248
1998	59,732	(1,485)	(1,392)	(63)	56,792
1999	61,250	(1,371)	(1,427)	(71)	58,381
2000	62,803	(1,332)	(1,463)	(74)	59,934
2001	64,398	(1,289)	(1,499)	(79)	61,531
2002	66,034	(1,242)	(1,537)	(84)	63,171
Total	372,470	(8,309)	(8,676)	(428)	355,057

Sources: Overland Adopted is Revised Overland Table 3-1; O'Loughlin Adopted is MPO Workpaper page 24.

Line 401 Phase-In

Q. Mr. O'Loughlin claims the revenue requirements adopted in the GA I settlement excluded roughly half of the Line 401 revenue requirement. Do you agree with that position?

A. No. The GA I Settlement unbundled backbone transmission rates by transmission path. The GA I Settlement excluded a portion of the Line 401 revenue requirement from the rates for one of those paths, while fully including the entire Line 401 revenue requirement in the rates for three other paths. The entire Line 401 revenue requirement was used to calculate several rates adopted in the GA I settlement.

Q. Does the Line 401 phase-in issue raised by Mr. O'Loughlin have any impact on the comparison of adopted and actual capital expenditures?

A. No. The issue does not have any impact on adopted or actual capital expenditures.

Q. Does the Line 401 phase-in issue have a significant impact on the comparison of adopted and actual O&M?

A. The issue has a relatively small impact on the O&M comparison. The issue does not impact actual O&M. If Mr. O'Loughlin's position is accepted, the issue would reduce adopted O&M by a cumulative total of $8.3 million over the GA I period, as shown below.[9]

Table 4-2
Impact of Adopting O'Loughlin Line 401 Phase-In Position
On GA I Adopted O&M Expenses
1997 to 2002
Dollars in Thousands

Year	Overland Adopted Line 401 O&M	Excluded Percent Per O'Loughlin	Reduction to Adopted O&M
1997	2,565	62	1,590
1998	2,652	56	1.485
1999	2,742	50	1,371
2000	2,834	47	1,332
2001	2,930	44	1,289
2002	3,029	41	1,242
Total	16,752	50	8,309

Source: Overland Workpapers 3-13 to 3-18 and Exhibit ___ (MPO-3), page 6.

Q. Does the Line 401 phase-in issue have any impact on the determination of the actual return-on-equity (ROE) earned by GT&S operations?

A. No. The issue has no impact on the actual investment, expense or revenue amounts used to determine the GT&S actual return.

Q. What is the primary impact of the Line 401 phase-in issue?

A. If adopted, the Line 401 phase-in issue would have a significant impact on the comparison of adopted and actual revenues shown on Table 5-3 of the Overland Report. Specifically, adopting Mr. O'Loughlin's position would significantly reduce the adopted revenue requirements for the GA I period and 2003.[10] That impact is shown below.

[9] The impact of this issue on adopted O&M is not affected by the 1997 O&M escalation issue because the GA I Settlement workpapers included a separate forecast of Line 401 revenue requirements.

[10] Actual revenues would not change

Table 4-3 Impact of Adopting O'Loughlin Line 401 Phase-In Position On GA I Adopted Revenue Requirements 1999 to 2003 Dollars in Thousands			
Year	O'Loughlin Adopted Line 401 Revenue Requirement	Excluded Percent Per O'Loughlin	Reduction to Adopted Revenue
1999	113,032	50	56,307
2000	109,363	47	51,117
2001	105,674	44	46,143
2002	101,967	41	41,389
2003	101,967	41	41,389
Total	532,003	44	236,345
Source: MPO workpaper page 95			

The impact of the Line 401 phase-in issue on Mr. O'Loughlin's adopted revenue requirements is discussed in more detail in Section 12. The Line 401 phase-in issue also impacts the comparison of adopted and actual rate base as discussed in Section 11.

Q. Please describe the backbone transmission rates adopted in the GA I Settlement.

A. The GA I settlement provided for separate backbone transmission rates for the following transmission paths.[11]

[11] The names assigned to the paths have changed over time. The table shows the names used in the GA I Settlement and the short-hand titles used in the remainder of my testimony. The short-hand titles reflect the path names currently used in GT&S rate cases. The short-hand titles are used in this testimony to improve readability.

Table 4-4 Backbone Transmission Paths	
GA I Title	Shorthand Title
Malin to On-System for the Core	Redwood core
Malin to On-System	Redwood noncore
Malin to Off-system	Redwood off-system
G-XF Firm Service	G-XF
California Production and Storage to On-System	Silverado on-system
California Production, Storage, Market Center/Hub Services and On-System Delivery Points to Off-System	Silverado off-system
Topock to Off-System	Baja off-system
Topock to On-System	Baja on-system
Source: GA I Settlement, page 10	

On-system and off-system refer to delivery points. Delivery points in PG&E's service territory are referred to as "on-system." Core and noncore refer to two different types of on-system customers. All other delivery points are referred to as off-system. Most of the off-system deliveries occur in Southern California.

The Redwood backbone transmission path extends from the California/Oregon border at Malin to the San Francisco Bay Area. The Redwood path is used to deliver Canadian gas to on-system customers in the Bay Area and to off-system customers in Southern California. The G-XF path consists of the pre-existing firm transportation contracts for Line 401. Those contracts generally provided for the transport of gas from Malin to Southern California over Line 401. The Silverado Path is used to transport gas from California gas fields to on-system and off-system delivery points. The Silverado path is also used to transport gas between storage facilities in PG&E's service territory and on-system and off-system delivery points. The Baja path extends from the California/Arizona border at Topock to the San Francisco Bay area.

Q. Which paths included Line 401?

A. Line 401 costs were fully incorporated into the approved rates for the following paths: (1) Redwood off-system; (2) Silverado off-system, and (3) G-XF. The rates for those paths were based entirely on Line 401 costs, without any reductions for phase-ins. The CPUC decision for the 2004 GT&S rate case includes the following descriptions of how those rates were calculated in the GA I Settlement:[12]

> Incremental Line 401 (Schedule G-XF) Redwood path rates were designed using a load factor of 95%...Off-system Redwood Path rates were based on the incremental Line 401 cost-of-service and rates...The Silverado off-system rate was equal to Line 401 off-system rate since it assumes Line 401 is used to provide the service.

The rates adopted in the GA I Settlement for the GX-F, Redwood off-system and Silverado off-system paths are identical.[13] Page 79 of the Settlement Agreement indicates “G-XF charges are based on the embedded cost of Line 401 and a 95% load factor.” Page 76 of the settlement indicates the Redwood off-system rates “are based on Line 401's embedded costs and a 95 percent load factor” and the Silverado off-system flows “are assumed to flow on Line 401, and are priced at the Line 401 rate.”[14] The “As-Available” rates for the Redwood off-system and Silverado off-system paths were set at 110% of the Firm rates.[15]

Q. Did the Redwood core rates include any Line 401 costs?

A. No. The rates for the Redwood core path were based solely on the cost of Line 400 and Line 2 capacity that was directly assigned to core customers. Those lines run parallel to Line 401. That capacity was much less expensive than the Line 401 capacity because it was built many decades before Line 401. Core customers were entitled to that pre-existing “vintage” Redwood capacity because of commitments that PG&E made to obtain CPUC approval for the construction of Line 401. The Redwood core rates reflected the direct assignment of the vintage capacity to core customers. To the extent that core customers needed additional capacity on the Redwood path, they paid the higher Redwood noncore rates for that incremental capacity.

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[12] D.03-12-061, page 242

[13] Gas Accord I Settlement pages 76 and 79

[14] GA I Settlement, page 76, notes (d) and (g). The short-hand titled for Malin to off-system is Redwood off-system. The short-hand title for California gas and storage to off-system is Silverado off-system.

[15] GA I Settlement, page 78. The Firm rates were based solely on the Line 401 revenue requirement without any phase-in reductions.

Q. Did the Redwood noncore rates include any Line 401 costs?

A. Yes. The Redwood noncore rates reflected a blend of the vintage Redwood capacity and Line 401 costs. The vintage capacity remaining after the core direct assignment was assigned to noncore. In addition, specified amounts of Line 401 capacity were included in the Redwood noncore rates. The Line 401 capacity assigned to noncore equaled the difference between the total anticipated noncore demand for Redwood path capacity and the vintage Redwood capacity assigned to noncore.[16]

Q. Did the amount of Line 401 capacity included in the Redwood noncore rates increase every year under the Gas Accord I settlement?

A. Yes. The Gas Accord I settlement refers to those increases as the "Line 401 Cost Phase-in to On-System rates."[17] The Redwood noncore rates only included a portion of the Line 401 revenue requirement because noncore customers were entitled to vintage Redwood capacity and were only expected to use a portion of Line 401. The Redwood noncore rates reflected the anticipated usage of Line 401 by noncore customers. The phase-in was not a disallowance of Line 401 costs. The phase in reflected a direct assignment of Line 401 capacity to on-system noncore customers based on their anticipated usage of Line 401.[18]

Q. Were the Redwood core and noncore customers the only customers that were entitled to vintage Redwood capacity?

A. Yes. The other customer groups that used the Redwood path were assumed to exclusively use Line 401 capacity. Those customers took service under the Redwood off-system, Silverado off-system and G-XF rates. The approved revenue requirements for those rates included the entire Line 401 revenue requirement. The rates were determined by dividing the entire Line 401 revenue requirement by billing determinates that assumed 95 percent utilization of design capacity. The capacity utilization factor was set at 95 percent because of commitments PG&E made to obtain CPUC approval for the construction of Line 401.[19]

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[16] GA I Settlement, page 4, paragraph 7

[17] GA I Settlement, page 38

[18] PG&E Report on the Gas Accord Settlement, August 21, 1996, page 1-16, line 5

[19] D.03-12-061, pages 295 and 306

Q. Was the entire Line 401 revenue requirement included in the revenue requirements adopted in the Gas Accord I settlement?

A. Yes. The entire Line 401 revenue requirement was used to calculate the backbone transmission rates for the Redwood off-system, Silverado off-system and G-XF paths. The revenue requirements used to set those rates are, by definition, part of the revenue requirements adopted in the Gas Accord I settlement.

Q. Does the fact that some of the backbone transmission rates adopted in the Gas Accord did not include any Line 401 costs mean that Line 401 should be entirely excluded from the Gas Accord I adopted revenue requirement?

A. No. Line 401 was excluded entirely from the Redwood core rates and the Baja rates. The reason for that exclusion is obvious. Those paths were not expected to use any Line 401 capacity. The fact that those two rates did not include any Line 401 costs does not mean that Line 401 was entirely excluded from the overall revenue requirement adopted in the Gas Accord I settlement. Similarly, the phase in of Line 401 costs into the Redwood noncore rates does not mean that a portion of Line 401 was excluded from the overall adopted revenue requirement.

Q. Mr. O'Loughlin claims the Gas Accord I adopted revenue requirements shown on Table 5-3 of the Overland report are significantly higher than the revenue requirements adopted in the Gas Accord I Settlement. Does the Gas Accord Settlement Agreement show the adopted revenue requirements?

A. No. The Gas Accord Settlement Agreement does not contain any overall revenue requirement figures. Instead, the tables attached to the settlement show the adopted rates for each service by year.

Q. How did Overland determine the adopted revenue requirements for the GA I period?

A. The adopted revenue requirements shown in the Overland Report were calculated from the Gas Accord I Settlement workpapers using a three step process. First the 1996 non-Line 401 revenue requirement was taken from the Settlement workpaper 12-2 and escalated using the 2.5 percent escalation factor specified in the settlement (without any escalation for 1997). Second, the Line 401 revenue requirements for each year were taken from Settlement Workpaper 15-1. Third, the adopted revenue requirements for customer access charges, NOx plant additions and storage carrying charges were added.

The details of Overland's calculations are shown on the following table.

Table 4-5
GA I Settlement Period Revenue Requirements
Per Overland
1997 to 2002
Dollars in Thousands

Description	1997	1998	1999	2000	2001	2002
1996 Revenue Requirement Excluding Line 401	273,485	273,485	273,485	273,485	273,485	273,485
Escalation Factor (2.5 percent /year)	1.0000	1.0250	1.0506	1.0769	1.1038	1.1314
Revenue Requirement Excluding Line 401	273,485	280,322	287,330	294,513	301,876	309,423
Line 401 Revenue Requirement	120,637	116,790	113,032	109,363	105,674	101,967
Customer Access Charge Revenue Requirement	5,658	5,799	5,944	6,093	6,245	6,401
Nox Plant Additions Revenue Requirement	0	3,000	5,200	5,800	5,500	5,200
Storage Carrying Charges	6,190	6,345	6,503	6,666	6,833	7,003
Rounding	na	na	(2)	(3)	(4)	(3)
Adopted Revenue Requirement (Table 5-3)	405,970	412,256	418,008	422,432	426,124	429,992
Source for 1996 RRQ Excluding Line 401 is GA Settlement WP 12-1 (See next Table). Escalation Factor is 2.5 percent per year per GA I Settlement Page 40						
Other Sources: Settlement WPs 15-1 (Line 401), 21-2 to 21-7 (CAC), 14-1 (Nox); 24-1 (Storage CC)						

The details of the 1996 revenue requirement excluding Line 401 are shown below.

Table 4-6
GA I Settlement Revenue Requirements
Excluding Line 401
Year 1996
Dollars in Thousands

Function	Amount
Production	516
Gathering	29,638
Storage Inventory	20,908
Storage Injection	9,110
Storage Withdrawal	14,288
Transmission North (excludes 401)	23,515
Transmission Other	16,789
Transmission South	39,789
Transmission Local	118,932
Total	273,485
Source: GA I Settlement Workpaper 12-1	

The same adopted revenue requirements can be calculated using the GA I Settlement rate design workpapers as shown below.

Table 4-7 GA I Period Adopted Revenue Requirement Per Overland Calculated Using Alternative Source GA I Settlement Workpapers 1997 to 2002 Dollars in Thousands						
Description	1997	1998	1999	2000	2001	2002
Malin - Lines 300 / 2	23,517	24,105	24,708	25,325	25,958	26,607
Malin - L 401	120,637	116,790	113,032	109,363	105,674	101,967
Topock - Line 300	39,789	43,783	47,003	48,648	49,419	50,217
Other Backbone Transmission	16,786	17,206	17,3636	18,077	18,529	18,992
Storage (Total)	44,306	45,413	46,549	47,712	48,905	50,128
Gathering	12,553	12,867	13,189	13,518	13,856	14,203
Production	516	529	542	556	570	584
Local Transmission	136,018	139,416	142,902	146,474	150,138	153,890
Customer Access Charge	5,658	5,799	5,944	6,093	6,245	6,401
Storage Carrying Charges (Note A)	6,190	6,345	6,503	6,666	6,833	7,003
Rounding	0	3	(1)	(2)	(3)	0
Adopted Revenue Requirement	405,970	412,256	418,007	422,430	426,124	429,992
Source: GA I Settlement Workpapers 18-3, 18-15, 18-27, 18-39, 18-51, 18-63, 19-2 to 19-6 (Local Trans), 21-2 to 21-7 (CAC) and 24-1 (Storage CC)						
Note A: Escalated at 2.5 percent per year						

Q. How did Mr. O'Loughlin calculate his lower adopted amounts?

A. Mr. O'Loughlin calculated his lower adopted revenue requirements from the same Settlement workpapers. The only differences between his calculations and Overland's calculations are the treatment of Line 401 and customer access charge revenue requirements.[20] Overland included the entire Line 401 revenue requirement in its adopted revenue requirement. Mr. O'Loughlin included the following portions of the Line 401 revenue requirement in his adopted revenue requirements.

[20] Customer Access Charge Revenue Requirements are addressed in Sections 12 and 13.

Table 4-8 Percentage of Line 401 Revenue Requirement Included in O'Loughlin's GA I Adopted Revenue Requirements For the Years Shown on Overland Table 5-3	
Year	Percent
1997	38
1998	44
1999	50
2000	53
2001	56
2002	59
Source: Exhibit __ (MPO-3), page 6, Figure 3-2	

The difference between the GA I adopted revenue requirements presented by Overland and Mr. O'Loughlin is largely attributable to Mr. O'Loughlin's interpretation of the provisions of the settlement pertaining to the phase-in of Line 401 costs into the backbone transmission rates for the Redwood noncore path.[21]

Q. Did the Gas Accord I Settlement provide PG&E with a market opportunity to recover the entire Line 401 revenue requirement?

A. Yes. PG&E was permitted to charge firm transmission rates that reflected the entire Line 401 revenue to all customers that utilized the Redwood path to deliver gas to off-system delivery points. The As-Available rates for off-system deliveries equaled 110% of the firm rates. In addition, the Redwood noncore rates were designed to recover roughly half of the Line 401 revenue requirement. In combination, the rates adopted in the GA I Settlement provided PG&E with an opportunity to recover the entire Line 401 revenue requirement. The GA I Settlement also provided an opportunity to recover part of the Line 401 revenue requirements through buy-outs of existing G-XF contracts.[22]

Q. Were any of the GX-F contracts bought out?

A. Yes. Southern California Edison (SCE) agreed to buyout its Line 401 contract in September 2006. The buyout was effective on March 1, 1998 when the rates adopted in

[21] Section 12 provides a complete reconciliation of Overland's adopted revenue requirements and Mr. O'Loughlin's adopted revenue requirements.

[22] GA I Settlement, page 32

the GA I Settlement were implemented. SCE made an $80 million buyout payment to PG&E at that time.

PG&E proposed having shareholders retain the $80 million buyout payment because shareholders were "solely at risk for Expansion (Line 401) revenues."[23] The Commission agreed with that proposal. Resolution G-3288, dated November 19, 1997, states:[24]

> PG&E is at risk for the 200 Mmcf/d of capacity relinquished by Edison...In order to mitigate the risk for PG&E shareholders, Edison agreed to pay PG&E the $80 million. Since under the terms of the Gas Accord, PG&E is at risk for all of its unsubscribed intrastate transmission capacity, the $80 million...may not fully mitigate PG&E's risk...
>
> ...[N]one of the parties to the Gas Accord opposed PG&E's proposal to keep the $80 million...Under these circumstances we cannot find that PG&E's proposal is inconsistent with the intent of the parties to the Gas Accord.

Resolution G-3288 directly links the ratemaking treatment of the $80 million buyout payment to the Line 401 throughput risk assumed by PG&E under the GA I Settlement. The buyout payment directly compensated PG&E for part of the Line 401 revenue requirement.

Q. Has PG&E admitted that the GA I rates provided a market opportunity to recover the entire Line 401 revenue requirement?

A. Yes. PG&E's response to OCHP-11 admits:

> Theoretically, the Gas Accord I (settlement) provided an opportunity for PG&E to recover the entire backbone, including Line 401, revenue requirement if on-system gas demands were sufficiently high, and off-system demands and prices were sufficiently high...
>
> ...PG&E had the opportunity to recover the entire Line 401 revenue requirement if Line 401 were fully subscribed, or fully utilized, at non-discounted rates.

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[23] OCHP-14, PG&E Advice Letter 2023-G, page 2

[24] OC-185, Attachment 2, Resolution G-3288, pages 9 and 10

Q. The Line 401 rates for off-system deliveries were calculated using a 95 percent load factor. Was Line 401 heavily utilized during the Gas Accord I period?

A. Yes. The CPUC decision in the 2004 Test Year GT&S rate case indicates "As a result of price advantages for Canadian gas, the Redwood path, including Line 401, was highly utilized throughout the Gas Accord period."[25] The decision also states: [26]

> We note that the 95% load factor is very close to the load factors experienced on the combined Redwood paths during the Gas Accord period. For 1998, 1999, 2000, 2001 and 2002, the combined Redwood Path load factors were 95%, 92%, 96%, 93% and 91% respectively.

The Redwood path consists of the Redwood vintage capacity and Line 401. The actual Redwood path load factors imply that Line 401 was heavily utilized during the GA I period.

Q. Do the GT&S actual financial results demonstrate that the GA I Settlement provided PG&E with a real market opportunity to recover the entire Line 401 revenue requirement?

A. Yes. The GT&S actual return on equity averaged 16.5 percent during 1999 to 2002 as shown on Overland's revised Table 5-1. PG&E actual revenues exceeded the amount needed to earn its authorized return on equity by $238 million during those four years.[27]

Q. Can you point to any other indications that market opportunity provided by the GA I Settlement was real?

A. Yes. PG&E completed a capacity expansion project for Line 401 in September 2002. The project increased system capacity by 220 Mdth/d. The total cost of the project was $36.4 million.[28] PG&E would not have expanded the capacity of Line 401 if it did not have a market opportunity to recover the Line 401 revenue requirement.

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[25] D.03-12-061, page 276. Repeating a statement made by PG&E on Page 3-8, Line 16, of PG&E's Rebuttal Testimony in the 2004 Test Year case.

[26] D.03-12-061, page 306.

[27] Revised Overland Table 5-2.

[28] PG&E January 2003 capital expenditures workpapers in the 2004 GT&S Rate Case, page 25, Line 401 Capacity Loops project.

1997 O&M Expense Escalation

Q. How did Overland calculate adopted functional O&M during the Gas Accord I period?

A. Overland took the adopted functional O&M for 1996 from the settlement workpapers and escalated that amount by 2.5 percent per year over the period 1997 to 2002.[29]

Q. What was the basis for the 2.5 percent escalation factor?

A. Under the GA I Settlement, the transmission and storage rates for 1997 reflected the 1996 revenue requirements adopted in the 1996 General Rate Case. The adopted rates for 1998 to 2002 reflected the 1997 rates escalated at an annual rate of 2.5 percent.[30]

The GA I Settlement did not adopt a separate escalation factor for O&M. Overland applied the overall rate escalation factor to O&M expense because an assumed O&M escalation factor of 2.5 percent, while below inflation, was not implausible with productivity improvements.[31]

Q. Mr. O'Loughlin relies on The Gas Accord I Settlement rate design workpapers titled "Backbone Transmission MFV Rate" for each year to support his claim that the GA I Settlement adopted an escalation factor specifically for O&M. Do you agree with that?

A. No. The backbone transmission rate design workpapers show annual cost-of-service elements for each path, including an amount for O&M.[32] All of the individual elements shown on those pages increase at the same rate of 2.5 percent per year, with the exception of Line 401 costs and NOx capital additions. The cost elements that largely reflect sunk costs, such as depreciation and return on rate base, increase at the same rate as the cost elements for current expenditures.

The individual cost element amounts do not have any impact on the rates developed in the rate design schedules because the rates are based on the total revenue requirement

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[29] The methodology described above does not apply to Line 401 O&M. Line 401 O&M was accounted for separately in the Gas Accord Settlement Workpapers.

[30] GA I Settlement Pages 40 to 42. The Revenue requirements for Line 401 and the NOx adder projects were calculated separately and were not subject to the 2.5 percent escalation. D.03-12-061, page 243

[31] Overland Report, page 2-9

[32] GA Settlement workpaper pages 18-3, 18-15, 18-27, 18-27 and 18-39, 18-51 and 18-63

shown for each rate category, and the total revenue requirements must (and do) increase at the 2.5 percent rate specified in the Settlement Agreement.[33]

The rates of increase in the individual non-Line 401 cost elements do not have any impact on the reservation and usage charges developed in the rate design workpapers because the reservation and usage charges must (and do) increase at the 2.5 percent rate specified in the settlement when they are properly adjusted to eliminate the impact of the Line 401 and NOx revenue requirements that were not escalated at the 2.5 percent rate.[34]

The rates of increase in the individual non-Line 401 cost elements shown on the rate design workpapers did not have any impact on the interests of the Commission or the parties because they did not have any impact on rates or services.

Some gas system cost of service elements are relatively fixed and not subject to general inflation, such as depreciation expense. Rate base for existing pipelines generally decline over time. Those factors imply that an overall escalation factor applied to customer rates for the prior year consists of a higher escalation factor for current expenditures, such as O&M, and a lower rate for depreciation and investment return.

Escalating depreciation and return-on-rate base at the same rate as O&M is contrary to sound cost-of-service principles. The year to year rates of increase in the individual non-Line 401 cost elements shown on the rate design workpapers were superfluous and contrary to sound cost-of-service principles. The annual rate of change for each individual cost element should not be construed as adopting a specific escalation factor for that cost element.

Q. Did the CPUC comment on the 2.5 percent escalation factor in the decision that approved the GA I Settlement?

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[33] Excluding Line 401 revenue requirements and the revenue requirements for NOx capital additions. Those revenue requirements were calculated separately in the GA I workpapers and were not escalated at 2.5 percent.

[34] GA I Settlement workpapers 18-3 to 18-6, 18-15 to 18-18, 18-27 to 18-30, and so forth

A. Yes. The decision states:[35]

> The Gas Accord holds few direct economic benefits for core customers. The Gas Accord offers immediate short-term rate reductions, but they are offset by 2.5% annual escalation through 2002. The settled escalation factor may be a reasonable estimate of general inflation, but it seems to exclude productivity opportunities, and it applies to entire transmission rates. Escalation is not restricted to cost elements that are generally subject to inflation. The embedded costs of existing pipelines are driven by sunk capital costs, not capital additions or operations and maintenance costs that might be affected by inflation.

As noted by the Commission, the cost-of-service elements reflected in rates are not all equally impacted by inflation. The overall escalation factor applied to transmission and storage rates was a composite escalation factor for the separate cost-of-service elements underlying the rates. The Commission correctly viewed the 2.5 percent rate escalation factor as a composite that included a higher rate for current expenditures, including O&M, and an escalation rate of zero for sunk costs.

Q. Under the Gas Accord I Settlement, the overall rate escalation factor of 2.5 percent was not applied to 1997 rates. Why should it be applied to 1997 adopted O&M?

A. Overland did not attempt to unbundle the composite escalation factor for total customer rates into the underlying cost-of-service elements. The 2.5 percent escalation factor should be applied to 1997 O&M to, at least partially, account for the higher O&M escalation rate embedded in the composite escalation factors adopted in the settlement, including the zero percent composite factor used in 1997.

Applying the 2.5 percent escalation factor to 1997 O&M costs increases O&M in 1997 and each subsequent year by 2.5 percent. Those increases more accurately reflect the substance of the O&M cost recovery provided by the adopted rates compared to the alternative of not applying the escalation factor to 1997 O&M.

Overland did not apply the adopted overall 1997 rate escalation factor of zero percent to 1997 O&M because it was not a realistic portrayal of the O&M escalation rate embedded in the composite escalation factor applied to customer rates.

[35] OCHP-4, Attachment 2, D.97-08-055, page 27

Q. Would reducing adopted O&M by 2.5 percent a year, as proposed by Mr. O'Loughin, increase adopted capital expenditures?

A. Yes. The rates adopted in the GA I Settlement recover all of the underlying adopted elements of the cost of service. Reducing adopted O&M, as proposed by Mr. O'Loughlin, increases the amount of the revenues available to support capital expenditures. Adopting Mr. O'Loughlin's position on O&M escalation increases adopted capital expenditures by $21 million over the GA I period, as shown below.[36]

Table 4-9
Impact of 1997 O&M Escalation
On Adopted GA I Capital Expenditures
Dollars in Thousands

Year	Adopted Capex Without 1997 O&M Escalation	Adopted Capex With 1997 O&M Escalation	Increase in Adopted Capex
1997	76,800	73,300	3,500
1998	76,800	73,300	3,500
1999	76,800	73,300	3,500
2000	76,800	73,300	3,500
2001	76,800	73,300	3,500
2002	76,800	73,300	3,500
Total	460,800	439,800	21,000

Sources: Overland Report Table 4-1 and Overland Rebuttal Workpapers.
Note: Amounts are shown for illustration purposes and do not reflect the revisions for common plant and NOx plant additions described on page 8.

Adopting an O&M escalation rate of zero percent in 1997 would reduce adopted O&M by $8.7 million and increase adopted capital expenditures by $21 million over the GA I rate period.

[36] Overland's methodology for imputing adopted GA I capital expenditures is described in Section 5. The adopted capex amounts without 1997 escalation were calculated by preparing an alternative case using Overland's GA I period capital expenditures imputation model. Overland workpapers 4-1 to 4-4 show the model (without the revisions adopted in Section 3).

Section 5

1997 to 2002 Adopted Capital Expenditures

Q. Are Mr. O'Loughlin's recommended GA I adopted capital expenditures higher than the amounts recommended by Overland?

A. Yes. Mr. O'Loughlin's GA I adopted capital expenditures are $33.8 million higher than the amount recommended by Overland, as shown on the following table.

Table 5-1
Comparison of Adopted Capital Expenditures
Overland Revised Compared to O'Loughlin
1997 to 2002
Dollars in Thousands

Year	Overland	O'Loughlin	Difference
1997	75,200	43,430	31,770
1998	75,200	101,056	(25,856)
1999	75,200	90,916	(15,716)
2000	75,200	84,828	(9,628)
2001	75,200	89,594	(14,394)
2002	75,200	75,200	0
Total	451,200	485,024	(33,824)

Source: Overland Revised Table 4-1 and MPO Workpapers 134 to 137

Q. What issues caused the differences?

A. Overland and Mr. O'Loughlin used different methodologies to impute GA I Capital expenditures. As a result, a detailed reconciliation of the differences by issue is not meaningful.

Q. Please describe the methodology used by Overland.

A. Overland imputed capital expenditures using a standard revenue requirements model to solve for the plant additions that produce the authorized rate of return for each year given revenues equal to the non-Line 401 revenue requirements adopted in the GA I settlement.[37]

The analysis excludes Line 401 because Line 401 was addressed separately in the GA I Settlement workpapers. Line 401 capital expenditures were assumed to be zero

[37] Overland Report page 29. Overland imputed adopted operating expense and other rate base investments for each year in the study period and solved the model for the annual capital expenditure amounts that produced PG&E's authorized return-on-equity. The calculations are shown on Overland workpapers 4-1 to 4-4.

consistent with the forecast of Line 401 revenue requirement shown on GA I Settlement Workpaper 15-2.[38]

Q. Please describe the methodology used by Mr. O'Loughlin.

A. The workpapers supporting Mr. O'Loughlin's calculations are somewhat convoluted and his methodology includes a method for smoothing fluctuations in annual amounts that is largely a black box. However, when distilled to the basics, his methodology is fairly simple.

Mr. O'Loughlin escalated 1996 net plant and depreciation expense using the escalation factors for GT&S rates adopted in the GA I Settlement.[39] He uses those values to solve for adopted capital expenditures using the following formula.

Capital Expenditures = Change in Net Plant + Depreciation Expense

The following table shows Mr. O'Loughlin's calculations.[40]

Table 5-2
GA I Adopted Capital Expenditures
O'Loughlin Methodology - As Distilled by Overland
Dollars in Thousands

Description	1997	1998	1999	2000	2001	2002
Ending Net Plant	1,011,259	1,043,067	1,068,453	1,095,235	1,125,333	1,139,548
Beginning Net Plant	1,021,730	1,011,259	1,043,067	1,068,453	1,095,235	1,125,333
Increase in Net Plant	(10,471)	31,808	25,386	26,782	30,098	14,215
Depreciation Expense	53,901	55,249	56,630	58,045	59,497	60,984
Add Nox Capex	0	14,000	8,900	0	0	0
Rounding	0	(1)	0	1	(1)	1
Total Capex Per MPO	43,430	101,056	90,916	84,828	89,594	75,200
Source: MPO Workpapers, pages 134 and 135						

Q. Are the accounting mechanics of that formula valid?

A. Yes. The accounting mechanics are valid.[41] The validity of the results, however, depends on the validity of the inputs.

[38] That assumption was reasonable because Line 401 was new.

[39] Those factors were zero percent in 1997 and 2.5 percent in 1998 to 2002.

[40] As distilled by Overland.

[41] Both Overland and O'Loughlin include cost of removal in capital expenditures because the actual capital expenditures amounts provided by PG&E, and used in the comparison, include cost of removal.

Q. The table starts with ending net plant. How did Mr. O'Loughlin calculate his ending net plant figures?

A. Mr. O'Loughin calculated a "mid-point" net plant amount for each year by escalating the 1996 adopted net plant amount shown in the GA I Settlement workpapers at the overall growth rate in the adopted revenue requirement. He calculated the year-end net plant figures shown in his workpapers from the mid-point net plant amounts using a smoothing method that is basically a black box. That process involved dividing each year into two halves and using "Excel's Solver function" to "minimize the sum of the squared differences between H1 and H2" over the period 1997 to 2003.[42]

Q. Does the smoothing methodology have a significant impact on the year-end net plant values over the entire GA I Period?

A. No. The smoothing method shifts amounts between years but does not have a significant impact over the six year GA I Period. This can be demonstrated by calculating the year-end net plant amounts as a simple average of the current year and subsequent year mid-points, as shown below.[43]

Table 5-3
Comparison of MPO Year End Net Plant
To Calculated Values (Average of Mid-Points)
GA I Period - 1997 to 2002
Dollars in Thousands

Year	MPO Mid-Point	Calculated Year -End	Year-End Per MPO	Difference
1997	1,003,676	1,016,376	1,011,259	5,117
1998	1,029,075	1,042,092	1,043,067	(976)
1999	1,055,108	1,068,450	1,068,453	(3)
2000	1,081,792	1,095,468	1,095,235	233
2001	1,109,144	1,123,162	1,125,333	(2,172)
2002	1,137,179	1,137,179	1,139,548	(2,369)
2003	1,137,179	NA	NA	NA
Total	NA	6,482,726	6,482,895	(170)

Source: MPO Mid-Point and Year-End is from MPO workpapers pages 134 and 135

Note: Calculated Year-End equals the average of current year and subsequent year mid-points

Q. Why did Mr. O'Loughlin set 2003 mid-point net plant equal to 2002 mid-point net plant?

[42] MPO Workpapers, page 138.

[43] The mid-points represent the net plant balance as of June 30th each year. The year-end values represent the net plant balance as of December 31, each year. The average of the June values for the current and subsequent year is an alternative method for calculating the December 31 balance for the current year.

A. Mr. O'Loughlin set the 2003 mid-point net plant equal to the 2003 mid-point based on the terms of the Gas Accord II Settlement Agreement, dated May 17, 2002. That agreement set 2003 GT&S rate equal to the rates in effect on January 1, 2002.[44] Mr. O'Loughlin included 2003 net plant in his calculations of 2002 capital expenditures and in the "Excel Solver" calculations used to determine capital expenditures for the years 1997 to 2002.

Q. Should GA I adopted capital expenditures be based on the terms of the GA II Settlement Agreement?

A. No. The GA I Settlement Agreement is dated August 21, 1996. The GA I Settlement covered the rate years 1997 to 2002. The GA I Settlement did not adopt, or even discuss, rates for 2003. Using the terms of the May 17, 2002 GA II Settlement Agreement to determine adopted GA I capital expenditures is not appropriate.

Q. One of the critical assumptions made by Mr. O'Loughlin is that net plant escalates at the same rate as the GT&S rates adopted in the GA I Settlement. Is that a valid assumption?

A. No. As explained in Section 4, the 2.5% escalation factor adopted in the GA I Settlement is a composite of the escalation rates for the individual cost of service elements that produce the adopted revenue requirements. Net plant consists largely of the historical cost of past plant investments. Those past investments are not subject to inflation. Applying the overall rate of growth in customer rates to net plant is not a valid approach.

Q. Another critical assumption made by Mr. O'Loughlin is that depreciation expense escalates at the same rate as the adopted GT&S rates. Is that a valid assumption?

A. No. Depreciation expense represents the amortization of the historical cost of past capital expenditures over the service lives of the facilities. Those past investments are not subject to inflation, and escalating depreciation expense at the rate of increase for GT&S rates is not a valid approach.

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[44] GA II Settlement Agreement, page 2. Mr. O'Loughlin refers to the GA II Settlement as the "Gas Accord I Extension." The cover sheet of the May 17, 2002 agreement that extended 2002 rates through December 2003 indicates the agreement is the "Gas Accord II Settlement Agreement." D.02-08-070, Appendix A. The Decision approving the agreement is titled "Opinion Regarding the Joint Motion for Approval of the Gas Accord II Settlement Agreement." For those reasons, Overland refers to the agreement as the "Gas Accord II Settlement."

Q. Mr. O'Loughlin cites the GA I Settlement rate design workpapers as support for escalating net plant and depreciation expense at the same rate as the adopted GT&S rates. Do those workpapers justify Mr. O'Loughlin's position?

A. No. The rate design workpapers cited by Mr. O'Loughlin do not show net plant or rate base values. All of the cost of service elements shown on those schedules, including depreciation and return on rate base, escalate at the same rate as the overall revenue requirement, with the exception of Line 401 costs and NOx capital additions.[45] The cost elements that largely reflect sunk costs, such as depreciation and return on rate base, increase at the same rate as the cost elements for current expenditures.

As explained in Section 4, the rates of increase in the individual non-Line 401 cost elements shown on the rate design workpapers did not have any impact on the interests of the Commission or the parties because they did not have any impact on rates or services.

Escalating depreciation and return-on-rate base at the same rate as O&M is contrary to sound cost-of-service principles. The year-to-year rates of increase in the individual non-Line 401 cost elements shown on the rate design workpapers were superfluous and contrary to sound cost-of-service principles. The annual rates of change for each individual cost element should not be construed as adopting a specific escalation factor for that cost element.

Q. Did the escalation rates used by Mr. O'Loughlin cause his adopted capital expenditure amounts to be overstated?

A. No. Overland's adopted capital expenditure amounts for 1997 to 2002 are $34 million lower than Mr. O'Loughlin's adopted amounts. That difference is consistent with the fact that net plant consists largely of sunk costs that are not subject to inflation.

<u>O'Loughlin Criticisms of Overland Approach</u>

Q. Does Mr. O'Loughlin dispute the validity of Overland's basic approach?

A. Not entirely. Page 49 of Exhibit__(MPO-1) indicates:

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[45] The rate design workpapers are reproduced on Exhibit___(MPO-14). See pages 18-3, 18-15, 18-27, 18-27 and 18-39, 18-51 and 18-63.

> Overland relies on a model based approach which solves for annual capital expenditures required to achieve the adopted revenue requirement. While I agree with the notion of solving for capital expenditures consistent with the adopted revenue requirement growth, this approach only works if the assumptions and inputs are consistent with the settlement...Overland used assumptions and methodologies that are inconsistent with the settlement.

Q. Did Overland use assumptions and methodologies that were inconsistent with the settlement?

A. No. Overland's assumptions and methodologies reflect the 1996 to 2002 revenue requirements adopted in the GA I Settlement.

Q. Please identify the specific issues which Mr. O'Loughlin raises regarding Overland's assumptions and methodologies.

A. Mr. O'Loughlin only presents four specific criticisms of Overland's calculations. Mr. O'Loughlin claims:

- Overland overstated depreciation expense;
- Overland overstated Accumulated Deferred Income Tax balances;
- Overland should not have excluded capital expenditures for common plant from its adopted amounts; and
- Overland indirectly imputed higher capital expenditures for NOx plant additions than the amounts specified in the GA I Settlement workpapers.

Q. Please describe how Overland calculated the adopted depreciation expense used in its GA I capital expenditures model.

A. Overland calculated an average book depreciation rate for GT&S operations from GA I Settlement Workpapers 12-1 and 12-3. The book depreciation rate of 3.01 percent was calculated by dividing 1996 book depreciation by the weighted average gross plant balance for 1996.[46]

[46] The calculations excluded Line 401. Line 401 is not included in Overland's GA I capital expenditures model.

Overland calculated adopted depreciation expense for each year from 1997 to 2002 by applying the average book depreciation rate to the average gross plant for the applicable year. The calculations are shown on Overland workpaper 4-2.

Q. Does Overland's methodology overstate adopted depreciation expense?

A. No. Overland used the standard methodology for calculating depreciation expense. Under Overland's methodology, the book depreciation rate remains constant over the entire GA I period. This is consistent with the settlement, which does not authorize PG&E to reduce depreciation rates below the rates previously approved by the CPUC.

In contrast, Mr. O'Loughlin reduces adopted depreciation rates gradually over the GA I Period, as shown on the following table.

Table 5-4
Average Book Depreciation Rates
Produced by O'Loughlin Depreciation Escalation
GA I Period - 1997 to 2002
Dollars in Thousands

Year	Depreciation Expense	Mid-Year Gross Plant	Depreciation Rate (%)
1996	53,901	1,788,460	3.01
1997	53,901	1,829,141	2.95
1998	55,249	1,889,498	2.92
1999	56,630	1,951,364	2.90
2000	58,045	2,014,777	2.88
2001	59,497	2,079,775	2.86
2002	60,984	2,146,398	2.84
Source: MPO workpapers pages 134 and 135			

Q. Does reducing depreciation rates between rate cases harm ratepayers?

A. Yes. Reducing depreciation rates between rate cases increases rate base in future rate cases, without a corresponding reduction in current rates. Reducing depreciation rates between rate cases increases future depreciation expense by increasing the unamortized plant cost that must be charged against operating income as depreciation expense over the remaining life of the plant.

Q. How did Overland calculate Accumulated Deferred Income Taxes?

A. Overland calculated current year deferred income tax expense for accelerated depreciation consistent with the Commission's income tax normalization policy. The deferred tax expense provisions were calculated as a constant percentage of gross plant, with an adjustment for additional normalized vintages entering the turn-around period each year.

The deferred tax percentage used by Overland was calculated by dividing 1996 deferred tax expense by 1996 weighted average plant. The adjustment for additional vintages entering the turn-around period reflected the Commission's income tax normalization policy. [47]

The Accumulated Deferred Income Tax (ADIT) balances included in rate base were calculated by posting the adopted deferred income tax provisions to the ending 1996 ADIT balance from the Gas Accord I workpapers. The calculations of the adopted deferred income tax provision and related ADIT balances are shown on Overland workpapers 4-1 and 4-2.

Q. Does Overland's methodology overstate ADIT?

A. No. Overland's methodology is sound and consistent with the Commission's income tax normalization policy. Deferred income tax expense is a function of book and tax depreciation. Calculating deferred tax expense as a constant percentage of gross plant, reflects the direct linkage between gross plant and depreciation. The adjustment for vintages entering the turn-around period reflects the CPUC's income tax normalization policy. Mr. O'Loughlin ignores the Commissions' income tax normalization policy.

Q. Have you accepted Mr. O'Loughlin's position on GA I period common plant?

A. Yes. Overland excluded capital additions for common plant from its GA I period adopted amounts based on its understanding of the scope of the actual capital expenditures included in the comparison. Mr. O'Loughlin and Overland both used the response to OC-38 as the source for actual capital expenditures. Overland interpreted that response as excluding common plant capital expenditures. After Mr. O'Loughlin filed his testimony, Overland submitted a discovery question to clarify the scope of OC-38. PG&E's response includes a direct representation that the response to OC-38 included common

[47] The Commission authorized normalization of federal depreciation temporary differences beginning with 1981 plant vintages. Most utility plant has a 15 year tax life. As a result, the 1996 deferred tax provision consisted almost entirely of vintages that were still in the deferral phase. The adjustment represents one additional normalized vintage entering the turn-around phase each year during the period 1997 to 2002. See Overland's response to PG&E discovery question 8 for additional explanation.

plant and Overland accepted that representation.[48] Overland Revised Table 4-1 adopts Mr. O'Loughlin's position on GA I common plant capital expenditures.

Q. How did Overland address the additional revenue requirements that were included in the GA I Settlement for NOx capital additions?

A. Overland's capital expenditures model used the total revenue requirements adopted in the GA I Settlement, including the additional revenue requirements for NOx capital additions.[49]

Q. Have you accepted Mr. O'Loughlin's general approach to handling the NOx additions?

A. Yes. GA I Settlement workpaper 14-1 shows the plant additions included in the separate NOx revenue requirements. Mr. O'Loughlin excludes the NOx additions from his basic imputation method and adds those plant additions to his result. That is a reasonable approach and I have accepted his method. Adopting Mr. O'Loughlin's approach to handling the NOx plant additions decreases adopted capital expenditures by $21.6 million over the six year GA I period. Overland's Revised Table 4-1 adopts Mr. O'Loughlin's position on GA I NOx capital additions.

Q. The NOx plant additions only total $23 million. Why does using Mr. O'Loughlin's approach produce a $21.6 million reduction in Overland's adopted capital expenditures?

A. The adopted revenue requirements for the NOx plant additions exceed the amounts justified by the plant costs shown in the GA I Settlement workpapers, as shown on the following table.

[48] OCHP-24.

[49] Overland workpapers 4-1 and 4-3.

Table 5-5
Comparison of Adopted Nox Revenue Requirements
To Calculated Values
1998 to 2010
Dollars in Thousands

Description	1998	1999	2000	2001	2002
Plant Addition January 1	14,000	8,900	0	0	0
Average Gross Plant	14,000	22,900	22,900	22,900	22,900
Depreciation Rate	0.0453	0.0453	0.0453	0.0453	0.0453
Depreciation Expense	634	1,037	1,037	1,037	1,037
YE Accumulated Depreciation	634	1,672	2,709	3,746	4,784
Ave. Accumulated Depreciation	317	1,153	2,190	3,228	4,265
Average Rate Base	13,683	21,747	20,710	19,672	18,635
Rate of Return With Income Taxes	0.12226	0.12226	0.12226	0.12226	0.12226
Return with Income Taxes	1,673	2,659	2,532	2,405	2,278
Property Tax	145	231	220	209	198
Total Revenue Requirement	2,452	3,927	3,789	3,652	3,514
Settlement Revenue Requirement	3,000	5,200	5,800	5,500	5,200
Difference	548	1,273	2,011	1,848	1,686

Sources: GA I Settlement WP 14-1; Depreciation Rate source is 1996 GRC rate for Account 1125; Pre-Tax ROR calculated from MPO WP 118; Property Tax rate is 1996 average from GA I WP 12-1

The components of the NOx revenue requirements adopted in the GA I Settlement are not available, but they apparently included large incremental O&M and property tax expenses attributable to the NOx plant additions.

Overland's prior approach accounted for the return on investment, income taxes and depreciation expenses associated with the NOx plant additions.[50] Overland's prior approach did not account for any O&M and property tax expenses included in the incremental NOx revenue requirements adopted in the GA I Settlement. As a result, removing the NOx revenue requirements from Overland's model, and adding the NOx plant additions shown on GA I Settlement workpaper 14-1 to the result, reduces total adopted capital expenditures.

Overland's adopted O&M expenses are conservative because they do not include any of the incremental O&M expenses included in the NOx revenue requirements adopted in the GA I Settlement.

[50] Overland applied the average GT&S depreciation rate of 3.01 percent to the NOx additions. The depreciation rate specifically applicable to the NOx additions is 4.53 percent. GA I Settlement Workpaper 14-1 indicates PG&E used the depreciation rate for Account 1125 to calculate the NOx revenue requirements. PG&E's 1996 GRC testimony page 14-15 indicates the depreciation rate for that account is 4.53 percent.

Section 6

2003 Adopted Functional O&M Expenses

Q. Do you agree with Mr. O'Loughlin's adopted functional O&M expenses for 2003?

A. No. As shown below, Overland's adopted functional O&M for 2003 is $12.8 million higher than Mr. O'Loughlin's amount.

Table 6-1 2003 Adopted Functional O&M Overland Compared to O'Loughlin Dollars in Thousands	
Description	Amount
Overland Adopted Functional O&M	76,009
O'Loughlin Adopted Functional O&M	63,200
Difference	12,809
Sources: Overland Table 3-1 and Exhibit___(MPO-1), page 39, Figure 8.	

Q. What caused that difference?

A. The difference is the result of a fundamental disagreement about the correct basis for determining 2003 adopted O&M expenses. Overland set 2003 adopted O&M expenses equal to the 2003 forecast adopted in the 2004 Test Year GT&S rate case. Mr. O'Loughlin set the 2003 adopted O&M equal to his adopted amount for 2002.

Q. Why did Mr. O'Loughlin set 2003 adopted O&M expenses equal to his 2002 adopted amount?

A. The May 2002 GA II Settlement froze 2003 rates at the 2002 levels specified in the GA I Settlement. Based on that observation, Mr. O'Loughlin concludes "it is reasonable to use the same adopted O&M expense for 2003 as for 2002."[51]

Q. Should 2003 adopted O&M be set equal to 2002 adopted O&M?

A. No. The rate commitments adopted in the GA I Settlement expired on December 31, 2002. The decisions to propose, agree upon and approve the rates established by the GA II settlement were based on the decision makers' perceptions of the current (2003) cost of providing service.

[51] Exhibit__ (MPO-1), page 27.

The 2002 rates adopted in the GA I Settlement Agreement were based on the forecast of 1996 O&M adopted in the 1996 General Rate Case. A seven-year old forecast of O&M expenses for a year that ended six years prior to the effective date of the rates adopted in the Gas Accord II Settlement could not provide a rational basis for: (1) PG&E's decision to propose the rates adopted in the GA II Settlement; (2) the decisions of the other parties to agree to those rates; or (3) the decision of the CPUC to approve the rates.

Proposing, accepting and approving rates implies an understanding of the actual return on equity that will be produced by those rates. That understanding was based on the decision makers' perception of the current cost of providing service.

Imputing 2003 adopted O&M based on the 1996 GA I Settlement is not a reasonable approach. The 2003 forecasts from the 2004 Test Year GT&S rate case are the best available basis for determining the current cost of service components included in the GA II settlement rates.

Q. Did PG&E propose the rate freeze included in the GA II Settlement?

A. Yes. In October 2001, PG&E proposed extending the 2002 Gas Accord rates through December 31, 2004. PG&E's Application for approval of the extension indicated "if the simple, two-year extension of the Gas Accord is adopted as requested herein, PG&E will waive the 2.5 percent escalation for the two-year Gas Accord II extension period."[52]

PG&E's decisions to propose a rate freeze and subsequent decision to enter into the GA II Settlement were informed by its knowledge of the current cost of providing transmission and storage services. It is not plausible to suggest that PG&E made those decisions based on the forecasts of 1996 O&M expenses it prepared for its 1996 General Rate Case.

Q. Did PG&E provide the settling parties and the Commission with information about its current cost of providing service?

[52] Application of PG&E Proposing a Market Structure and Rules for the Northern California Natural Gas Industry For the Period Beginning January 1, 2003, October 9, 2001, page 13.

A. No. PG&E did not submit any information concerning the current cost of providing service with its application or the motion for approval of the settlement. PG&E apparently did not share any other information concerning the current cost of providing service with the other parties to the settlement or the CPUC.

Q. Did the CPUC recognize the need for information about the current cost of service?

A. Yes. The CPUC decision approving the settlement indicates:[53]

> [The California Department of General Services] also states that PG&E should be required to provide a full cost of service study on the backbone system and to disclose its revenues from those operations because DGS believes that PG&E has made substantially more than its costs and the authorized rate of return.

The settlement was submitted to the CPUC on May 20, 2002. The settling parties contended that prompt approval of the settlement was vitally important because gas transmission and storage had to be arranged in advance of the 2002 - 2003 winter heating season.[54] The CPUC considered DGS's request for a cost of service study and concluded: [55]

> DGS recommends that the Commission impose a condition that PG&E be required to submit a cost-of-service study before the Commission approves the proposed settlement agreement. The settling parties contend that a full cost-of-service review before approving the settlement is impractical given the short duration of the Gas Accord extension and the proposed start of the open season...
>
> We agree with the settling parties that DGS's recommendation for PG&E to submit a cost-of-service study, and the review of such a study, is impractical given the timeframe of the one-year extension, the open season process, and the upcoming winter season.

On September 30, 2002, the Commission directed PG&E to include a cost-of-service study with its rate proposal for 2004.[56] The requirement to provide a cost-of-service

[53] D.02-08-070, page 9.

[54] D.02-08-070, page 6.

[55] D.02-08-070, page 9.

[56] D.03-12-061, page 5, referring to an ALJ ruling dated September 30, 2002.

study was issued 32 days after the decision approving the GA II settlement. The CPUC clearly (and correctly) recognized that the reasonableness of proposed rates can not be determined by reviewing a seven year old cost-of-service forecast for a year that ended six years before the effective date of the proposed rates.

Q. Mr. O'Loughlin presents a time line on page 39 of his testimony. Have you prepared a time line?

A. Yes. Table 6-2 shows the relevant time line extending back to the mid-point of the recorded base year that PG&E used to develop its 1996 forecast for the 1996 GRC. Table 6-2 is shown on the following page.

PG&E filed its testimony in the 2004 Test Year GT&S rate case on January 13, 2003.[57] Table 9-1 of that testimony showed PG&E's O&M forecasts for 2003 and 2004.[58] PG&E's January 13, 2003 testimony was filed almost five months after the CPUC approved the Gas Accord II settlement. However, five months is a far shorter time period than the seven and one-half years that passed between the filing of PG&E's 1996 GRC testimony and Commission approval of the Gas Accord II Settlement.[59]

The 2003 O&M forecast filed on January 13, 2003, reflected PG&E's plans and anticipated staffing levels for 2003. In contrast, the forecast relied upon by Mr. O'Loughlin reflected PG&E's plans and anticipated staffing levels for the year 1996.

PG&E had detailed knowledge of its plans for 2003 when it proposed and subsequently agreed to the rate freeze included in the GA II settlement. The perceptions of the 2003 cost of service relied upon by the CPUC and other parties did not have the benefit of PG&E's detailed knowledge, but PG&E has not provided any evidence that the CPUC and other settling parties relied on the 1996 test year forecast that PG&E filed in December 1994.

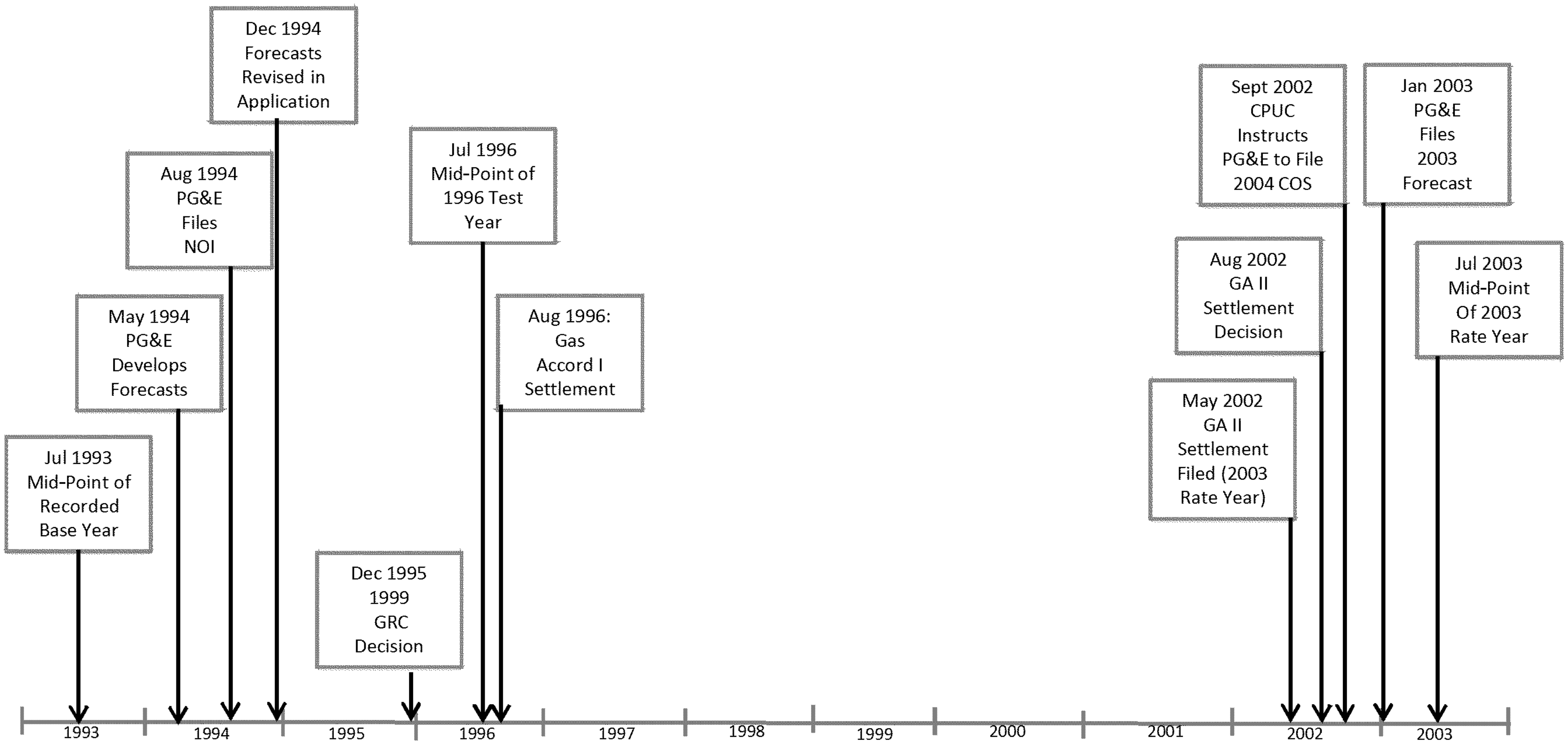
[57] D.03-12-061, page 5.

[58] OC-2. The O&M workpapers supporting PG&E's testimony were signed on January 29, 2003 and were presumably submitted on that date or shortly thereafter. The O&M workpapers provide PG&E's 2003 forecast by FERC Account.

[59] OCHP-20, PG&E prepared the forecasts for the 1996 GRC in the Spring of 1994 and submitted its Notice of Intent on August 12, 1994. PG&E submitted its Application on December 9, 1994. The Application updated the forecasts submitted with the NOI.

Table 6-2

2003 Adopted O&M Timeline



The 2003 O&M forecast adopted in the 2004 GT&S case is the best available proxy for the perceptions of the CPUC and other settling parties because both presumably reflected the realities of PG&E's 2003 GT&S operations. The 1996 forecast approved in the December 1996 General Rate Case decision did not, and could not, reflect the realities of 2003 GT&S operations.

The O&M forecast for the 1996 test year adopted seven years earlier could not have demonstrated the reasonableness of the rates adopted in the 2003 settlement. The CPUC based its approval of the GA II Settlement on its perception of the current cost of providing service. The 2003 forecast filed in January 2003 is the best available proxy for that information.

Q. Are rates supposed to be based on the current cost of providing service?

A. Yes. As a general regulatory policy matter, a utility and its customers are both entitled to rates that approximate the current cost of providing service, unless prior rate commitments dictate otherwise. The rate commitments adopted in the GA I Settlement expired on December 31, 2002. Mr. O'Loughlin has failed to show that the rates adopted in the GA II Settlement were intended to be representative of something other than the current (2003) cost of providing service. The forecast used by Overland is the best available basis for determining the cost of service components underlying the rates adopted in the GA II Settlement.

California utilizes a three year cycle for general rate cases. Under that cycle a 2012 GRC is followed by a 2015 GRC. If a 2015 GRC is settled with no change in rates compared to the prior 2012 GRC, that does not mean the rates adopted in the 2015 GRC settlement are based on the cost-of-service components that were adopted in the 2012 GRC. Settling a 2015 GRC under those terms simply means that the utility's pre-existing rates provide the utility with a fair opportunity to recover the current cost of providing service in 2015.

Q. Please provide an example of how the 1996 test year forecast did not reflect the realities of PG&E's GT&S system in 2003.

A. PG&E completed a project to increase the capacity of the Redwood path from 1,830 Mdth/d to 2,040 Mdth/d in September 2002.[60] The rates adopted in the Gas Accord I Settlement were based on a Redwood path capacity of 1,830 Mdth/d.[61] Using a seven year old forecast for a system with a Redwood path capacity of 1,830 Mdth/d to set rates for a system with a Redwood Path capacity of 2,040 Mdth/d is not a valid approach.

[60] PG&E January 2003 capital expenditures workpapers in the 2004 GT&S Rate Case, page 25, Line 401 Capacity Loops project .

[61] GA I Settlement, page 17.

Section 7

2003 Adopted Capital Expenditures

Q. Have you prepared a table that compares Overland adopted 2003 capital expenditures to Mr. O'Loughlin's adopted 2003 capex?

A. Yes The following table provides that comparison.

Table 7-1 2003 Adopted Capital Expenditures Overland Compared to O'Loughlin Dollars in Thousands	
Description	Amount
Overland Adopted Capital Expenditures	99,908
O'Loughlin Adopted Capital Expenditures	56,200
Difference	43,708
Sources: Overland Revised Table 4-1 and Exhibit___(MPO-1), page 43, Figure 10.	

Q. What caused the difference?

A. The difference reflects the same fundamental disagreement described in Section 6 concerning the correct basis for determining 2003 adopted capital expenditures. Mr. O'Loughlin treated 2003 as an extension of the GA I Settlement and rolled his GA I net plant escalation calculations forward through 2003. Overland set 2003 adopted capital expenditures equal to the 2003 forecast adopted in the 2004 Test Year GT&S rate case.

Q. Have you prepared a table that shows Mr. O'Loughlin's calculations?

A. Yes. The following table shows the calculation of the 2003 adopted capital expenditures recommended by Mr. O'Loughlin.

Table 7-2 GA II Adopted Capital Expenditures O'Loughlin Methodology - As Distilled by Overland Dollars in Thousands	
Description	2003
Net Plant - Year End	1,134,810
Beginning Net Plant	1,139,548
Increase in Net Plant	(4,738)
2003 Depreciation Expense	60,984
Rounding	(1)
Total 2003 Capex Per MPO	56,245
Source: MPO Workpapers, pages 136	

Q. How did Mr. O'Loughlin calculate the 2003 ending net plant balance.

A. Mr. O'Loughlin set the 2003 "mid" net plant balance equal to the 2002 mid net plant balance. The 2002 year end balance was available from his GA I calculations. The year end 2003 net plant balance was calculated using those two values and the following formula.

2003 Average Net Plant = [2002 YE Net Plant + 2003 YE Net Plant]/2

That converts to:

2003 YE Net Plant/2 = 2003 Average Net Plant - [2002 YE Net Plant/2]

That converts to:

Table 7-3
GA II Adopted Capital Expenditures
O'Loughlin Calculation of 2003 Ending Net Plant
Dollars in Thousands

Description	Amount
Average 2003 Net Plant	1,137,179
Less: Half of 2002 YE Net Plant	(569,774)
Subtotal	567,405
Conversion Factor	2
2003 YE Net Plant Per MPO	1,134,810

Source: MPO Workpapers, pages 135 and 136

Q. What is the basis for Mr. O'Loughlin's approach?

A. He observes that the GA II Settlement froze 2003 rates at the levels adopted for 2002 in the GA I Settlement. He set 2003 average net plant equal to his 2002 value "to be consistent with the Gas Accord I Extension settlement."[62]

Q. Do you agree with Mr. O'Loughlin's approach?

A. No. Mr. O'Loughlin's approach is invalid for the reasons explained in Section 6. The decisions to propose, agree upon and approve the rates established by the GA II settlement were based on the decision makers' perceptions of the current (2003) cost of providing service.

[62] Exhibit __(MPO-4), page 6.

Imputing 2003 adopted capital expenditures based on the 1996 GA I Settlement is not a valid approach. The 2003 forecasts from the 2004 Test Year GT&S rate case are the best available basis for determining the current cost of service components included in the GA II Settlement rates.

Q. Mr. O'Loughlin's net plant escalation approach makes the critical assumptions that net plant and depreciation expense escalate at the same rate as overall revenue requirements. Are those assumptions valid?

A. No. Mr. O'Loughlin's assumed escalation rates for net plant and depreciation expense are not valid for the reasons stated in Sections 4 and 5. However, that finding is much less significant than my fundamental disagreement with Mr. O'Loughlin's decision to use 1996 adopted net plant and depreciation expense as the starting point for his 2003 adopted capital expenditures.

Q. Mr. O'Loughlin assumed steadily declining depreciation rates during the GA I period. Did he also assume depreciation rates would decline between 2002 and 2003?

A. Yes. Mr. O'Loughlin assumes that 2003 adopted depreciation expense is exactly equal to his 2002 adopted depreciation expense . That assumption is inconsistent with his adopted gross plant values. He assumes mid-year gross plant of $2.146 billion in 2002 and $2.192 billion in 2003.[63] His adopted 2003 depreciation expense should be higher than his adopted 2002 depreciation expense because his 2003 average gross plant is higher than his 2002 average gross plant.

Q. Mr. O'Loughlin claims that Overland's approach is inconsistent with the GA II Settlement and relies on a forecast that post dates the Settlement. What is your reaction to those claims?

A. Overland's approach is consistent with the GA II Settlement for the reasons discussed in Section 6. The 2003 capital expenditures forecast adopted in the 2004 Test Year GT&S rate case is the best available basis for determining the capital expenditures included in the GA II Settlement rates. The 2003 capital expenditures adopted in the 2004 Test Year Rate Case are representative of the realities of PG&E's GT&S operations as they existed when the GA II settlement rates were proposed, agreed upon and approved.

[63] MPO Workpaper pages 134 and 135.

Q. Did the forecast that Overland relied on have a significant impact on customer rates in 2004?

A. Yes. The 2003 capital expenditures adopted in the 2004 Test Year rate case were included in rates for a full twelve months in 2004. The 2003 capital expenditures forecast adopted in the 2004 Test Year rate case was $99.9 million. Actual 2003 capital expenditures were only $89 million. As a result, the rates that PG&E charged in 2004 reflected 2003 capital expenditures that were about $11 million higher than actual 2003 capital expenditures. That shortfall was made worse by an additional $61 million shortfall in current 2004 test year capital expenditures.[64]

Q. Does Mr. O'Loughlin's approach ignore the representations that PG&E made in the 2004 Test Year GT&S rate case about its spending plans for 2003?

A. Yes. The 2003 capital expenditures forecast that PG&E filed in 2004 Test Year Rate Case is the only detailed forecast for that year contained in the record of the Gas Accord cases. Relying on a detailed forecast to established adopted capital expenditures is preferable because it allows the Commission to compare actual expenditures to the representations that PG&E made in GT&S rate cases.

PG&E's January 13, 2003 testimony in the 2004 Test Year Rate Case indicated that PG&E planned to spend $108 million on capital expenditures in 2003.[65] Mr. O'Loughlin ignores that representation and sets the standard for judging PG&E's 2003 spending at the much lower amount of $56 million. Under Mr. O'Loughlin's approach, the representations that PG&E made to the Commission and the parties in the 2004 Test Year Rate Case concerning 2003 capital expenditures are essentially meaningless.

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[64] Overland Revised Table 4-1.

[65] OC-2. PG&E Chapter 10, page 10-5. Overland's adopted 2003 capital expenditures are lower because they reflect the 2003 capital expenditures actually adopted in the 2004 Test Year Rate Case. Overland workpaper 4-7.

Section 8

2005 to 2007 Adopted Capital Expenditures

Q. Are there any significant differences pertaining to GA III adopted capital expenditures?

A. Yes. The following table compares the 2005 through 2007 adopted capital expenditures recommended by Mr. O'Loughlin and Overland.

Table 8-1
Comparison of Adopted Capital Expenditures
Overland Revised Compared to O'Loughlin - GA III Period
2005 to 2007
Dollars in Thousands

Year	Overland	O'Loughlin	Difference
2005	111,289	113,669	(2,380)
2006	113,392	115,731	(2,339)
2007	153,045	106,853	46,192
Total	377,726	336,253	41,473

Source: Overland Revised Table 4-1 and MPO Workpapers 134 to 137

Q. What caused the difference in 2005?

A. Overland excluded MWC 80, Computer Network Facility & Equipment, from its adopted capital expenditures.[66] Mr. O'Loughlin included $2.38 million in his adopted 2005 capital expenditures for MWC 80.[67]

Q. Why did Overland exclude MWC 80 from its adopted 2005 capital expenditures?

A. Overland excluded MWC 80 from its adopted 2005 capital expenditures to match the treatment of MWC 80 in the actual capital expenditures used in the comparison of adopted and actual capex. Overland's actual capital expenditures were taken from the response to discovery request OC-38. That response did not include MWC 80. The adopted and actual expenditures included in the comparison must have the same scope to provide a valid comparison. Overland excluded MWC 80 from the adopted capital expenditures to match the scope of the actual capital expenditures used in the comparison.

[66] Overland workpaper 4-9.

[67] Exhibit __ (MPO-1), page 59.

Q. Why was MWC 80 excluded from the response to OC-38?

A. OC-38 reported the capital expenditures for PG&E's GT&S business unit. PG&E consolidated its information technology function in a new IT line of business unit in 2005. During 2005 and subsequent years, the MWC 80 costs that were previously directly assigned to the GT&S business unit were charged to the new IT business unit.[68] The GT&S costs that were charged to the new IT business unit were not included in the response to OC-38. PG&E's response to OCHP-35 confirms that MWC 80 costs were excluded from the response to OC-38 after 2004.

Q. Did Mr. O'Loughlin adjust the actual capital expenditures used in his comparison to include MWC 80 costs?

A. No. The scope of his adopted capital expenditures for 2005 to 2007 does not match the scope of the actual capital expenditures included in his comparison.

Q. Why did Mr. O'Loughlin include MWC 80 in his adopted capital expenditures?

A. Mr. O'Loughlin notes that the 2005 capital expenditures adopted in the GA III settlement included MWC 80. His testimony states "I include MWC 80 in my imputed adopted amount for 2005 because this capex is explicitly recorded in the GA III workpapers."[69]

Overland agrees MWC 80 was included in the 2005 capital expenditures amounts adopted in the GA III Settlement. However, MWC 80 was clearly excluded from the actual capex amounts provided in the response to OC-38 and that response is the source for the actual capital expenditures used in the comparison. Therefore, MWC 80 costs should be excluded from the GA III adopted capital expenditures. Including MWC 80 costs in one side of the comparison, while excluding them from the other side, produces an invalid comparison.

Q. What caused the difference in adopted capital expenditures in 2006?

A. The adopted capital expenditures amounts are the products of different methodologies. Overland's revised 2006 capital expenditures equal its 2005 adopted capital

[68] OCHP-34.

[69] Exhibit__(MPO-1), page 51.

expenditures escalated at a rate of 1.89 percent. Mr. O'Louglin used his net plant escalation approach to calculate 2006 adopted capital expenditures.[70]

Although the methods were different, the MWC 80 issue logically accounts for most of the difference. Overland excluded $2.38 million in MWC 80 costs from the 2005 adopted amount. After applying the escalation factor, the 2006 MWC 80 exclusion is $2.42 million.

Q. Why did you escalate capital expenditures in 2006 instead of using a detailed forecast for 2006?

A. The GA III settlement evolved from a PG&E application that addressed a single test year, 2005. PG&E did not provide any information concerning the cost of providing service in the years 2006 and 2007 with its Application. The record in the GA III Settlement proceeding does not contain any detailed forecasts of the costs of providing service in 2006 and 2007. The revenue requirements adopted in the GA III Settlement increased at an annual rate of 1.89 percent in 2006. Overland accepted that growth rate as a conservative, but plausible, growth rate for capital expenditures. Overland's 2006 capital expenditures escalation rate had a very limited impact because it only applied to one year.

Q. What produces the large difference in 2007?

A. Mr. O'Loughlin and Overland used fundamentally different approaches to determining the 2007 adopted capital expenditure amounts. Mr. O'Loughlin used his net plant escalation approach. Overland's 2007 adopted capital expenditures were taken directly from the 2007 detailed forecast that PG&E filed in March 2007 in the GA IV Settlement proceeding.[71]

Q. Have you prepared tables showing Mr. O'Loughlin's calculations for 2007?

A. Yes. Mr. O'Loughlin assumed that his adopted 2005 depreciation expense and mid-year net plant amounts would escalate to 2006 and 2007 at the 1.89 percent growth rate in total revenue requirements adopted in the GA III Settlement. The following table summarizes Mr. O'Loughlin's calculations.

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[70] Mr. O'Loughlin used the same methodology for 2006 that he used for 2007.

[71] The forecast of 2007 capital expenditures was part of PG&E's March 2007 "litigation forecast."

Table 8-2 Adopted 2006 and 2007 Capital Expenditures As Calculated by O'Loughlin Dollars in Thousands		
Description	2006	2007
Net Plant - Year End	1,690,370	1,712,371
Beginning Net Plant	1,657,916	1,690,370
Increase in Net Plant	32,454	22,001
Depreciation Expense	83,277	84,852
Adopted Capex Per MPO	115,731	106,853
Source: MPO workpaper pages 136 and 137		

Mr. O'Loughlin used his black box "Excel Solver" smoothing methodology to convert the mid-year net plant amounts into year-end net plant amounts. However, his smoothing methodology only had a relatively small impact on 2006 and 2007 capital expenditures since his year-end amounts for 2005, 2006 and 2007 are close to the simple average of the current and subsequent year mid-year amounts.[72]

Q. Mr. O'Loughlin relies on three pages from the GA III Settlement workpapers to support his position that adopted net plant and depreciation expense should be escalated at the overall growth rate in revenue requirements adopted in the GA III Settlement. What is your response to that testimony?

A. The three rate design workpapers cited by Mr. O'Loughlin do not show net plant or depreciation expense.[73] The workpapers include a single line for rate base that shows a total rate base amount for seven backbone transmission rate categories and storage. With the exception of the G-XF rate category, the rate base amounts increase at an annual rate of 2.0 percent in 2006 and 2007. The rate design schedules do not include local transmission.

The rate base amounts shown on the rate design schedules do not have any impact on the total adopted revenue requirements for GT&S or the revenue requirements for the individual rate categories. The revenue requirements must, and do, escalate at the 2 percent growth rate negotiated in the GA III Settlement.[74] The rate base amounts shown

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[72] The mid-year 2005 amount represents June 30, 2005. The mid-year 2006 amount represents June 30, 2006. The average of those two points in time approximates December 31, 2005.

[73] The three rate design workpapers are contained on page 21, 22 and 23 of Exhibit_ (MPO-10).

[74] With the exception of G-XF revenue requirements.

on the three rate design workpapers are superfluous and should not be construed as adopting a specific net plant amount for 2006 or 2007.

Q. Why did Overland use the 2007 forecast from the GA IV proceeding to determine adopted 2007 capital expenditures?

A. Overland used that forecast to determine 2007 adopted capital expenditures because it had a significant impact on rates during 2008 through 2010 and was the only available detailed forecast for 2007.[75]

Q. Why did the litigation forecast of 2007 capital expenditures have a significant impact on rates in 2008 to 2010?

A. The March 15, 2007 GA IV Settlement covered the rate years 2008 to 2010. PG&E did not file a rate application for any of those years. Instead, the parties agreed to the GA IV Settlement without the benefit of a rate application. PG&E submitted a "litigation forecast" to support the GA IV Settlement with its March 2007 application for approval of the settlement. The litigation forecast included annual forecasts for 2007, 2008, 2009 and 2010.

The litigation forecast represented PG&E's negotiating position in the process that resulted in the GA IV Settlement. The other parties considered PG&E's litigation forecast when developing their negotiating positions and the Commission considered the litigation forecast when it approved the settlement. The record in the GA IV case does not identify any adjustments to PG&E's 2007 capital expenditures forecast.

The 2007 capital expenditures forecast was used to determine the 2008 beginning plant balances that were fully included in the litigation forecast rate base for all three years. PG&E expected the rates adopted in the GA IV Settlement to fully recover the revenue requirements produced by the litigation forecast. Actual revenues exceeded PG&E's expectations. Based on those facts, it is reasonable to conclude that the 2007 capital expenditures forecast was fully included in rates for all 36 months of the GA IV settlement period.

[75] Overland Report, page 2-10.

Section 9 includes a more detailed explanation of the reasons why PG&E's March 2007 litigation forecast had a significant impact on rates during the GA IV period.

Q. You indicated that PG&E's March 2007 litigation forecast included the only available detailed forecast of 2007 capital expenditures. What is the significance of that observation?

A. Relying on a detailed forecast to establish adopted capital expenditures is preferable because it allows the Commission to compare actual expenditures to the representations made by PG&E in GT&S rate cases. The testimony that PG&E submitted in the GA IV Settlement proceedings does not indicate that PG&E planned to slash its 2007 capital expenditures if the GA IV Settlement was adopted. Presumably, the completion of the projects included in the litigation capital expenditures forecast was not contingent on the CPUC rejecting the GA IV Settlement and adopting higher rates.

In contrast, Mr. O'Loughlin's approach does not provide any visibility into the components of adopted capital expenditures. His approach produces a single number, adopted capex, without any detail concerning the projects included in adopted capex. He does not attempt to look at the accuracy of the representations that PG&E made to the CPUC in March 2007 when it submitted its litigation forecast of capital expenditures.

Q. Did the 2007 forecast reflect PG&E's real plans for 2007?

A. Yes. Actual 2007 capital expenditures were very close to the 2007 litigation forecast. As shown on Table 4-1 of the Overland Report, actual 2007 capital expenditures were $158 million in 2007 compared to the litigation forecast of $153 million. Actual capital expenditures were 3.5 percent higher than the litigation forecast.

Q. Is setting 2007 adopted capital expenditures equal to PG&E's litigation forecast fair to PG&E?

A. Yes. Comparing PG&E's litigation forecast to actual 2007 capital expenditures is fair to PG&E because the litigation forecast presumably reflected PG&E's real plans for 2007 capital expenditures.

Q. On page 52 of his testimony, Mr. O'Loughlin claims that Overland used the 2007 litigation forecast as a proxy for the expectations of the parties to the August 2004 GA III Settlement. Did Overland do that?

A. No. The Overland Report states the basis for using the 2007 litigation forecast on page 2-10. Overland's stated basis does not reference, in any form, the expectations of the parties to the GA III Settlement. Mr. O'Loughlin's description of Overland's stated basis is highly inaccurate.

Section 9

2008 to 2010 Adopted Functional O&M Expenses

Q. Have you prepared a table that shows the remaining differences in adopted functional O&M expenses during the GA IV period?

A. Yes. The following table shows those differences for 2008, 2009 and 2010.

Table 9-1
Comparison of Adopted O&M Expenses
Overland Compared to O'Loughlin
GA IV Period - 2008 to 2010
Dollars in Thousands

YEAR	Overland	O'Loughlin	Difference
2008	85,498	80,400	5,098
2009	87,101	80,500	6,601
2010	85,916	80,600	5,316
Total	258,515	241,500	17,015

Sources: Overland Revised Table 3-1 and Exhibit__(MPO-1) page 39

Q. What issues account for the differences in adopted O&M for the GA IV period?

A. The differences result from a fundamental disagreement about the correct basis for determining 2008 to 2010 adopted O&M expenses. Overland's adopted O&M amounts reflect the O&M forecasts contained in PG&E's March 2007 litigation forecast.[76]

Mr. O'Loughlin calculated adopted O&M by escalating his adopted value for 2007 at the overall growth rates in the total GT&S revenue requirements adopted in the GA IV Settlement, excluding the adopted revenue requirements for the local transmission adder projects.[77]

Overland Adopted O&M

Q. Why did Overland use PG&E's March 2007 litigation forecast to determine adopted O&M during the GA IV period?

[76] PG&E's March 2007 litigation forecast was provided to the parties during the GA IV Settlement negotiations and submitted to the CPUC with PG&E's Application for Approval of the GA IV Settlement.

[77] The GA IV settlement adopted separate contingent rate surcharges for five local transmission construction projects that were expected to be completed during the settlement period. The shorthand title for those projects is "the local transmission adder projects."

A. Overland used the litigation forecast for two reasons. First, PG&E's litigation forecast is the best available basis for determining the cost-of-service components included in the rates adopted in the GA IV Settlement Agreement. Second, PG&E's litigation forecast is the only available detailed forecast of O&M expenses for the GA IV period.

Q. Why is PG&E's March 2007 litigation forecast the best available basis for determining the cost of service components included in the GA IV Settlement rates?

A. The litigation forecast was the basis for PG&E's negotiating position. PG&E provided the litigation forecast, and the supporting O&M workpapers, to the parties during the settlement negotiations and the parties considered that information when forming their negotiating positions.

PG&E included the litigation forecast in the testimony it submitted with its March 2007 application for approval of the settlement. The Commission considered the litigation forecast when it approved the GA IV Settlement. The record in the GA IV Settlement case does not identify any adjustments to PG&E's O&M and capital expenditures forecasts.

PG&E expected the GA IV Settlement rates to fully recover the revenue requirements produced by its litigation forecast. Actual revenues exceeded those expectations. Based on those facts, it is reasonable to conclude that the rates adopted in the GA IV Settlement were sufficient to fully recover the O&M expenses and capital expenditures included in PG&E's March 2007 litigation forecast.

Q. Did PG&E's own internal analysis show that the rates adopted in the GA IV Settlement were sufficient to fully recover the revenue requirements produced by PG&E's March 2007 litigation forecast?

A. Yes. PG&E expected the rates adopted in the GA IV Settlement to fully recover the litigation forecast revenue requirement. PG&E prepared an internal forecast of the revenues that it expected the settlement rates to produce on March 6, 2007.[78] The forecasted revenues exceed the litigation forecast revenue requirement by $48 million over the three year GA IV period, as shown below.

[78] OC-84, Attachment 2. The analysis is dated March 6, 2007.

Table 9-2 Gas Accord IV Settlement Revenues Expected by PG&E Compared to Litigation Forecast RRQ 2008 to 2010 Dollars in Millions				
Description	2008	2009	2010	Total
PG&E Forecast with Settlement Rates	476.4	500.9	521.7	1,499.0
Litigation Forecast Revenue Requirement	457.2	483.9	510.1	1,451.2
Difference	19.2	17.0	11.6	47.8
Source: OC-84, Attachment 2				

The rates adopted in the GA IV Settlement were more than sufficient to recover PG&E's litigation forecast revenue requirements and PG&E was aware of that when the GA IV Settlement Agreement was submitted to the Commission on March 15, 2007. Using PG&E's litigation forecast as the basis for determining adopted O&M and capital expenditures reflects the substance of the cost recovery produced by the GA IV Settlement rates.

Q. Did PG&E also expect the GA IV Settlement rates to produce revenues that significantly exceeded the adopted revenue requirements shown in the Settlement Agreement?

A. Yes. PG&E expected the GA IV Settlement rates to produce revenues that exceeded the revenue requirements shown on Appendix A, Table A-4 of the Settlement Agreement by $122 million over the three year settlement period. [79]

Q. Has PG&E admitted that it expected the settlement rates to fully recover the litigation forecast revenue requirement?

A. Yes. Discovery question OCHP-25 asked PG&E to explain why it expected the settlement rates to produce revenues that exceeded the litigation forecast revenue requirement. The response indicates:

> ...PG&E negotiated a settlement that, on the whole, provided a reasonable opportunity to achieve revenues that equaled the forecasted revenue requirement. PG&E tested the final settlement rates in its revenue forecasting models and determined that the backbone transmission and local transmission functions were likely to under-perform while the storage function was likely to over-perform. On the whole, PG&E expected the GT&S business to slightly over-perform.

[79] OC-84, Attachment 2, and Appendix A, Table A-4 of the Settlement. See also, PG&E testimony supporting the settlement, pages 12 and 17.

PG&E's March 2007 expectations were realistic. Actual revenues were higher than the revenues that PG&E forecasted in its March 2007 internal analysis of the GA IV Settlement. Actual revenues were $65.5 million higher than the litigation forecast revenue requirement for the three year GA IV period, as shown in the following table.

Table 9-3
Gas Accord IV Settlement
Actual Revenues Compared to Litigation Forecast Revenue Requirement
2008 to 2010
Dollars in Millions

Description	2008	2009	2010	Total
Actual GT&S Revenues (Revised Table 5-3)	498.8	515.0	508.3	1,522.1
Less: Storage Carrying Charge Revenue	(1.8)	(1.8)	(1.8)	(5.4)
Actual Revenues for Comparison	497.0	513.2	506.5	1,516.7
Litigation Forecast Revenue Requirement	457.2	483.9	510.1	1,451.2
Difference	39.8	29.3	(3.6)	65.5

Note: Storage Carrying Charge Revenues are deducted from actual revenues because they were not included in the Litigation Revenue Requirement.

Source: OC-84, Attachment 2 and Overland Revised Table 5-3

Actual revenues exceeded the litigation forecast revenue requirement despite the fact that some of the local transmission adder projects included in the litigation forecast were not included in rates during the three year period.

Q. Did actual revenues also exceed the revenue requirements adopted in the GA IV Settlement?

A. Yes, actual 2008 to 2010 revenues exceeded the revenue requirements adopted in the GA IV Settlement by $137 million. Actual revenues exceeded the adopted revenue requirements by ten percent during the GA IV period, as shown below.

Table 9-4
Comparison of Actual and Adopted Revenue
GA IV Period - 2008 to 2010
Dollars in Thousands

Year	Actual	Adopted	Difference	Percent
2008	498,851	449,415	49,436	11.0
2009	515,034	461,819	53,215	11.5
2010	508,324	474,266	34,058	7.2
Total	1,522,209	1,385,500	136,709	9.9

Source: Overland Revised Table 5-3. Percent is Difference divided by Adopted.
Adopted includes Adder Projects From Settlement Table A-2

The actual return on equity earned by PG&E's GT&S operations also significantly exceeded the authorized level throughout the GA IV period.[80] PG&E expected the Settlement rates to produce significantly more revenues than the revenue requirements specified in the settlement when it entered into the settlement in March 2007. The actual results produced by the settlement rates show that expectation was very achievable.

Q. You indicated that PG&E's litigation forecast was the only available detailed forecast of 2008, 2009 and 2010 O&M. What is the significance of that statement?

A. PG&E's March 2007 testimony included a detailed description of the methodology used to develop the forecast, including the O&M and capital expenditures forecasts. PG&E submitted O&M and capital expenditures workpapers to support the litigation forecast. Those workpapers included the same level of detail as the workpapers PG&E submitted with its applications in the 2004 Test Year GT&S rate case and the GA III case.[81]

The litigation forecast was a fully developed detailed forecast for 2008, 2009 and 2010. The litigation forecast presumably reflected PG&E's actual plans for its GT&S operations for those years. The litigation forecast was the product of a significant internal effort by PG&E and was presumably fully vetted prior to distribution to the parties and submission to the CPUC.

PG&E's testimony shows that the revenue requirement produced by the litigation forecast was higher than the revenue requirements adopted in the Settlement.[82] PG&E's Application and testimony do not state that it would reduce its O&M expenditures below the levels shown in the litigation forecast if the GA IV Settlement was adopted.

The litigation forecast presumably reflected PG&E's actual plans for its GT&S operations for the years 2008, 2009 and 2010. The litigation forecast was provided to the parties and the CPUC prior to approval of the settlement. The litigation O&M forecast provides a basis for tracking PG&E's performance relative to the representations that it made in the GA IV proceeding.

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[80] Overland Revised Table 5-1.

[81] The workpapers submitted in the GA III case only covered the rate year 2005.

[82] PG&E Testimony Supporting the Gas Accord IV Settlement, page 18.

In contrast, Mr. O'Loughlin's approach produces a single number for O&M. Mr. O'Loughlin's approach does not provide any visibility into the whether PG&E followed through on the plans that it submitted to the CPUC in the GA IV proceeding.

O'Loughlin Adopted O&M

Q. Have you prepared tables showing Mr. O'Loughlin's calculations?

A. Yes. The first table shows the calculation of Mr. O'Loughlin's O&M escalation factors.

Table 9-5
O'Loughlin O&M Escalation Factors
2008 to 2010
Dollars in Thousands

Description	2007	2008	2009	2010
Total Revenue Requirement - Table A-4	443,688	446,493	458,875	471,299
Less: Transmission Adders - Table A-4	0	0	(11,981)	(23,963)
Net Revenue Requirement	443,688	446,493	446,894	447,336
Current Year Divided by Prior Year	NA	1.0063	1.0009	1.0010
Source: GA IV Settlement Table A-2 and Exhibit__(MPO-1) page 32				

The second table shows the calculation of his adopted functional O&M amounts.

Table 9-6
O'Loughlin Adopted O&M
2008 to 2010
Dollars in Thousands

Description	2008	2009	2010
Prior Year Functional O&M	79,900	80,405	80,477
Escalation Factor	1.0063	1.0009	1.0010
Current Year Functional O&M	80,405	80,477	80,557
Rounding	(5)	23	43
Adopted O&M Per MPO	80,400	80,500	80,600
Source: Table 9-5 and Exhibit__(MPO-1), page 39. Excludes Customer Accounts and Sales Expense			

Q. Is Mr. O'Loughlin's approach reasonable?

A. No. Mr. O'Loughlin's adopted O&M amounts were calculated by escalating his adopted 2007 O&M amounts through 2010 based on the overall growth rates in revenue requirements adopted in the settlement. His 2007 adopted O&M was calculated by escalating 2005 O&M through 2007 using the same approach. Mr. O'Loughlin's adopted O&M amounts for 2006 through 2010 are all based on adopted O&M for the year 2005, and reflect PG&E's plans for the year 2005. Mr. O'Loughlin's adopted O&M amounts for

2008, 2009 and 2010 cannot, and do not, reflect PG&E's actual plans for its GT&S operations in those years.

Q. Does Mr. O'Loughlin admit that the GA IV settlement does not contain any support for his contention that O&M expenses grow at the same rate as the total revenue requirement?

A. Yes. On page 45 of his testimony, Mr. O'Loughlin admits "there are no workpapers in which the escalation factors for the individual elements of the [GA IV] revenue requirement are specified." He simply assumes that O&M grows at the same rate as total revenue requirements based on his interpretation of prior Gas Accord settlements.[83]

Q. Is Mr. O'Loughlin's assumption consistent with the GA IV Settlement Agreement?

A. No. Sections 8.1 and 8.2 of the Settlement Agreement show significantly different escalation rates for the numerous customer rates adopted in the GA IV settlement. The following table shows those escalation rates.

Table 9-7
Gas Accord IV Settlement
Revenue Requirements Escalation Rates
Annual Percentage Change By Function and Path
Years 2008 to 2010

Function/Path	2008	2009	2010
Backbone - Redwood Core Vintage	(9.6)	(1.0)	(1.0)
Backbone - Redwood Noncore	(4.4)	(1.0)	(1.0)
Backbone -Baja	5.8	(1.0)	(1.0)
Backbone - Silverado and Mission	(1.0)	(1.0)	(1.0)
Backbone - G-XF	(4.2)	(1.2)	(1.8)
Local Transmission	4.0	2.0	2.0
Core Storage	0.0	0.0	0.0
Customer Access Charge	0.0	0.0	0.0

Source: Sections 8.1 and 8.2 of Settlement Agreement. Local Transmission Excludes LT plant adders. G-XF rates are from Settlement Appendix A, Table A-4.

The variation in the escalation rates between functions and paths demonstrates that general inflation in current expenditures and organization wide productivity

[83] Exhibit___(MPO-1), page 45.

improvements were not driving a uniform rate of increase in all elements of the cost of service.

Q. Do the local transmission adder projects illustrate the problems with Mr. O'Loughlin's key assumption?

A. Yes. Mr. O'Loughlin escalates O&M at annual rates of 0.6 percent in 2008 and 0.1 percent in 2009 and 2010. Including the revenue requirements for the local transmission adder projects in Mr. O'Loughlin's calculations would significantly change his escalation factors and adopted O&M in 2009 and 2010, as shown below.

Table 9-8
Gas Accord IV Settlement
O'Loughlin Escalation Factor - Revised to Include LT Adders
2008 to 2010
Dollars in Thousands Unless Indicated Otherwise

Description	2007	2008	2009	2010
Adopted Revenue Requirement with LT Adders	443,688	446,493	458,875	471,299
Escalation Factor - Including LT Adders	NA	0.6	2.8	2.7
MPO O&M With Revised Escalation ($ Millions)	79.9	80.4	82.6	84.9
Adopted O&M per MPO ($ Millions)	79.9	80.4	80.5	80.6
Difference ($ Millions)	0.0	0.0	2.2	4.3
Source: GA IV Settlement, Appendix A, Table A-4 and Exhibit___(MPO-1), page 39.				
Note: MPO Adopted O&M is functional O&M excluding Customer Accounts and Sales Expense				

If the GA IV Settlement had included the local transmission projects in the base local transmission revenue requirement instead of in a separate contingent rate, Mr. O'Loughlin's methodology would have produced adopted 2010 O&M that was $4.3 million higher than his current amount.

Adopted O&M should not depend on whether the parties agree to a separate contingent rate adder for selected construction projects. The rate at which adopted O&M expenses escalate is the same, regardless of the form of the rate mechanism used to recover the revenue requirements of local transmission construction projects.

Q. Overland used total revenue requirements to escalate O&M in 1997 to 2002 and in 2006 and 2007. How are your criticisms of Mr. O'Loughlin's approach consistent with that?

A. As the Commission noted in the GA I Decision, some elements of cost of service are subject to inflation while others are not. For that reason, total revenue requirement growth is not the preferred basis for escalating current expenditures such as O&M and capital expenditures. Overland only used total revenue requirements growth to escalate adopted O&M in years in which a detailed forecast was not available.[84]

The preferred approach is to use a detailed forecast of current expenditures, when such forecasts are available for the applicable rate years. The litigation forecast included a detailed forecast for 2008, 2009 and 2010 and those forecasts should be used to determine adopted O&M for those years.

When a detailed forecast is not available, the rate of growth in total revenue requirements can be used, if it is a plausible approximation of the growth rate in O&M expenses based on all of the facts and circumstances of the rate year. When a detailed forecast is not available, the selection of an O&M escalation factor requires professional judgment.

Q. Mr. O'Loughlin used O&M escalation rates of 0.1 percent in 2009 and 2010. Are those plausible approximations of the O&M growth rate embedded in GA IV period rates?

A. No.

[84] Those years were 1997 through 2002 and 2006 and 2007.

Section 10

2008 to 2010 Adopted Capital Expenditures

Q. Have you prepared a table showing the remaining differences in adopted capital expenditures for the GA IV period?

A. Yes. The following table shows those differences.

Table 10-1
Comparison of Adopted Capital Expenditures
Overland Compared to O'Loughlin
GA IV Period - 2008 to 2010
Dollars in Thousands

YEAR	Overland	O'Loughlin	Difference
2008	221,970	89,700	132,270
2009	249,969	158,200	91,769
2010	190,260	87,400	102,860
Total	662,199	335,300	326,899
Sources: Overland Report Table 4-1 and Exhibit__(MPO-1) page 43			

Q. What caused the large differences in adopted capital expenditures during the GA IV period?

A. The differences were caused by fundamental disagreements about the correct basis for determining adopted capital expenditures in 2008 to 2010. Overland's adopted capital additions for 2008 and 2009 were taken from PG&E's March 2007 litigation forecast. Overland's 2010 capital additions were taken from PG&E's March 2010 capital expenditures workpapers in the 2011 GT&S rate case.

Mr. O'Loughlin used his net plant escalation approach. The starting points for his calculations are his 2007 adopted net plant and depreciation expense values. He escalated those 2007 values through 2010 at the same growth rate as the total revenue requirements adopted in the GA IV Settlement, excluding local transmission plant adders. He used those escalated values to calculate adopted capital expenditures and added $71.6 million to the result for 2009 for the local transmission adders.

2008 and 2009 Adopted Capital Expenditures

Q. Why did Overland take its 2008 and 2009 adopted capital expenditures from PG&E's March 2007 litigation forecast?

A. Overland used PG&E's March 2007 litigation forecast as the basis for its adopted 2008 and 2009 capital expenditures for two reasons. First, PG&E's litigation forecast is the best available basis for determining the cost-of-service components included in the 2008 and 2009 rates adopted in the GA IV Settlement Agreement. Second, PG&E's litigation forecast provided the only available detailed capital expenditures forecasts for those years.

As I explained previously in Section 9, the litigation forecast had a significant impact on the rates adopted in the GA IV forecast. The litigation forecast formed the basis for PG&E's negotiating position and was considered by the parties when they formed their negotiating positions. PG&E submitted the litigation forecast, including detailed capital expenditures workpapers, with its Application for approval of the GA IV Settlement. The Commission considered the litigation forecast when it approved the Settlement.

PG&E expected the settlement rates to fully recover the revenue requirements produced by the litigation forecast. The Settlement Agreement and supporting workpapers do not identify any capital expenditure disallowances. PG&E's litigation forecast is the best available basis for determining adopted capital expenditures in 2008 and 2009.

Q. You indicated that the March 2007 litigation forecast was the only available detailed forecast for 2008 and 2009. Why is that significant?

A. Mr. O'Loughlin's approach produces a single amount for adopted capital expenditures. That amount is largely based on PG&E's plans for 2005. Mr. O'Loughlin's approach does not provide any visibility into the projects included in adopted capital expenditures. Under his approach, the Commission can only compare adopted and actual capital expenditure at a total GT&S level. His approach does not allow the Commission to compare actual spending for specific projects or categories to the representations that PG&E made when the GA IV settlement was being negotiated and approved.

PG&E submitted detailed capital expenditures workpapers to the Commission in March 2007 showing numerous specific projects planned for 2008, 2009 and 2010. Under Mr.

O'Loughlin's approach, the representations that PG&E made in those workpapers are essentially meaningless.

The testimony that PG&E submitted in the GA IV Settlement proceedings did not indicate that PG&E planned to slash its 2008 and 2009 capital expenditures if the GA IV Settlement was adopted. Presumably, the completion of the projects included in the litigation capital expenditures forecast was not contingent on the Commission rejecting the GA IV Settlement and adopting higher rates.

2010 Adopted Capital Expenditures

Q. Why did Overland use PG&E's March 2010 forecast from the 2011 GT&S rate case to determine 2010 adopted capital expenditures?

A. The following table shows PG&E's litigation forecast for 2008, 2009 and 2010.

Table 10-2
PG&E Litigation Forecast
Capital Expenditures
2008 to 2010
Dollars in Thousands

Year	Amount
2008	221,970
2009	249,969
2010	100,241

Source: PG&E capex workpapers March 15, 2007, excludes MWC 80

The 2010 forecasted capital expenditures were unusually low. The forecast subsequently proved to be highly inaccurate. Actual 2010 capital expenditures were $193 million. 2010 was the last year in a three year rate cycle. The 2010 forecast only impacted rates in a single year, and only about fifty percent of the 2010 forecast was included in rate base in that year.[85]

Overland concluded that PG&E's 2010 litigation forecast of capital expenditures was not reasonable and had a limited impact on the rates charged to customers.

[85] Rate base is a weighted average for the year. If the capital projects are included in mid-year, they are only included in rate base for six months in that year.

The GA V settlement covered the 2011 to 2014 rate years. The 2010 capital expenditures forecast adopted in the GA V settlement was used to determine the starting rate base for 2011. As such, the 2010 capital expenditures forecast was fully included in rate base in all four rate years included in the settlement.

Overland used the 2010 forecast from the 2011 GT&S case to determine 2010 adopted capital expenditures, because it had a significant ratemaking impact and was the best available detailed forecast of 2010 capital expenditures.

Q. The GA IV Settlement was negotiated in March 2007. Is using a forecast that was prepared after that time fair to PG&E?

A. Yes. The 2010 capital expenditures shown in the March 2010 forecast submitted in the GA V case were very close to actual 2010 capital expenditures. Specifically, the forecast amount was $190.3 million and the actual amount was $193.0 million. Using the capital expenditures forecast from the 2011 GT&S rate case does not create any shortfall in actual spending.

The 2010 capital expenditures forecast adopted in the 2011 GT&S rate case will be fully reflected in PG&E's rates for 48 months, on average. In contrast, the GA IV litigation forecast for 2010 was only included in rate base for six months, on average. The 2010 forecast from the 2011 GT&S rate case will have 8 times more impact on ratepayers than the GA IV litigation forecast for 2010.

Using the 2010 forecast from the 2011 GT&S rate case is fair to PG&E because it reflects the economic substance of PG&E's rate recovery of 2010 capital expenditures far better than the inaccurate litigation forecast submitted to the CPUC in March 2007.

Q. You took the 2010 adopted amounts from PG&E's March 26, 2010 capital expenditures forecast. Did the GA V Settlement adopt any adjustments to that forecast?

A. No, not for the year 2010. Section 7.2 of the GA V Settlement adopted some capital expenditures adjustments for 2011 to 2014, but did not adopt any adjustments to 2010 expenditures. The GA IV Settlement set rates for four years, 2011 through 2014. The Joint Testimony of the Settling parties includes a section on capital expenditures. That section indicates:

> The Settlement Parties successfully negotiated reductions to the capital expenditures forecast...These expenditure reductions, which are detailed in Section 7.2 of the Settlement, total $155.6 million over the four-year settlement term.

The Joint Testimony includes a table showing the reductions by year, as shown below.

Table 10-3
GA IV Settlement
Adopted Capital Expenditures Reductions
Compared to PG&E Application
Dollars in Millions

Year	Amount
2011	47.0
2012	38.6
2013	41.7
2014	28.3
Total	155.6

Source: Joint Testimony of Settlement Parties, September 20, 2010, page 7

None of the adopted $155.6 million in reductions were shown as reductions to 2010 capital expenditures.

The March 26, 2010 forecast closely tracked PG&E's actual 2010 capital expenditures. The GA IV settlement is dated August 20, 2010 and was approved on April 14, 2011. GT&S capital expenditures are concentrated in the summer and early fall months to prepare the system for the upcoming winter peak demand period. By the time the settlement was signed, PG&E had already made construction commitments for its 2010 construction program. There is no reason to believe the parties were able to negotiate an adopted level of 2010 capital expenditures that was significantly lower than PG&E's actual 2010 capital expenditures.

Q. On page 54 of his testimony, Mr. O'Loughlin claims you used the March 2010 capital expenditures forecast as a "proxy for the parties' expectations" when they entered into the March 2007 GA IV Settlement. Did you do that?

A. No. Overland's basis for using the March 2010 capital expenditures forecast is set forth on page 2-11 and 2-12 of the Overland Report. Overland's stated basis does not refer to the expectations of the parties to the March 2007 GA IV settlement. Mr. O'Loughlin's description of Overland's stated basis is highly inaccurate.

O'Loughlin Calculations

Q. Have you prepared tables that summarize Mr. O'Loughlin's calculations?

A. Yes. The following table shows the calculation of Mr. O'Loughlin's adopted net plant and depreciation expense values.

Table 10-4
GA IV Period
Adopted Net Plant and Depreciation
Per O'Loughlin
Dollars in Thousands

Description	Mid Year Net Plant	Depreciation Expense
2007 Adopted Per MPO	1,704,697	84,852
2008 Escalation Factor	1.00633	1.00633
2008 Adopted Per MPO	1,715,482	85,389
2009 Escalation Factor	1.00090	1.00090
2009 Adopted Per MPO	1,717,024	85,466
2010 Escalation Factor	1.00099	1.00099
2010 Adopted Per MPO	1,718,723	85,550
Source: MPO workpapers page 137 and GA IV Settlement Table A-4		

Mr. O'Loughlin's escalation factors are explained in Section 9. He converted the mid-year net plant values into end-of year net plant values using his black box smoothing method. The smoothing method does not have a significant impact on the values. The year-end values are very close the simple average of the current year and subsequent year mid-year values.

The following table shows how Mr. O'Loughlin calculated his adopted capital expenditures amounts from his adopted depreciation expense and year-end net plant values.

Table 10-5 GA IV Adopted Capital Expenditures Per O'Loughlin 2008 to 2010 Dollars in Thousands			
Description	2008	2009	2010
Year End Net Plant	1,716,655	1,717,794	1,719,652
Net Plant - Beginning	1,712,371	1,716,655	1,717,794
Increase in Net Plant	4,284	1,139	1,858
Depreciation Expense	85,388	85,465	85,550
Total Before LT Plant Adders	89,672	86,604	87,408
Local Transmission Plant Adders	0	71,600	0
Rounding	1	(1)	0
Total Capex per MPO	89,673	158,203	87,408
Source: MPO workpapers, page 137			

Q. Is Mr. O'Loughlin's approach valid?

A. No. The starting point for Mr. O'Loughlin's calculations are his adopted net plant and depreciation expense amounts for 2007. Those amounts were determined, in turn, by escalating his adopted 2005 net plant and depreciation expense values using the same approach.

Mr. O'Loughlin's adopted capital expenditure values for 2006 through 2010 are all based on the 2005 net plant and depreciation expense values adopted in the GA III Settlement. Those values reflected PG&E's plans for a single year, calendar year 2005. Mr. O'Loughlin's approach cannot, and does not, reflect PG&E's capital expenditure plans for 2008, 2009 and 2010, as they existed in March 2007 when the Settlement Agreement was signed.

The rate commitments made in the GA III Settlement Agreement expired on December 31, 2007. The decisions to propose, agree upon and approve the rates adopted in the GA IV Settlement were based on the decision makers perceptions of the current cost of providing service when those decisions were made, not the cost of providing service in 2005.

Q. Are Mr. O'Loughlin's adopted depreciation expense values consistent with the GA IV Settlement Agreement?

A. No. The following table shows the average depreciation rates produced by Mr. O'Loughlin's adopted depreciation expenses and mid-year gross plant values.

Table 10-6
Average Adopted Depreciation Rates
Produced by O'Loughlin Adopted Plant and Depreciation Expense
2005 to 2010
Dollars in Thousands

Year	Mid-Year Gross Plant	Depreciation Expense	Depreciation Rate
2005	2,918,339	81,732	2.80
2006	3,003,200	83,277	2.77
2007	3,090,540	84,852	2.75
2008	3,162,921	85,388	2.70
2009	3,228,558	85,465	2.65
2010	3,294,374	85,550	2.60
Source: MPO workpapers, pages 136 and 137			

Mr. O'Loughlin's average adopted depreciation rate decreases each year from 2005 to 2010. Section 8.7 of the GA IV Settlement Agreement states:

> During the term of this agreement, PG&E will continue to use the depreciation parameters used in the Gas Accord III Settlement and approved in D.04-12-050.[86]

PG&E's Application and Request for Approval of the GA IV Settlement indicates "Section 8.7 states that PG&E will not change its depreciation parameters during the settlement period." Mr. O'Loughlin's assumption that depreciation rates will decline in every year of the settlement period is inconsistent with the Settlement Agreement.

Q. Does reducing depreciation rates between rate cases harm ratepayers?

A. Yes. As explained in Section 5, reducing depreciation rates between rate cases harms ratepayers.

Local Transmission Adder Projects

Q. Mr. O'Loughlin accounted for the local transmission adder projects separately. Please explain how the local transmission adder projects were addressed in the GA IV Settlement.

A. Section 8.4 of the Settlement Agreement adopts contingent rate surcharges for five local transmission projects. The amount of the surcharge for each project was fixed in the Settlement. The settlement authorizes PG&E to implement the surcharges for each of the projects on January 1 of the year following the year in which the individual projects

[86] D.04-12-050 is the decision that approved the Gas Accord III Settlement.

were completed. Mr. O'Loughlin refers to the five projects as the "local transmission adder projects."[87]

The total adopted construction cost for each of the five projects is shown on Table A-2 of Appendix A of the Settlement Agreement. Table A-2 also shows the anticipated completion date for each project and the fixed rate surcharges to be implemented on January 1 of the year following the completion date for each project.

Q. Table A-2 shows the total capital costs for each of the five adder projects. Do you know the timing of the capital expenditures that comprise those amounts?

A. Yes. The total capital costs shown on Table A-2 agree with the capital expenditures forecast included in PG&E's March 2007 litigation forecast. Therefore, it is reasonable to conclude that the adopted capital amounts shown on Table A-2 were taken directly from the litigation forecast. The following table shows the adopted capital expenditure amounts by year.

Table 10-7
GA IV Settlement
Adopted Local Transmission Adder Projects
Plant Costs By Year of Capital Expenditure
Dollars in Thousands

Year	Line 138	Line 108	Lines 407/407	Total
2005	27	698	151	876
2006	989	1,509	775	3,273
2007	4,810	10,638	4,540	19,988
2008	32,785	20,106	9,662	62,553
2009	0	0	62,449	62,449
2010	0	0	2,897	2,897
Total	38,611	32,951	80,474	152,036

Source: PG&E's March 15, 2007 Capital Expenditures Workpapers, Table 2 and GA IV Settlement, Appendix A, Table A-2

Q. Have you prepared a table that compares Mr. O'Loughlin's adopted capital expenditures for the adder projects to actual expenditures for those projects?

A. Yes. The following table makes that comparison.

[87] Exhibit___(MPO-1), page 45, line 25

Table 10-8 GA IV Settlement Capital Expenditures Transmission Adder Projects O'Loughlin Adopted Compared to Actual Dollars in Thousands			
Year	Actual	MPO Adopted	Difference
2008	62,759	0	62,759
2009	20,044	71,600	(51,556)
2010	24,834	0	24,834
Total	107,637	71,600	36,037
Source: OCHP-23 and MPO workpapers, page 137			

Mr. O'Loughlin's adopted capital expenditures equal the total adopted plant costs for the Line 138 and Line 108 projects, as shown below.

Table 10-9 GA IV Settlement O'Loughlin Adopted LT Adder Capex By Project Dollars in Thousands	
Project	Amount
Line 138 Adopted Plant Costs	38,611
Line 108 Adopted Plant Costs	32,951
Adopted 2009 Capex Per MPO	71,562
Source: MPO workpapers, page 137. Rounding difference noted.	

Mr. O'Loughlin's 2009 adopted capital expenditures for the Line 138 and Line 108 projects actually consist of capital expenditures forecasted to occur in 2005, 2006, 2007 and 2008.

Q. The Line 108 and Line 138 projects were multi-year projects. Why did Mr. O'Loughlin put all of the adopted capital expenditures for those projects in one year?

A. As can be seen above, Mr. O'Loughin's adopted capital expenditure amounts are not actually capital expenditures amounts. Instead, they represent plant additions, with a one year lag.[88]

The difference between capital expenditures and plant additions is a matter of timing. Capital expenditures are reported in the year in which the funds are expended for construction. Plant additions are recorded in the year in which the project is placed into operations.

[88] OCHP-22. The actual completion date for the Line 108 projects was September 29, 2008. The Actual completion date for the Line 138 project was July 9, 2008.

Mr. O'Loughlin's adopted capital expenditures are the total completion cost of the project and are shown in the year that the rate surcharge for that project became effective. Mr. O'Loughlin's adopted capital expenditures amounts are not shown in the year in which PG&E expended the funds to construct the projects, or the year in which the costs of the project were added to PG&E's plant in service accounts.

Q. What was Mr. O'Loughlin's stated basis for including the entire cost of the project in capital additions in the year in which the rate surcharge was implemented?

A. Page 46 of Mr. O'Loughlin's testimony states:

> [t]he rates could only increase to recover the agreed upon additional revenue requirements associated with the adder projects after the project had gone into service. Therefore, to determine imputed adopted capital expenditures that were agreed in Gas Accord IV, I include only those adder projects [that were actually completed] in the year after they entered service...

Q. Do you agree with Mr. O'Loughlin's reasoning?

A. No. The purpose of the analysis is to compare adopted and actual capital expenditures. Plant additions always lag behind capital expenditures. Comparing adopted plant additions (with a one year lag) to actual capital expenditures produces an invalid comparison.

Q. Mr. O'Loughlin seems to be saying that capital expenditures cannot be adopted until they are placed into rates? Do you agree with that?

A. No. For multi-year projects, there is always a lag between when capital expenditures are incurred and rates are adjusted. The timing of the recognition of the adopted capital expenditures does not depend on the year in which they are included in rate base. Adopted capital expenditures are recognized in the year in which they are expended, not in the year in which they are added to rate base.

Q. Does the August 2010 GA V Settlement Agreement demonstrate that point?

A. Yes. The GA V Settlement Agreement covered the 2011 to 2014 rate years. Section 7.2 of that Agreement shows the "capital expenditures plan for the Settlement Period" by year for 2011 to 2014. The amounts included in that capital expenditures plan are the adopted capital expenditures for those years.

Section 7.2.11 is titled Capital Projects with Post-2014 In-Service Dates. That section states:

> Various projects in PG&E's capital expenditures plan have in-service dates after 2014 (e.g, the Burney K-2 replacement project). Those projects have no impact on the Settlement revenue requirement and nothing in this Settlement shall be construed as endorsement of the reasonableness and/or approval of any such project.

The projects with post-2014 completion dates, including the Burney K-2 replacement project, are included in the adopted capital expenditures plan shown in Section 7.2 of the Settlement Agreement.[89] The expenditures for those projects are shown in the year in which the expenditures are expected to occur, not the year in which the project is expected to be completed. That demonstrates: (1) adopted capital expenditures are recognized in the year that they are incurred; and (2) the recognition of adopted capital expenditures does not depend on their inclusion in rates during the settlement period.

Q. Is Mr. O'Loughlin's approach inconsistent with the approach he took for other multi-year projects?

A. Yes. For 2004, Mr. O'Loughlin's adopted capital expenditures reflect the 2004 capital expenditures adopted in the 2004 Test Year GT&S rate case. Those adopted capital expenditures include several projects that began in 2003 and were expected to be completed in 2004.[90] Mr. O'Loughlin did not include the entire completion cost of those projects in his adopted 2004 capital expenditures. Instead, he only included the amounts that were expected to be expended during calendar year 2004 in his adopted 2004 capital expenditures.

[89] The Burney K-2 Gas Turbine Replacement Project is shown on PG&E capital expenditures workpaper 6-5. PG&E expected the project to have $15.5 million in capital expenditures in 2014. PG&E's forecasted completion date for the project was December 31, 2015. The project is included in MWC 76 Station Reliability. Section 7.2 of the Settlement Agreement lists the adjustments that were made to PG&E's capital expenditures forecast to derive the adopted capital expenditures plan shown in that section. Section 7.2 does not make any adjustments to PG&E's capital expenditures forecast to exclude the Burney K-2 replacement project from the adopted capital expenditures.

[90] For example, the 2004 Test Year Decision did not adopt any adjustments to PG&E's 2004 capital expenditures forecast for MWC 12, Environmental Projects (See Overland workpaper 4-8). Page 2 of PG&E's capital expenditures workpapers for that case show the details of its MWC 12 forecast. The forecasted capital expenditures for MWC 12 include two projects with the title "Frame 3 Unit Replacement, Delevan Comp. Willows." Those projects are described on page 12 of PG&E's capital expenditure workpapers. The combined forecasted expenditures for the two projects are $5 million in 2003 and $23 million in 2004. Mr. O'Loughlin's 2004 adopted capital expenditures only include the $23 million that was forecasted for 2004.

Q. Does Mr. O'Loughlin's approach produce a mismatch when he compares his adopted amounts to actual capital expenditures?

A. Yes. His actual capital expenditures amounts are the actual amounts expended for construction projects during the current year. His "adopted capital expenditures" for the local transmission adders are plant additions, with a one-year delay. A valid comparison of actual and adopted amounts requires a comparable scope on both sides of the comparison. Mr. O'Loughlin's comparison is not valid because his adopted amounts have a different scope than his actual amounts.

Q. Mr. O'Loughlin's adopted capital expenditures are zero in 2010. Was the Line 406/407 Adder Project completed in 2010?

A. Yes. The Line 406 Adder Project was completed in October 2010.[91] PG&E's actual capital expenditures for the project totaled $49.7 million during the three GA IV rate years. Mr. O'Loughlin shows zero adopted capital expenditures for that project even though it was explicitly addressed in the settlement and was actually completed in 2010.

PG&E implemented a $5.1 million surcharge for the Line 406 Adder Project effective January 1, 2011. The surcharge was implemented pursuant to the GA IV Settlement.[92] Table A-2 indicates the $5.1 million surcharge was based on capital costs of $43.1 million. If that surcharge had been implemented one day earlier, Mr. O'Loughlin would have presumably shown adopted 2010 capital expenditures of $43.1 million for the Line 406 adder project in 2010. A $43.1 million increase in adopted capital expenditures should not depend on a 24-hour (or less) difference in the timing of the implementation of a rate surcharge.

Q. Would a one day change in the surcharge for the Line 406 adder project have a significant impact on ratepayers?

A. Of course not. The annual surcharge was $5.1 million. Accelerating the implementation of the surcharge by one day would have cost ratepayers $14 thousand dollars. That is a tiny amount compared to the annual charges paid by ratepayers for GT&S services. Mr.

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[91] OCHP-23.

[92] OCHP-23. The rates adopted in the GA V settlement were placed into effect on May 1, 2011. Section 8.4.1 of the GA IV Settlement provided for implementing the local transmission adder surcharges on January 1, 2011 for projects completed in 2010, if the rates established in the next rate case were not yet effective. The Line 406 Adder Project surcharge was included in rates for the first five months of 2011.

O'Loughlin's decision to reduce 2010 adopted capital expenditures by $43.1 million because PG&E did not receive $14,000 from its customers illustrates the defects in Mr. O'Loughlin's approach.

Q. Are Overland's adopted capital expenditure amounts for the local transmission adder projects reasonable?

A. Yes. The adopted total capital costs shown on Table A-2 of the GA IV settlement were taken directly from the March 2007 litigation forecast. Overland's adopted capital expenditures for 2008 and 2009 were taken directly from the same source as the adopted amounts shown on Table A-2. Overland's 2010 capital expenditures were taken from the March 2010 forecast in the 2011 GT&S rate case for the reasons explained previously.

O'Loughlin's Results Are Not Reasonable

Q. Are Mr. O'Loughlin's overall adopted capital expenditures for the GA IV rate years reasonable?

A. No. The following table compares Mr. O'Louglin's adopted and actual capital expenditures.

Table 10-10
GA IV Period
O'Loughlin Adopted and Actual Capital Expenditures
2008 to 2010
Dollars in Millions

Year	Actual	Adopted	Difference	Percentage Difference
2008	216.8	89.7	127.1	141.7
2009	200.3	158.2	42.1	26.6
2010	193.0	87.4	105.6	120.8
Total	610.1	335.3	274.8	82.0

Source: Exhibit_(MPO-1), page 43

According to Mr. O'Loughlin, PG&E spent 2.4 times its adopted capital expenditures in the first year of the GA IV period and 82 percent more than adopted over the three year GA IV period. As part of Overland's audit, I conducted a detailed review of PG&E's GT&S budget and program review documentation for the years 2008 and 2010. The documentation I reviewed did not contain any indications that PG&E knowingly spent significantly more on construction projects during those years than the amounts adopted in the GA IV settlement.

Based on my review of PG&E's internal planning documents, Mr. O'Loughlin's claim that PG&E spent 82 percent more than its adopted capital expenditures over the three-year period is not credible.

Q. Did you ask PG&E why it spent 82 percent more than its adopted capital expenditures during the GA IV period?

A. Yes. After reading Mr. O'Loughlin's testimony, I submitted discovery request OCHP-18 to determine if PG&E had an explanation. That request asked PG&E to:

> [I]dentify, describe and explain the circumstances and other factors that caused PG&E to spend 82 percent more on Capex during [the GA IV] period than the amounts adopted in the GA IV settlement. Explain why PG&E decided to spend significantly more than the adopted amounts during the period 2008 to 2010.

PG&E's response does not identify any factors that would explain the over-spending. Instead of providing real world reasons the response indicates:

> PG&E's internal budgeting and planning process was separate and independent from PG&E's decision to settle a particular rate case or the calculation of any imputed adopted amounts from a settlement...Budgets were ultimately set for each line of business according to the operational needs of the lines of business and PG&E's overall operating priorities, rather than according to the imputed adopted amounts or forecast revenues for a particular line of business..."

PG&E apparently does not know why it spent 82 percent more on capital expenditures than the amounts that Mr. O'Loughlin claims PG&E agreed upon in the GA IV Settlement.

Q. You mentioned that you did not find any indications that PG&E knowingly spent significantly higher amounts than its authorized capital expenditures during 2008 through 2010 in PG&E's budget and program review documents for those years. After you reviewed Mr. O'Loughlin's testimony, did you ask PG&E if it was aware of any such internal documents?

A. Yes. Discovery question OCHP-19 asked PG&E to "provide all contemporaneous PG&E documents that discuss the decision to spend significantly above the adopted levels and/or the factors that caused actual capital expenditures to significantly exceed the adopted amounts in those [GA IV Settlement] years." PG&E's response did not provide any documents. PG&E's response indicates:

> PG&E...is not presently aware of any documents discussing the difference between recorded gas transmission capital expenditures in 2008 - 2010 and the imputed adopted capex amounts in the Gas Accord IV settlement.

The suggestion that PG&E would spend 82 percent more than its adopted capital expenditures over a three year period and not have any internal documents that discuss the reasons for the over-spending is not credible.

PG&E's actual recorded spending levels are objectively verifiable. The absence of internal documents directly implicates the accuracy of Mr. O'Loughlin's adopted amounts.

Q. Do Mr. O'Loughlin's adopted amounts assume large ratemaking disallowances of the capital expenditures included in PG&E's March 2007 litigation forecast?

A. Yes. The following table compares Mr. O'Loughlin's adopted amounts to PG&E's March 2007 litigation forecast. [93]

Table 10-11
Gas Accord IV Period
Capital Expenditures Ratemaking Disallowances
Implied by O'Loughlin Adopted Amounts
Dollars in Thousands

Year	O'Loughlin Adopted	PG&E Litigation Forecast	Disallowance
2008	89,700	230,214	(140,514)
2009	158,200	253,655	(95,455)
2010	87,400	104,641	(17,241)
Total	335,300	588,510	(253,210)

Sources: Exhibit __(MPO-1), page 43 and PG&E March 15, 2007 Capital Expenditures Workpapers, Table 1. Includes MWC 80 because MPO adopted includes MWC 80.

Mr. O'Loughlin's adopted capital expenditure amounts assume that PG&E agreed to capital expenditures disallowances of $253 million compared to the amounts it would

[93] The Litigation forecast amounts do not agree with the 2008 and 2009 Overland adopted amounts shown on Overland Revised Table 4-1, because Overland's adopted amounts do not include MWC 80. Overland did not use the litigation forecast to set 2010 adopted capital expenditures.

have requested in a GT&S rate application. That is an average of $84 million a year. That level of disallowance would have been completely unprecedented in the prior 12 year history of the Gas Accord. There was simply no track record of the parties recommending anything close to those levels of disallowances in the prior cases.

Mr. O'Loughlin does not offer any explanation as to why PG&E would have voluntarily agreed to large unprecedented capital expenditures disallowances in a settlement agreement.[94]

The record in the GA IV Settlement proceeding does not discuss any reductions to PG&E's capital expenditures forecast. PG&E's capital expenditures forecast is in the record. The record does not identify any capital projects that were opposed by other parties.

PG&E submitted extensive testimony with its application for approval of the settlement. That testimony does not identify any challenges to PG&E's capital expenditures forecast by other parties or any reductions in PG&E's forecast that were negotiated in the settlement process.

The GA IV Settlement Agreement does not include any references to disallowances or other reductions in PG&E's capital expenditures forecast. The Settlement Agreement does adopt specific plant in service values for the five local transmission adder projects, and those amounts match the litigation forecast exactly.

Mr. O'Loughlin's assumption that PG&E voluntarily agreed to $253 million in capital expenditure disallowances in the GA IV Settlement is not credible.

[94] The August 2010 GA V Settlement adopted disallowances that averaged $39 million a year over 2011 to 2014. Mr. O'Loughlin's implied GA IV disallowances are more than double the amounts negotiated in the GA V Settlement.

Section 11
Rate Base

Q. Mr. O'Loughlin presents a comparison of actual and adopted rate base on page 26 of his Exhibit __(MPO-7). Are there any significant issues related to actual rate base?

A. No. Mr. O'Loughlin's actual rate base amounts are very close to Overland's actual rate base amounts.

Q. Have you prepared a table that compares Overland's revised adopted rate base amounts to Mr. O'Loughlin's adopted rate base amounts?

A. Yes. The following table shows that comparison.

Table 11-1
Adopted Rate Base
Overland Compared to O'Loughlin
1998 to 2010
Dollars in Thousands

Year	Overland	O'Loughlin	Difference
1998	1,461,088	1,179,194	281,894
1999	1,463,144	1,222,697	240,447
2000	1,455,993	1,247,788	208,205
2001	1,449,051	1,271,727	177,324
2002	1,442,746	1,294,506	148,240
2003	1,460,241	1,294,506	165,735
2004	1,452,044	1,452,044	0
2005	1,454,012	1,454,013	(1)
2006	1,481,493	1,481,499	(6)
2007	1,509,493	1,509,517	(24)
2008	1,549,838	1,519,060	30,778
2009	1,666,821	1,520,424	146,397
2010	1,789,983	1,521,928	268,055

Source: Overland Revised Table 5-4 and MPO Workpaper 122

Q. What caused the large differences during 1998 to 2003?

A. Mr. O'Loughlin excluded roughly half of the Line 401 rate base from his adopted rate base amounts under his Line 401 phase-in theory. That theory is wrong for the reasons explained in Section 4.

Mr. O'Loughlin included 100 percent of Line 401 in his actual rate base values and only included approximately half of the Line 401 rate base in his adopted rate base values. That distorts his comparison of actual and adopted rate base and produces the large

1998 to 2003 differences between Overland adopted rate base and his adopted rate base shown above.

In addition, Mr. O'Loughlin's adopted rate base excludes the NOx capital addition projects that were adopted in the GA I Settlement.[95] Those capital additions totaled $22.9 million.[96] The NOx capital additions were forecasted to be completed in 1998. Mr. O'Loughlin included those projects in his actual rate base amounts. Including major construction projects in actual rate base while excluding them from adopted rate base creates a mismatch that distorts the comparison of actual and adopted amounts.

Q. What caused the large differences in 2008 to 2010?

A. Overland and O'Loughlin used different methods to determine adopted rate base in those years. Overland's adopted rate base amounts were taken from PG&E's March 2007 litigation forecast for the reasons explained in Sections 9 and 10. Mr. O'Loughlin calculated 2006 to 2010 rate base by escalating the adopted rate base for 2005 by the rate of growth in the GT&S rates adopted in the GA III and GA IV Settlements. Mr. O'Loughlin's approach is invalid for the reasons explained in Sections 4 through 10.

Mr. O'Loughlin also excluded the local transmission adder projects adopted in the GA IV Settlement from his adopted rate base amounts.[97] PG&E recorded plant additions for the local transmission adder projects of $76 million in 2008 and $55 million in October 2010.[98] Mr. O'Loughlin included those plant additions in his actual rate base amounts. That creates a mismatch between Mr. O'Loughlin's actual and adopted rate base amounts.

Q. Why did Mr. O'Loughlin exclude the GA I NOx projects and the GA IV local transmission adder projects from his adopted rate base amounts?

[95] Exhibit__ (MPO-7), page 26.

[96] GA I Settlement Workpaper 14-1.

[97] Exhibit__(MPO-7), page 26.

[98] OCHP-23. The Line 108 and Line 351 projects were operational in 2008. The Line 406 project was operational in October 2010.

A. Overland asked Mr. O'Loughlin to explain why he excluded those investments from his adopted rate base in discovery question OCHP-43. The response indicates "the impact of these projects on rate base is small and no information was available from which to make a precise estimate of the contribution of the NOx or Adder projects to imputed adopted rate base."

Q. Are Overland's adopted rate base amounts reasonable?

A. Yes.

Q. Are Mr. O'Loughlin's adopted rate base amounts reasonable?

A. No. They are based on flawed theories and approaches. They also exclude several large construction projects that were adopted in the GA I and GA IV settlements. His comparison of adopted and actual rate base amounts is invalid, because the scope of his adopted amounts is smaller than the scope of his actual amounts.

Section 12

Adopted Revenue Requirements

Q. Have you prepared a comparison of actual revenues to adopted revenue requirements?

A. Yes. Overland's Revised Table 5-3 makes that comparison.

Q. Does Mr. O'Loughlin agree with the adopted revenue requirements shown on that table?

A. No. As shown on the following table, Mr. O'Loughlin's adopted revenue requirement amounts are $303 million lower than Overland's adopted amounts over the period 1999 to 2010.

Table 12-1
Comparison of Overland and O'Loughlin
Adopted Revenue Requirements
1997 to 2010
Dollars in Thousands

Year	Overland	O'Loughlin	Difference
1999	418,008	355,757	62,251
2000	422,432	365,222	57,210
2001	426,124	373,737	52,387
2002	429,992	382,203	47,789
2003	453,017	382,203	70,814
2004	438,834	438,834	0
2005	429,276	429,276	0
2006	437,393	437,390	3
2007	445,667	445,663	4
2008	449,415	448,480	935
2009	461,819	460,864	955
2010	474,266	463,752	10,514
Total	5,286,243	4,983,381	302,862

Source: Overland Revised Table 5-3 and MPO Workpaper 95

Q. What caused those differences?

A. The following table shows the differences by issue.

Table 12-2 Adopted Revenue Requirements Comparison Differences Between Overland And O'Loughlin Amounts 1999 to 2002 Dollars In Thousands						
Year	Line 401 Phase In	Customer Access Charge	2003 Approach and Rounding	Other Operating Revenues	Local Trans. Adder Projects	Total
1999	(56,307)	(5,944)	0	0	0	(62,251)
2000	(51,117)	(6,093)	0	0	0	(57,210)
2001	(46,143)	(6,245)	1	0	0	(52,387)
2002	(41,389)	(6,401)	1	0	0	(47,789)
2003	(41,389)	(6,093)	(23,332)	0	0	(70,814)
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	(3)	0	0	(3)
2007	0	0	(4)	0	0	(4)
2008	0	0	0	(935)	0	(935)
2009	0	0	0	(955)	0	(955)
2010	0	0	1	(976)	(9,539)	(10,514)
Total	(236,345)	(30,776)	(23,336)	(2,866)	(9,539)	(302,862)
Source: Overland Analysis						

Q. Do you agree with Mr. O'Loughlin on his Line 401 phase-in issue?

A. No. Mr. O'Loughlin argues that approximately half of the Line 401 revenue requirement was excluded for the revenue requirements adopted in the GA I Settlement. That position is invalid for the reasons explained in Section 4.

Q. Do you agree with Mr. O'Loughlin on his GA I Period Customer Access Charge issue?

A. No. Mr. O'Loughlin argues that the GT&S rates adopted in the GA I Settlement did not include a customer access charge. That position is invalid for the reasons explained in Section 13.

Q. Do Mr. O'Loughlin's 1999 to 2003 adopted revenue requirements agree with the representations made by PG&E in Gas Accord proceedings?

A. No. PG&E provided "Data Books" to the parties during the negotiation of the GA III and GA IV settlements. Those data books included a schedule showing the GT&S "Adopted Revenue Requirement" by year. The following table compares the adopted revenue requirements shown in PG&E's data books to Mr. O'Loughlin's adopted amounts.

Table 12-3
Comparison of Adopted Revenue Requirements
PG&E Data Books Compared to O'Loughlin
1999 to 2003
Dollars in Thousands

Year	PG&E	O'Loughlin	Difference
1999	418,008	355,757	(62,251)
2000	422,433	365,222	(57,211)
2001	426,125	373,737	(52,388)
2002	429,993	382,203	(47,790)
2003	429,993	383,203	(46,790)
Total	2,126,552	1,860,122	(266,430)

Source: OCHP-37, Attachment 2, GA III Data Book, (PDF page77) and Attachment 4, 2011 GT&S Rate Case Data Book, 1/11/10 (PDF page 104)

PG&E and the settling parties were apparently previously unaware of Mr. O'Loughlin's theories that the revenue requirements adopted in the GA I Settlement excluded roughly half of the Line 401 revenue requirement and the Customer Access Charge revenue requirement.

The adopted 1990 to 2002 revenue requirement amounts shown in PG&E's data books agree exactly with Overland's adopted amounts for those years.

Q. What caused the "2003 approach" difference shown on Table 12-2?

A. The GA II Settlement covered the rate year 2003. [99] The rates for 2003 were set equal to 2002 rates. Overland set the 2003 adopted revenue requirement equal to 2002 actual revenues to reflect the terms of the GA II Settlement. Mr. O'Loughlin set his adopted 2003 revenue requirement equal to his adopted revenue requirement for 2002.

Q. Why did Overland set the 2003 adopted revenue requirement equal to actual 2002 revenues?

A. PG&E did not submit any cost-of-service information in the GA II Settlement proceedings. The Settlement extended PG&E previously authorized rates for 2002 through the end of the 2003 rate year. Therefore, the best available estimate of the amount of revenue that PG&E was "authorized" to collect in 2003 was the amount it actually collected in 2002.

[99] Mr. O'Loughlin refers to the GA II Settlement as the GA I Extension. Overland refers to the GA II Settlement as the GA II Settlement, because the title of the settlement agreement is the "Gas Accord II Settlement Agreement" and the CPUC Decision that approved the settlement is titled "Opinion Regarding the Joint Motion For Approval of the Gas Accord II Settlement Agreement."

Q. Is Overland's estimate of 2003 adopted revenue requirements reasonable?

A. Yes. Overland's 2003 adopted revenue requirements are consistent with the substance of the GA II Settlement Agreement.

Q. Does the Commission's decision in PG&E's 2004 Test Year GT&S rate case identify an adopted revenue requirement for 2003?

A. Yes. Page 3 of that decision states "The [2004] adopted revenue requirement represents an increase of 2.94% over 2003 gas transmission and storage rates of $423.9 million."[100] Mr. O'Loughlin's 2003 adopted revenue requirement is $40.7 million below that amount.

Overland's 2003 adopted revenue requirement is $24.7 million higher than the amount stated on page 3 of the 2004 Test Year rate case decision. PG&E's Gas Accord data books and the 2004 Test Year rate case decision imply that PG&E and the Commission viewed the 2003 adopted revenue requirement as being equal to the 2002 adopted revenue requirement, including 100 percent of Line 401 and the customer access charges. In my opinion, setting the 2003 adopted revenue requirement equal to actual 2002 revenues more accurately reflects the substance of the GA II Settlement.

Q. What caused the 2008 to 2010 Other Operating Revenue differences shown on Table 12-2?

A. Overland calculated the 2008 to 2010 adopted revenue requirements by adding Other Operating Revenues to the revenue requirements shown on Appendix A, Table A-4 of the GA IV Settlement Agreement. The following table shows Overland's calculations.

Table 12-4
Overland Adopted Revenue Requirements
GA IV Period
2008 to 2010
Dollars in Thousands

Description	2008	2009	2010
Revenue Requirement From GA IV Table A-4	446,493	458,875	471,299
Other Operating Revenues	2,922	2,944	2,967
Total Adopted Revenue Requirement	449,415	461,819	474,266

Source: Overland Workpaper 5-12

Mr. O'Loughlin used the same approach. However, he used a different source for his Other Operating Revenues amounts. Overland took the adopted Other Operating

[100] D.03-12-061, page 3.

Revenue Amounts from PG&E's March 2007 Litigation Forecast. Mr. O'Loughlin escalated his 2005 adopted Other Operating Revenues to 2008, 2009 and 2010 using the growth rates in total customer rates adopted in the GA III and GA IV settlements. The Other Operating Revenue difference is a product of the different approaches taken by Overland and O'Loughlin.

Q. Are Overland's adopted Other Operating Revenue amounts for 2008, 2009 and 2010 reasonable?

A. Yes. PG&E's March 2007 Litigation forecast provides a reasonable basis for determining adopted Other Operating Revenues for the reasons stated in Sections 9 and 10. Mr.O'Loughlin's approach should be rejected for the reasons stated in those Sections.

Q. What caused the 2010 Local Transmission Adder Project difference on Table 12-2?

A. Overland used the 2010 adopted revenue requirement stated on Table A-4 of Appendix A of the GA IV Settlement Agreement. That revenue requirement includes $23.96 million for local transmission adder projects. Mr. O'Loughlin reduced the local transmission adder project revenue requirement by $9.5 million because the completion of the Line 406/407 projects was delayed and the rate surcharge for those projects was not implemented until January 1, 2011.[101]

Q. Is Overland's 2010 adopted revenue requirement for local transmission adder projects reasonable?

A. Yes. Overland's adopted revenue requirement for those projects was taken directly from the Settlement Agreement. The local transmission adder projects are discussed in more detail in Section 10.

O'Loughlin's Adopted Revenue Requirement Comparison

Q. On page 56 of his testimony, Mr. O'Loughlin indicates that "Overland's recommendations lead to revenue requirement levels that are $382 million greater than the Commission approved figures." How did he calculate that amount?

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[101] The rate surcharge amounts for the Line 406/407 local transmission adder projects are shown on Table A-2 of Appendix A of the GA IV Settlement Agreement.

A. Mr. O'Loughlin calculated that amount on his Figure 16.[102] That figure compares his adopted revenue requirements to his adjusted version of Overland's adopted revenue requirements.[103]

Figure 16 repeats the comparison made in Tables 12-1 and 12-2 for seven of the twelve years included in the study period.[104] Mr. O'Loughlin adjusted Overland's adopted revenue requirements in the other five years. The differences in those five years are explained below.

Mr. O'Loughlin's comparison is shown on the following table.

Table 12-5
O'Loughlin's Adopted Revenue Requirement Comparison
1999 to 2010
Dollars in Millions

Year	Commission Approved Per MPO	Consistent With Overland Recommendations Per MPO	Difference
1999	355.8	418.0	(62.2)
2000	365.2	422.4	(57.2)
2001	373.7	426.1	(52.4)
2002	382.2	430.0	(47.8)
2003	382.2	448.6	(66.4)
2004	438.8	438.8	0.0
2005	429.3	429.3	0.0
2006	437.4	437.4	0.0
2007	445.7	448.7	(3.0)
2008	448.5	460.1	(11.6)
2009	460.9	486.9	(26.0)
2010	463.8	518.9	(55.1)
Total	4,983.5	5,365.2	(381.7)

Source: Exhibit __(MPO-1), page 57, Figure 16

All of the amounts included in the "Commission Approved Per MPO" column agree with Mr. O'Loughlin's adopted revenue requirement amounts. The amounts appearing in the column titled "Consistent with Overland Recommendations per MPO" agree with Overland's adopted amounts in 1997 to 2002 and in 2004 to 2006

[102] Exhibit_(MPO-1), page 57, Figure 16.

[103] Mr. O'Loughlin refers to his adopted revenue requirements as "Commission Approved Revenue Requirements" on Figure 16. He refers to his adjusted version of Overland's adopted revenue requirements as "Revenue Requirements Consistent with Overland's Recommendations."

[104] Those years are 1999 to 2002 and 2004 to 2006.

Q. What caused the differences shown on Mr. O"Loughlin's Figure 16 in 1999 to 2002?

A. All of the differences in those years were caused by Mr. O'Loughlin's invalid GA I "Line 401 Phase-in" and Customer Access Charge theories. Sections 4 and 13 explain why those theories are wrong. The differences shown on Mr. O'Loughlin's Figure 16 for those years agree with the differences shown on Tables 12-1 and 12-2.

Q. What causes the Figure 16 difference in 2003?

A. The 2003 differences consist of the differences shown on Table 12-2 plus an additional timing differences. The following table shows the 2003 differences by component.

Table 12-6
O'Loughlin's Adopted Revenue Requirement Comparison
2003 Differences By Component
Dollars in Millions

Description	Amount
Line 401 Phase-in Difference (Table 12-2)	(41.4)
Customer Access Charge Difference (Table 12-2)	(6.1)
2003 Method Difference (Table 12-2)	(23.3)
Reverse Change Overland Made to Adopted RRQ (Section 3)	4.4
Total Difference per MPO Figure 16	(66.4)

Source: Table 12-2, Overland Revised Table 5-3 and Exhibit_(MPO-1), page 57, Figure 16

The last reconciling item results from the fact that Mr. O'Loughlin worked from Overland's original report when he prepared his Figure 16. Overland revised its 2003 adopted revenue requirements in Section 3, and Tables 12-1 and 12-2 reflect that revision.[105] The $4.4 million difference shown above simply reflects the fact that Overland changed one of the starting points for Mr. O'Loughlin's comparison after he submitted his testimony.

Q. What caused the 2007 difference shown on Mr. O'Loughlin's Figure 16?

A. Mr. O'Loughlin increased Overland's 2007 adopted revenue requirement by $3.1 million to reflect the difference between his adopted capital expenditures and the Overland's adopted capital expenditures for that year.[106]

[105] Overland's adopted 2003 revenue requirements are based on actual 2002 revenues. Overland revised its actual 2002 revenues to include a storage carrying charge adjustment recommended by Mr. O'Loughlin. That changed Overland's 2003 adopted revenue requirement.

[106] Mr. O'Loughlin's adjustment is calculated on Exhibit_(MPO-5), page 6.

Q. Does the 2007 difference shown on Figure 16 somehow demonstrate that Overland's 2007 adopted capital expenditures are wrong and Mr. O'Loughlin's are right?

A. No. The difference simply reflects that fact that Overland's adopted 2007 capital expenditures are higher than Mr. O'Loughlin's adopted 2007 capital expenditures.

Q. What caused the Figure 16 differences in 2008 and 2009?

A. Mr. O'Loughlin adjusted Overland's adopted revenue requirements to reflect the revenue requirements produced by PG&E's March 2007 litigation forecast. The 2008 and 2009 differences are shown below by component.

Table 12-7
O'Loughlin Adopted Revenue Requirement Comparison
2008 and 2009 Differences
Dollars in Millions

Description	2008	2009
Overland Adopted Revenue Requirement	449.4	461.8
Litigation Forecast Adopted Revenue Requirement	460.1	486.9
Difference	(10.7)	(25.1)
Other Operating Revenue Difference (Table 12-2)	(0.9)	(0.9)
Total Difference Per MPO Figure 16	(11.6)	(26.0)

Source: Overland Workpaper 5-12 and Exhibit __(MPO-1), page 57, Figure 16

Q. Why did Mr. O'Loughlin increase Overland's 2008 and 2009 adopted revenue requirements to reflect PG&E's March 2007 litigation forecast?

A. Overland's 2008 through 2010 adopted revenue requirements were taken from Appendix A, Table A-4, of the GA IV Settlement Agreement. Mr. O'Loughlin increased Overland's adopted 2008 and 2009 revenue requirements because Overland's adopted O&M and capital expenditures for those years were taken from the litigation forecast.[107]

Q. What caused the Figure 16 difference in 2010?

A. Mr. O'Loughlin adjusted Overland's adopted revenue requirements to reflect PG&E's March 2007 litigation forecast and then added another $5.8 million to account for the difference between the capital expenditures used by Overland and the capital expenditures included in PG&E's litigation forecast.

Q. Do you agree with Mr. O'Loughlin's proposed adjustments to Overland's 2008, 2009 and 2010 adopted revenue requirements?

[107] Exhibit_(MPO-1), page 59.

A. No. Overland's adopted revenue requirement amounts are included in its comparison of actual and adopted revenues. The purpose of that comparison is to compare actual revenues to the revenue requirements approved by the Commission. The Commission approved the GA IV Settlement in D.07-09-045. Therefore, the revenue requirements specified in the GA IV Settlement are the proper values to be included in the revenue comparison shown on Overland Revised Table 5-3.

Q. Does the fact that PG&E's March 2007 litigation forecast produced higher revenue requirements than the values shown in the GA IV Settlement demonstrate that Overland's 2008, 2009 and 2010 adopted O&M and capital expenditures are wrong?

A. No. Overland used PG&E's litigation forecast to determine the GA IV period adopted O&M and capital expenditures values for the reasons explained in Sections 9 and 10.[108]

Mr. O'Loughlin's analysis does not demonstrate anything about 2008, 2009 and 2010 adopted values beyond the fact that the revenue requirements produced by PG&E's March 2007 litigation forecast are higher than the revenue requirements specified in the GA IV Settlement Agreement for those years. That fact does not come as a surprise. Table 2-4 of the Overland Report compared the litigation forecast revenue requirements to the amounts specified in the GA IV Settlement Agreement. Overland considered that information when it developed its recommendations.

[108] With the exception of 2010 adopted capital expenditures. The basis for Overland's adopted 2010 capital expenditures is also explained in Section 10.

Section 13
Actual Revenues

Q. Why are actual GT&S revenues important?

A. Actual GT&S revenues are used in the determination of the actual return on equity earned by PG&E's GT&S operations. Actual revenues are also part of the comparison of actual revenues to adopted revenue requirements.

Q. Are there any remaining issues related to actual GT&S revenues?

A. Only one. The following table reconciles Overland's actual revenues to Mr. O'Loughlin's actual revenues.

Table 13-1
Comparison of Actual Revenues
Overland Compared to O'Loughlin
1997 to 2010
Dollars in Thousands

Year	Overland	Customer Access Charge	Unlocated	O'Loughlin
1999	379,090	(5,247)	0	373,843
2000	434,786	(6,045)	0	428,741
2001	518,159	(6,671)	(100)	511,388
2002	453,017	(6,093)	100	447,024
2003	378,690	(5,670)	0	373,020
2004	428,893	0	100	428,993
2005	448,007	0	0	448,007
2006	476,716	0	(210)	476,506
2007	490,691	0	0	490,691
2008	498,851	0	0	498,851
2009	515,034	0	(100)	514,934
2010	508,324	0	200	508,524
Total	5,530,258	(29,726)	(10)	5,500,522

Source: Overland Revised Table 5-3 and Exhibit (MPO-7), page 7

Mr. O'Loughlin excluded Customer Access Charge (CAC) revenue from actual revenues during 1999 to 2003. Overland included CAC revenue in all years.

Q. Why did Mr. O'Loughlin exclude Customer Access Charge revenues from actual revenues during 1999 to 2003?

A. On page 9 of Exhibit___(MPO-7), Mr. O'Loughlin states:

Overland includes Customer Access Charge (revenues) throughout the 1999 - 2010 period, whereas I included them only from 2004 onwards. In Gas Accord I there is no evidence that there were any associated Customer Access Charge costs to the GT&S business, nor that such costs formed part of the GT&S revenue requirement - in fact these costs were incurred by the distribution business and recovered in distribution rates.

Q. Did the GA I Settlement adopt customer access charges?

A. Yes. The GA I Settlement clearly adopted separate customer access charges for transmission level customers. Page 34 of the GA I Settlement states that the new transmission rates established in the settlement include “a customer access charge to cover the costs of meters and service drops, meter reading, billing and payment processing where applicable.”

Page 35 of the GA I Settlement states “[f]our rate components will be applicable to on-system transmission service, a backbone transmission charge, a local transmission charge, a customer class charge, and a customer access charge....The transmission level customer access charge will not change from the rate set forth in this Accord...”

Page 42 of the GA I Settlement states “[e]nd users who are directly connected to the transmission system will pay a customer access charge each month. The purpose of the customer access charge is to assess the end-user a fee for the cost of providing and maintaining an individual end-user’s service connection to the transmission system...”

Page 42 of the GA I Settlement indicates the “[c]ustomer access charges escalate at 2.5 percent per year annually” and “[c]ustomer access charges for transmission level customers are guaranteed for the Accord Period, subject only to z-factor changes...”

Page 84 of the Settlement shows the customer access charge rates adopted in the GA I Settlement. The rates apply to on-system customers directly connected to the Transmission System.

GA I Settlement workpapers 21-1 to 21-7 show the development of the Customer Access Charge rates. The rates for 1999 are based on a customer access charge revenue requirement of $5.944 million, as shown on workpaper 21-4. The customer access charge revenue requirements for 2000, 2001 and 2002 escalate at 2.5 percent a year as shown on workpapers 21-5 through 21-7.

Q. Did the CAC revenue requirements adopted in the GA I Settlement include customer access costs for customers that were connected to PG&E's distribution system?

A. No. As shown on GA I Settlement workpapers 21-2 to 21-7, the customer access charges were calculated by dividing the CAC revenue requirement by the "throughput of directly connected customers only." The throughput of the directly connected customers was calculated by subtracting the "LDC distribution T-Put" from the "Total T-Put of System."[109] The CAC rates adopted in the GA I Settlement clearly did not apply to customers who were connected to PG&E's distribution system.

Q. Were the Customer Access Charge costs for transmission level customers removed from PG&E's distribution rates in the GA I Settlement?

A. Yes. Section III.C of the GA I Settlement describes distribution rates and cost allocation. Part 1 of that section, titled Distribution Revenue Requirement Assumptions, states:

> The initial natural gas distribution revenue requirement will match PG&E's 1996 GRC Decision 95-12-055, consistent with the transfer of DFMs (Distribution Feeder Mains) to local transmission. Customer Access charges for transmission-level end-users have been moved from the distribution revenue requirement to the customer access charge.

GA I Settlement workpaper 21-1 provides an overview of the calculation of the customer access charges. That workpaper states:

> The customer access charge was calculated by removing the customer scaled marginal cost revenue associated with industrial transmission, UEG (Utility-owned generation), wholesale and cogeneration transmission customers from the LDC's revenue requirement (see...the Distribution rate workpapers). These revenues were then used to develop customer access charges for each noncore transmission customer class.

The GA I Settlement workpapers for distribution rates are numbered 22-1 to 22-7. Page 22-1 provides an overview of the calculation of the revised distribution rates adopted in the GA I Settlement. That process included the following step "[r]emove embedded cost

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[109] LDC stands for Local Distribution Utility.

revenue requirement and marginal revenues associated with...customer access charges..."

The GA I Settlement clearly included customer access charge rates for end-users directly connected to transmission facilities. The costs recovered in those CAC rates were removed from the distribution revenue requirement.

Q. Has PG&E admitted that the costs recovered through the CAC were removed from distribution rates in the GA I Settlement?

A. Yes. GA I Settlement workpaper 22-2 shows the removal of $315.8 million in Gas Accord costs from distribution rates. Overland submitted discovery request OCHP-51 after reviewing Mr. O'Loughlin's testimony. That question asked for the details of those costs. PG&E's response shows that the 1996 CAC revenue requirement of $5.7 million was removed from PG&E's distribution rates.

Q. Overland included Customer Access Charge revenue in its actual revenues. How do the actual revenue amounts compare to the adopted revenue requirement for customer access charges?

A. The following table compares actual customer access charge revenues to the revenue requirements shown in the CAC rate design workpapers for 1999 to 2002.

Table 13-2
Comparison of Actual and Adopted
Customer Access Charge Revenues per Overland
1999 to 2002
Dollars in Thousands

Year	Actual Revenue	Adopted	Difference
1999	5,247	5,944	(697)
2000	6,045	6,093	(48)
2001	6,671	6,245	426
2002	6,093	6,401	(308)
Total	24,056	24,683	(627)

Sources: Overland Workpaper 5-3 and GA I Settlement WPs 21-4 to 21-7

Overland's actual CAC revenues are very close to the CAC revenue requirements adopted in the GA I Settlement. Overland's adopted and actual CAC revenue amounts clearly have the same scope.

Q. Mr. O'Loughlin claims that customer access costs were recovered through distribution rates during the GA I period. Do transmission level customers pay distribution rates?

A. No. The CAC access charges adopted in the GA I Settlement applied only to on-system end-users that received service directly from PG&E's transmission system. Under the Gas Accord structure, those customers do not pay distribution rates and the customer access costs incurred to serve those customers cannot be recovered through distribution rates.

Q. What evidence does Mr. O'Loughlin cite to support his claim that Customer Access Charge costs were excluded from GT&S rates during the GA I period?

A. Mr. O'Loughlin relies on Gas Accord I Workpaper 12-1 and page C-12 of Appendix C of the 1996 GRC Decision.[110] He notes that all of the Gas Department Customer Accounts expenses adopted in the 1996 GRC are shown under the distribution column on GA I Workpaper 12-1. Based on that observation he concludes:

> In Gas Accord I, the evidence establishes that Customer Account and Customer Services expenses were recovered in the GRC proceeding through PG&E's gas distribution rates.

Q. Does GA I Settlement Workpaper 12-1 demonstrate that the CAC revenue requirement continued to be included in distribution rates during the GA I period?

A. No. GA I Settlement Workpaper 12-1 only shows part of the GA I Settlement revenue requirement. Workpaper 12-1 excludes the revenue requirements adopted for Line 401, the NOx plant additions and customer access charges.

The Line 401 revenue requirements are developed on workpaper 15-1. The NOx plant addition revenue requirements are developed on workpaper 14-1. The revenue requirements for customer access charges were developed separately and are shown on workpapers 21-1 to 21-7. Observing that the GT&S revenue requirements developed on workpaper 12-1 do not include Line 401 or the NOx plant additions does not demonstrate that those revenue requirements were excluded from the rates adopted in the GA I Settlement. Similarly, the observation that Customer Accounts costs were excluded from the GT&S revenue requirements developed on workpaper 12-1 does not demonstrate that CAC revenue requirements were excluded from GT&S rates. The CAC

[110] Exhibit__(MPO-1), page 37, footnote 72

revenue requirements are recovered through the separate CAC rates adopted in the GA I Settlement.

Q. The actual Customer Accounts expenses that Overland included in its analysis of actual return on equity are significantly lower than the CAC revenue requirements adopted in the GA I Settlement. Do CAC revenue requirements consist entirely of Customer Accounts expenses?

A. No. The purpose of the customer access charge is to recover the "costs of meters and service drops, meter reading, billing and payment processing where applicable." The costs of the meters and service drops are largely associated with rate base investments and depreciation expense, not O&M expenses. Customer accounts expenses are only a portion of the CAC revenue requirement for end-users that are connected directly to the transmission system.

Mr. O'Loughlin's treatment of actual Customer Accounts expenses during the GA I period is addressed in Section 15.

Q. Should Customer Access Charge revenues be included in actual GT&S revenues during the GA I Period?

A. Yes. The GA I Settlement adopted CAC rates for end-users that were directly connected to PG&E's transmission system. The revenue requirements recovered in the CAC rates were removed from PG&E's distribution rates as part of the GA I Settlement. Actual GT&S revenues should include all of the revenues produced by the GT&S rates adopted in the GA I Settlement.

Section 14

Actual Functional O&M Expenses

Q. Have you prepared a table that compares Overland's actual functional O&M expenses to Mr. O'Loughlin's values?

A. Yes. Functional O&M consists of production, transmission and storage O&M. The following table compares Overland's actual (recorded) functional O&M amounts to Mr. O'Loughlin's amounts.[111]

Table 14-1
Actual Functional O&M Expenses
Comparison of Overland and O'Loughlin Amounts - 1997 to 2010
Excludes Customer Accounts and Sales Expenses
Dollars In Thousands

Year	Actual O&M Per Overland	Account 819 Storage - Fuel	Account 855 Trans - Fuel	San Bruno Incident	Form 2 And Rounding	Actual O&M Per MPO
1997	56,936	(129)	0	0	(26)	56,781
1998	64,160	(723)	0	0	1	63,438
1999	56,348	(808)	0	0	1	55,541
2000	59,378	(1,404)	0	0	0	57,974
2001	66,815	(3,713)	0	0	1	63,103
2002	64,189	(2,370)	0	0	(1)	61,818
2003	65,245	(1,561)	0	0	0	63,684
2004	70,749	(1,398)	0	0	0	69,351
2005	74,819	0	0	0	0	74,819
2006	75,615	0	0	0	(198)	75,417
2007	77,854	0	0	0	0	77,854
2008	81,991	0	286	0	1	82,278
2009	86,902	0	303	0	0	87,205
2010	80,103	0	1,388	21,775	0	103,266
Total	981,104	(12,106)	1,977	21,775	(221)	992,529

Sources: Revised Overland Table 3-1, Overland Workpaper 3-7 and MPO Workpapers, page 39

Account 819 - Storage Compressor Fuel

Q. Why did Mr. O'Loughlin exclude a portion of Account 819 from his actual O&M expenses in 1997 to 2004?

A. Account 819 is Storage Compressor Station Fuel and Power. Account 819 includes two types of costs, electricity for electric compressor units and gas for gas-fueled units. Mr. O'Loughlin excluded the gas cost portion of Account 819 from his actual O&M expenses in 1997 to 2004. He excluded account 819 gas costs from actual O&M "because

[111] The Form 2 and Rounding column includes two types of differences. First, the amounts for some FERC O&M accounts reported in PG&E's 1997 and 2006 FERC Form 2 reports did not agree with the amounts PG&E reported in the response to OC-296 for those accounts. The starting points for Overland's actual O&M expenses in those years agree with the FERC Form 2, Mr. O'Loughlin's do not. The differences shown for the other years are rounding differences.

Account 819 gas fuel costs were recovered through a separate in-kind shrinkage allowance rate for the entire period of 1997-2004."[112]

Q. Should Account 819 gas costs be excluded from actual O&M during 1997 to 2004?

A. No. Account 819 gas costs were included in the O&M expenses adopted in the GA I Settlement and the 2004 Test Year GT&S rate case. Account 819 gas costs are fully included in both Overland's and Mr. O'Loughlin's adopted O&M expenses for 1997 to 2004. Excluding Account 819 gas costs from actual O&M would create a mismatch in the scope of the adopted and actual O&M expenses for those years.

Q. How did you determine that gas costs were included in the Account 819 O&M expenses adopted in the GA I Settlement?

A. The 1996 O&M expenses adopted in the GA I Settlement were taken from the 1996 GRC Decision. Page C-8 of Appendix A of that decision shows the adopted amount for Account 819 of $2.857 million, in 1993 dollars.[113] The adopted amount agreed with PG&E's forecast in the 1996 GRC. PG&E's forecast equaled the total 1993 costs recorded in Account 819, less $67,000 for costs recovered in other proceedings. PG&E admits that the adopted amount included both electricity and gas costs.[114] According to PG&E, including the Account 819 gas costs in the O&M expenses adopted in the GA I Settlement "was done in error."[115]

Q. How did you determine that gas costs were included in the Account 819 O&M expenses adopted in the 2004 Test Year GT&S rate case?

A. PG&E provided an adopted Results of Operations model for the 2004 Test Year GT&S rate case. The Adopted R.O. model supports and agrees with the adopted revenue requirements components shown in Attachment A to the decision in the 2004 Test Year rate case.[116] The adopted R.O. files show adopted O&M expense by FERC account. The

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[112] Exhibit__(MPO-1), page 39.

[113] The total storage expenses shown on Appendix A, Page C-8, agree with the Storage expenses shown on GA I Settlement workpaper 12-1, after the local storage costs shown under the distribution column are removed from the total on workpaper 12-1.

[114] OCHP-31.

[115] OCHP-32.

[116] D.03-12-061.

adopted amount for Account 819 is $3.931 million. That amount is exactly the same as the amount requested by PG&E for Account 819 in its O&M workpapers. The requested 2004 amount equaled the 2001 recorded total cost charged to Account 819, escalated to 2004 dollars. According to PG&E's response to data request OC-198, the 2001 recorded Account 819 costs consisted entirely of gas fuel costs. The O&M expenses adopted in the 2004 Test Year GT&S rate case clearly included $3.931 million of Account 819 gas costs.

Q. Why did you exclude Account 819 gas costs from actual O&M in 2005 through 2010?

A. Overland was not able to determine if Account 819 gas costs were included in the 2005 O&M expenses adopted in the GA III Settlement. Overland accepted PG&E's representation that the 2005 O&M expenses adopted in that GA III settlement excluded Account 819 gas costs.[117]

PG&E excluded Account 819 gas costs from its March 2007 litigation forecast of O&M expenses in the GA IV proceeding.[118] Overland's adopted O&M expenses for 2008 to 2010 were taken from PG&E's litigation forecast. Overland excluded Account 819 gas costs from its actual O&M expenses in 2005 to 2010 to match the scope of its adopted Account 819 costs for those years.

Account 855 - Transmission Other Compressor Fuel

Q. Your table shows a difference in 2008 through 2010 for Account 855. What caused that difference?

A. Account 855 is Transmission, Other Fuel and Power For Compressor Stations. The Account 855 differences are caused by the different approaches taken by Overland and O'Loughlin to determine adopted O&M amounts during the GA IV Settlement period.

PG&E excluded Account 855 from its March 2007 litigation forecast entirely. PG&E's second supplemental response to OC-296 indicates Account 855 "was mistakenly excluded from" the litigation O&M forecasts for 2008, 2009 and 2010. Overland's adopted O&M expenses for 2008 to 2010 were taken from the litigation forecast.

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[117] Second Supplemental Response to OC-296.

[118] OC-127.

Overland excluded Account 855 from actual O&M in 2008 to 2010 to match the scope of its adopted O&M for those years.

Mr. O'Loughlin did not use the litigation forecast to establish his adopted O&M for 2008 to 2010. Instead, he escalated 2005 adopted O&M through 2010 using the overall annual escalation in customer rates adopted in the GA III and GA IV settlements. Account 855 was included in the 2005 O&M expenses adopted in the GA III settlement. Mr. O'Loughlin included Account 855 in his actual O&M expenses for 2008 to 2010 to match the scope of his adopted O&M expenses.

<u>San Bruno Incident O&M Costs</u>

Q. What are San Bruno Incident O&M costs?

A. San Bruno Incident (SBI) costs are the costs that PG&E incurred after the September 2010 San Bruno pipeline explosion to maintain service and verify the safety of its system. The SBI costs include the costs of short-term safety-related measures implemented in 2010 in response to the SBI, including an accelerated leak survey of PG&E's entire transmission system transmission and an effort to validate the maximum allowable operating pressure of all transmission pipelines located in high consequence areas.[119]

Q. Why did Overland exclude SBI costs from actual (recorded) O&M in 2010?

A. The CPSD determined that the San Bruno explosion was a direct consequence of multiple violations of the CPUC's gas safety rules. The SBI costs are the direct consequence of safety rules violations and are not recoverable in GT&S rates. For that reason, the SBI costs should be excluded from the actual O&M expenses used in the comparison of actual and adopted O&M.

Q. Is your treatment of SBI costs consistent with your treatment of other costs that are not recoverable in rates?

A. Yes. PG&E incurred approximately $191 million of non-recoverable environmental remediation costs for chromium emissions at the Topock and Hinkley compressor

[119] OC-210 and Overland Report, page 3-2.

stations during the period 1997 to 2010.[120] Overland excluded the chromium remediation costs from its actual O&M costs because they are not recoverable in rates. PG&E excluded the chromium remediation costs from its GT&S rate applications and the costs were excluded from the O&M amounts adopted in the applicable Gas Accord Settlements.

Q. Did Mr. O'Loughlin exclude the non-recoverable chromium remediation costs from his actual O&M expenses?

A. Yes. The SBI costs are also non-recoverable and should receive the same treatment as the non-recoverable chromium remediation costs.

Q. On pages 19 and 20 of his testimony, Mr. O'Loughlin indicates he included SBI costs in actual 2010 O&M expenses because the costs were incurred and because "GT&S may have spent additional funds on other operations had it not been responding to the San Bruno accident." What is your response to those arguments?

A. Non-recoverable costs should be excluded from actual O&M expenses. The SBI costs are the direct result of multiple violations of safety rules and are non-recoverable.

It is likely that some unknown portion of the money spent on the SBI response was diverted from normal GT&S activities. Overland's actual 2010 O&M expenses are $80.1 million. Adding the SBI costs to that amount produces $101.9 million. That amount is only $15.0 million higher than Overland's actual 2009 O&M costs. The SBI costs totaled $21.8 million. Based on that comparison, it is plausible to argue that some of the money spent on the SBI response was diverted from normal GT&S activities.

Any spending that was diverted from PG&E's normal operations was not spent on normal GT&S activities. PG&E should not be given credit for spending money on normal GT&S activities in the O&M comparison, when in fact, the money was not spent on normal GT&S activities.

Estimating what PG&E would have spent for its normal GT&S activities in 2010 if the SBI had not occurred is not necessary and a matter of speculation. In light of PG&E's

[120] Overland response to PG&E Discovery Question 24, Attachment 24-1. The $191 million is calculated from PG&E's response OC-296.

multiple violations of safety rules, any ambiguity concerning the dollar amounts diverted away from normal operations should be interpreted in favor of the ratepayer, if it is subsequently determined that an estimate is needed.

Section 15

Customer Accounts and Sales Expenses

Q. Did Mr. O'Loughlin include Customer Accounts and Sales expenses in his comparison of adopted and actual O&M?

A. Yes. Mr. O'Loughlin included Accounts 903 and 912 in his comparison. Account 903 is Customer Records and Collection Expenses. Account 912 is Demonstration and Selling Expenses. I use the shorthand titles Customer Accounts expense for Account 903 and Sales expense for Account 912.[121]

Q. How does including Customer Accounts and Sales expenses impact the results of Mr. O'Loughlin's O&M comparison?

A. The following table shows the adopted and actual Customer Accounts and Sales expenses included in Mr. O'Loughlin's O&M comparison.

Table 15-1
Comparison of Adopted and Actual
Customer Accounts and Sales Expense Per O'Loughlin
1997 to 2010
Dollars in Thousands

Year	Actual	Adopted	Difference
1997	8,402	0	8,402
1998	7,300	0	7,300
1999	6,388	0	6,388
2000	7,166	0	7,166
2001	6,716	0	6,716
2002	7,083	0	7,083
2003	5,605	0	5,605
2004	7,775	9,833	(2,058)
2005	7,576	9,700	(2,124)
2006	7,614	9,884	(2,270)
2007	9,090	10,070	(980)
2008	9,680	10,134	(454)
2009	7,893	10,143	(2,250)
2010	7,300	10,153	(2,853)
Total	105,588	69,917	35,671

Source: MPO Workpapers pages 2 and 38

According to Mr. O'Loughlin, actual Customer Accounts and Sales expenses exceeded the adopted amounts by $36 million over the entire study period. His differences show a distinct pattern, with $48.6 million of overspending in 1997 through 2003 and $13.0 million of underspending during 2004 through 2010.

[121] The full titles are from the FERC Uniform System of Accounts. Recorded costs also include a very small amount for Account 910, Miscellaneous Customer Service and Information Expenses as shown on OC-296.

Q. Did Overland include Customer Accounts and Sales expenses in its comparison of actual and adopted O&M?

A. No. Overland excluded those costs from its O&M comparison for the reason stated in Section 1. Overland has not developed estimates of adopted Customer Accounts and Sales Expenses.

Overland included actual Customer Accounts and Sales Expenses in its actual return on equity calculations. The following table compares the actual expenses used by Overland and O'Loughlin.

Table 15-2
Comparison of Overland And O'Loughlin
Actual Customer Accounts and Sales Expenses
1999 to 2010
Dollars in Thousands

Year	Overland	O'Loughlin	Difference
1999	948	6,388	(5,440)
2000	1,043	7,166	(6,123)
2001	900	6,716	(5,816)
2002	2,076	7,083	(5,007)
2003	7,600	5,605	1,995
2004	7,775	7,775	0
2005	7,576	7,576	0
2006	7,614	7,614	0
2007	9,090	9,090	0
2008	9,680	9,680	0
2009	7,893	7,893	0
2010	7,300	7,300	0
Total	69,495	89,886	(20,391)

Source: Overland Revised ROE Analysis and MPO Workpaper Page 38

Q. What caused the differences?

A. The differences consist of two components. Mr. O'Loughlin excluded Customer Account expenses from his actual costs during 1997 to 2003. Overland included Account 903 in its actual costs in all years.

Mr. O'Loughlin included Sales expenses in his actual O&M in all years. Overland excluded Sales expenses during 1999 to 2002. Overland included Account 912 in all other years.

The following table shows the resulting differences by account.

Table 15-3 Actual Customer Accounts and Sales Expenses Difference By Account 1999 to 2003 Dollars in Thousands			
Description	Account 903	Account 912	Total
Per Overland	6,962	5,605	12,567
Per O'Loughlin	0	32,958	32,958
Difference	6,962	(27,353)	(20,391)
Source: Overland Revised ROE Analysis and MPO Workpaper Page 38			

Q. Why did Mr. O'Loughlin exclude Account 903 from his actual costs during 1999 to 2003?

A. Customer Accounts expenses are recovered through the Customer Access Charge. As discussed in Section 13, Mr. O'Loughlin's theory is that CAC costs were excluded from the revenue requirements and O&M costs adopted in the GA I Settlement. He excluded Customer Accounts expenses from his actual expenses for 1999 to 2003 to match the scope of his adopted amounts.[122]

Q. Should Customer Accounts expenses be excluded from actual O&M during the GA I Period?

A. No. As explained in Section 13, Mr. O'Loughlin's theory about the treatment of CAC costs in the GA I Settlement is incorrect. Customer Accounts expenses were included in the CAC revenue requirement adopted in the GA I Settlement and were recovered through GT&S rates. Accordingly, Customer Accounts expenses should be included in GA I Period actual costs.

Q. Why did Overland exclude Sales expenses from actual O&M during 1999 to 2002?

A. The rates adopted in the GA I Settlement were based on the gas department revenue requirements approved in PG&E's 1996 General Rate Case (GRC). The Commission denied PG&E's request to include Sales expenses in rates in the 1996 GRC.

The rates adopted in the 1996 GRC were approved in D.95-12-055. Table 8 of Appendix C to that decision is titled Gas Department Marketing Expenses Summary. That table shows PG&E's requested amount of $5.6 million for Account 912 and an adopted amount of zero for that account. Account 912 is shown under the heading "Market Building/Market Retention Exp."

[122] Exhibit___(MPO-3), pages 13 to 15.

Q. What costs were charged to Account 912 under the FERC Uniform System of Accounts at that time?

A. The FERC Uniform System of Accounts included the following definition of Account 912.[123]

> This account shall include the cost of labor, materials used and expenses incurred in promotional, demonstrating, and selling activities, except by merchandising, the object of which is to promote or retain the use of utility services by present and prospective customers.

Q. Why did the Commission deny PG&E's request to recover Account 912 costs?

A. PG&E requested a large increase in marketing costs in its 1996 GRC Application.[124] Page 3 of the 1996 GRC Decision states:

> We deny PG&E's request...for marketing activities which are designed primarily to retain customers as competition in energy markets increases. We find that PG&E's shareholders or affected customers should appropriately assume costs that are incurred to market PG&E services in competitive markets.

Page 39 through 41 of the decision states:

> PG&E seeks ratepayer funding...for marketing programs designed to retain customers. The stated purpose of these programs is to promote the company's long-term business interests, primarily in markets that are competitive or likely to become competitive....In SoCalGas' last general rate case, we reviewed the wisdom of similar marketing programs and concluded the general body of ratepayers should not pay for them....
>
> We have no doubt that PG&E's business retention and development programs are appropriate business activities...but they are only appropriate to the extent that they are funded by shareholders or the customers that benefit from them directly. Without belaboring the issue, utility marketing activities are anticompetitive if they are subsidized by ratepayers in captive markets....
>
> ...We deny funding for these load building and retention efforts because PG&E does not convince us that the general body of ratepayers benefit from them.

[123] 18 CFR, part 201, April 1, 1998 Edition. While the edition used post-dates the 1996 GRC, it is my belief that the definition shown above was in effect in 1995 and 1996.

[124] D.95-12-055, page 37.

The actual costs used to calculate PG&E's return on equity should only include costs that are part of the legitimate cost of providing utility service under the Commission's ratemaking policies. Actual costs should exclude costs that have been explicitly denied rate recovery by the Commission.

The Commission explicitly denied funding for Account 912 costs in the 1996 GRC. The Commission did not disallow the costs because it found PG&E's forecast to be inaccurate. Rate recovery of Account 912 costs was denied completely because the Commission found that those costs did not benefit the general body of ratepayers and should be funded by shareholders. Overland excluded Account 912 costs from actual costs during the GA I period because they had been explicitly disallowed for ratemaking purposes.

Q. Did Mr. O'Louglin exclude some other non-recoverable costs from his actual expenses?

A. Yes. The GA I Settlement disallowed a portion of the capital cost of Line 401. PG&E continues to carry those costs in its regular plant in-service accounts. Mr. O'Loughlin removed the disallowed Line 401 plant costs from his actual rate base and depreciation amounts.

As described in Section 14, PG&E incurred approximately $191 million of non-recoverable chromium remediation costs during the study period. Those costs are assigned to shareholders under the Commission's ratemaking policies. PG&E records those costs in its above-the-line FERC gas transmission O&M accounts.[125] Mr. O'Loughlin removed the disallowed chromium remediation costs from his actual O&M expenses.

Mr. O'Loughlin included the disallowed Account 912 costs in his actual O&M expenses. His treatment of those costs is inconsistent with his treatment of the disallowed Line 401 capital costs and chromium remediation costs.

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[125] Above the line refers to the operating income line on the income statement included in a utility's FERC Form 1 or Form 2 reports. Above the line costs are reflected in operating income, below the line costs are not.

Section 16

Other Actual Expense Differences

Q. What are other actual expenses and why are they relevant?

A. Calculating the return on equity actually earned by GT&S operations requires estimates of all of the components of cost of service. Differences in expenses such as depreciation impact the determination of the actual return on equity earned by GT&S.

Q. Have you prepared a series of tables that show the differences in other expenses?

A. Yes. The first table shows the other expenses used in Overland's calculations of the actual return on equity.

Table 16-1
Other Actual Cost of Service Elements
Per Overland
1999 to 2010
Dollars in Thousands

Year	Distribution	Franchise & Uncollectibles	A&G Expense	Taxes Other Than Income	Depreciation
1999	318	4,533	32,181	17,543	72,295
2000	326	5,071	32,797	17,661	71,792
2001	334	5,899	27,252	17,683	73,154
2002	335	5,292	39,557	18,092	74,069
2003	346	4,600	35,755	19,982	77,270
2004	358	5,150	38,101	20,192	80,570
2005	349	5,333	36,009	20,460	81,770
2006	362	5,766	48,995	21,355	83,891
2007	374	6,068	41,421	22,550	83,191
2008	386	6,303	43,044	23,238	88,391
2009	399	6,506	51,297	22,287	93,391
2010	412	6,466	45,354	25,235	101,091
Total	4,299	66,987	471763	246,278	980,875

Source: Overland Revised Workpaper 5-3

Table 16-2 shows Mr. O'Loughlin's other expense values.

Table 16-2 Other Actual Cost of Service Elements Per O'Loughlin 1999 to 2010 Dollars in Thousands					
Year	Distribution	Franchise & Uncollectibles	A&G Expense	Taxes Other Than Income	Depreciation
1999	0	4,491	32,181	20,021	73,700
2000	0	5,139	32,797	18,480	70,866
2001	0	6,153	27,252	17,862	72,600
2002	0	5,366	39,557	18,243	74,069
2003	0	4,470	35,755	19,698	77,270
2004	365	5,132	38,101	19,671	80,570
2005	408	5,365	36,009	20,546	81,770
2006	416	5,700	48,995	21,203	83,891
2007	424	5,872	41,421	22,101	83,191
2008	426	5,989	43,044	22,765	88,391
2009	429	6,208	51,297	21,799	93,391
2010	427	6,117	45,354	24,796	101,091
Total	2,895	66,002	471,763	247,185	980,800
Source: Exhibit (MPO-7), page 16 and MPO Workpapers, page 39					

Table 16-3 shows the other expense differences.

Table 16-3 Other Actual Cost of Service Elements O'Loughlin Over / (Under) Overland 1999 to 2010 Dollars in Thousands					
Year	Distribution	Franchise & Uncollectibles	A&G Expense	Taxes Other Than Income	Depreciation
1999	(318)	(42)	0	2,478	1,405
2000	(326)	68	0	819	(926)
2001	(334)	254	0	179	(554)
2002	(335)	74	0	151	0
2003	(346)	(130)	0	(284)	0
2004	7	(18)	0	(521)	0
2005	59	32	0	86	0
2006	54	(66)	0	(152)	0
2007	50	(196)	0	(449)	0
2008	40	(314)	0	(473)	0
2009	30	(298)	0	(488)	0
2010	15	(349)	0	(439)	0
Total	(1,404)	(985)	0	907	(75)
Sources: Prior two tables					

Q. What caused the differences in distribution expenses?

A. The distribution expenses represent meter maintenance costs included in distribution Account 890 that are allocable to GT&S.[126] Mr. O'Loughlin excluded those costs from his actual costs in 1999 to 2003.

[126] OC-126.

Overland and O'Loughlin used different data sources for the distribution costs in 2004 to 2010. Overland used the response to OC-126. O'Loughlin used the response to OC-296. The two responses do not agree by the amounts shown above.

Q. Why did Mr. O'Loughlin exclude Account 890 costs during 1997 to 2003?

A. Meter maintenance costs are recovered through the Customer Access Charge. Mr. O'Loughlin refers to the meter maintenance costs as "Maintenance of Measurement and Regulation Station Equipment Costs."

Mr. O'Loughlin excluded the meter maintenance costs from his adopted O&M amounts during 1997 to 2003 based on his theory that the rates adopted in the GA I Settlement did not include a Customer Access Charge.[127] Mr. O'Loughlin excluded meter maintenance costs from his actual costs during 1997 to 2003 to match his adopted amounts.[128]

Q. Are Overland's actual distribution expenses reasonable?

A. Yes. As explained in Section 13, Mr. O'Loughlin's theory that the GA I Settlement did not adopt Customer Access Charges is incorrect. Therefore, meter maintenance costs should be included in actual expenses during 1997 to 2003.

The differences in 2004 to 2010 are very small and have almost no impact on the actual return on equity earned by GT&S operations. Overland's amounts for those years were taken directly from the response to OC-126 and are reasonable.

Q. What caused the differences in Franchise Expense and Uncollectible Accounts expenses?

A. Overland used franchise expense and uncollectible accounts factors from selected GT&S rate cases to calculate actual franchise and uncollectible accounts expenses. The precise data sources used by Overland are identified in Overland's response to PG&E's discovery question 15.

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[127] Exhibit__(MPO-3), page 9.

[128] Exhibit__(MPO-3), page 15.

Mr. O'Loughlin used the franchise and uncollectible accounts expenses from PG&E's December 19, 2011 estimate of the actual return on equity earned by GT&S operations. PG&E took the same general approach as Overland, but was more comprehensive in its review of the prior cases. PG&E's approach is technically superior to Overland's because it incorporated the factors used in each specific case.

Q. Are Overland's actual Franchise and Uncollectible Accounts Expenses reasonable?

A. Yes. The Franchise and Uncollectible Accounts expense differences average $82 thousand per year over the 12 year study period. While Overland's approach is not as detailed as PG&E's, it produces a reasonable result. The differences have virtually no impact on the actual return on equity earned by GT&S operations over the study period. Overland has not modified its results to reflect PG&E's Franchise and Uncollectible Accounts factors.

Q. What caused the differences in Taxes Other Than Income Tax?

A. Overland and O'Loughlin both took total property taxes for the years 2002 to 2010 from the annual GT&S income statements prepared internally by PG&E.[129] The differences in 2002 to 2010 result from small differences in the amount excluded from total property taxes for the portion of Line 401 capital costs disallowed in the GA I Settlement and small differences in payroll tax expense.

The GT&S income statements are not available for 2001 and prior years. Overland set total property taxes in 1999 to 2001 equal to the 2002 amount. Mr. O'Loughlin used the 1999 to 2001 property tax amounts from PG&E's December 19, 2011 estimate of the actual return on equity earned by GT&S operations. PG&E estimated higher total property tax amounts for 1999, 2000 and 2001 than Overland. PG&E has not disclosed the basis for its higher estimates for those years.[130]

[129] The income statements are incomplete and are not prepared on a regulatory accounting basis.

[130] Attachment 2 to the December 19, 2011 supplemental response to OC-83, Property Tax tab indicates the amounts for all years are from the GT&S income statement. However, the responses to OC-276 and OC-286 indicate GT&S income statements are not available for years prior to 2002.

The differences in Taxes Other Than Income Taxes in 1999 to 2001 reflect the higher property tax expenses estimated by PG&E.[131]

Q. Are Overland's actual Taxes Other Than Income amounts reasonable?

A. Yes. The annual differences in Taxes Other Than Income taxes largely offset each other over the twelve year period and do not have a significant impact on the actual return on equity earned by GT&S operations. Overland has not modified its results to conform with Mr. O'Loughlin's estimates.

Q. What caused the differences in Depreciation Expense in 1999 to 2001?

A. Overland and O'Loughlin both took 2002 through 2010 depreciation expense from PG&E's internal GT&S income statements.[132]

Overland set 2001 depreciation expense equal to the 2001 recorded year value reported in the 2004 Test Year GT&S rate case adopted R.O. model. Overland calculated 1999 and 2000 depreciation expense by applying the average 2001 recorded year book depreciation rate to actual 1999 and 2000 average gross plant.

Mr. O'Loughlin used the 1999 to 2001 depreciation expense amounts from PG&E's December 19, 2011 estimate of the actual return on equity earned by GT&S operations. PG&E has not disclosed the basis for its higher estimates for those years.[133]

Q. Are Overland's actual depreciation expense amounts reasonable?

A. Yes. The annual differences in 1999, 2000 and 2001 offset each other and have virtually no impact on the actual return on equity earned by GT&S operations over the study period.

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[131] The differences also include much smaller differences in payroll taxes.

[132] With an adjustment to reduce depreciation expense for the portion of Line 401 capital costs disallowed in the GA I Settlement.

[133] Attachment 2 to the December 19, 2011 supplemental response to OC-83, GT Inc Stat tab.

Section 17

Actual Return On Equity - Income Tax Normalization Policy

Q. Please walk me through the methodology that Mr. O'Loughlin used to calculate the actual return on equity earned by GT&S operations?

A. Mr. O'Loughlin used a multi-step process to calculate the actual return on equity. The steps are shown in the following table.[134]

Table 17-1
O'Loughlin Process for Calculating
Actual Return On Equity

Step	Description
1	Calculate the "Actual Revenue Requirement" using the authorized rate-of-return.
2	Calculate surplus revenues by subtracting the actual revenue requirement from actual revenues.
3	Calculate the income tax liability associated with the surplus revenues by applying statutory income tax rates to the surplus revenues.
4	Calculate surplus operating income by subtracting the income tax liability from the surplus revenues.
5	Calculate surplus rate of return by dividing the surplus operating income by the actual rate base.
6	Calculate the surplus return on equity by dividing the surplus rate of return by the authorized equity ratio.
7	Calculate the actual return on equity by adding the surplus return on equity to the authorized return on equity

Q. Have you prepared a table that illustrates Mr. O'Loughlin's calculations?

A. Yes. The following table summarizes Mr. O'Loughlin's calculations for 2008, 2009 and 2010.

[134] The steps reflect Overland's distillation of the process shown on pages 13 and 16 of Exhibit__(MPO-7).

Table 17-2 Actual Return On Equity Calculations Per O'Loughlin 2008 to 2010 Dollars in Thousands			
Description	2008	2009	2010
Actual Revenues	498,851	514,934	508,524
Actual Revenue Requirement	449,367	469,066	498,486
Surplus Revenues	49,484	45,868	10,038
Statutory Tax Rates (combined)	0.407460	0.407460	0.407460
Income Tax on Surplus Revenue	20,163	18,689	4,090
Surplus Operating Income	29,321	27,179	5,948
Actual Rate Base	1,502,153	1,533,564	1,605,476
Surplus Rate of Return	1.9520	1.7723	0.3705
Authorized Equity Ratio	0.520	0.520	0.520
Surplus Return on Equity	3.7538	3.4082	0.7125
Authorized Return On Equity	11.350	11.350	11.350
Actual Return on Equity per MPO	15.1	14.8	12.1
Source: Exhibit___(MPO-7), page 16 and MPO Workpapers, page 173			

Q. Are the mechanics of Mr. O'Loughlin's multi-step process sound?

A. Yes. However, the accuracy of the results depends on the accuracy of the actual revenues and actual revenue requirement used in the calculations. Mr. O'Loughlin's actual revenue requirements amounts are the product of a defective methodology. Consequently, his results are not accurate.

Q. How did Mr. O'Loughlin calculate his "actual revenue requirements"?

A. Mr. O'Loughlin used the following multi-step process to calculate the actual revenue requirement.[135]

[135] The steps shown below reflect Overland's distillation of the calculations shown on Exhibit__(MPO-7), page 16.

Table 17-3 O'Loughlin Process for Calculating Actual Revenue Requirement	
Step	Description
1	Calculate required operating income by multiplying actual rate base by authorized rate of return
2	Calculate the required after-tax return on equity (both common and preferred) included in the required operating income by applying the weighted cost of equity to the actual rate base.
3	Calculate income tax expense by grossing up the required equity return using a revenue conversion factor based on the combined federal and state statutory income tax rates.
4	Add the calculated income tax expense and actual other operating expenses to the required operating income. The result is the actual revenue requirement.
Source: Exhibit__(MPO-7), page 16	

Q. Have you prepared tables illustrating Mr. O'Loughlin's multi-step process for calculating "actual revenue requirements?"

A. Yes. The following two tables show the calculations for 2008 to 2010. The first table shows the calculation of Mr. O'Loughlin's actual revenue requirements. The second table shows the calculation of the income tax expense included in the first table.

Table 17-4
Actual Revenue Requirement Calculations
Per O'Loughlin
2008 to 2010
Dollars in Thousands

Description	2008	2009	2010
Actual Rate Base	1,502,153	1,533,564	1,605,476
Authorized Rate of Return	0.08790	0.08790	0.08790
Required Operating Income	132,039	134,800	141,121
O&M Excluding A&G	92,384	95,524	110,992
A&G Expenses	43,044	51,297	45,354
Franchise & Uncollectible Expense	5,989	6,208	6,117
Storage Carrying Charges	2,615	2,609	2,603
Taxes Other Than Income	22,765	21,799	24,796
Depreciation	88,391	93,391	101,091
Income Taxes	62,138	63,438	66,413
Rounding	2	0	(1)
Actual Revenue Requirement Per MPO	449,367	469,066	498,486
Source: Exhibit___(MPO-7), page 16			

Table 17-5 Actual Revenue Requirement Calculations - Income Taxes Per O'Loughlin 2008 to 2010 Dollars in Thousands			
Description	2008	2009	2010
Actual Rate Base	1,502,153	1,533,564	1,605,476
Weighted Cost of Equity and Preferred	0.06016	0.06016	0.06016
After Tax Equity Return	90,363	92,253	96,579
Revenue Conversion Factor	1.68765	1.68765	1.68765
Equity Return Grossed Up for Income Tax	152,501	155,691	162,992
Income Taxes	62,138	63,438	66,413
Source: Exhibit___(MPO-7), page 16			

Q. The income tax calculation uses a revenue conversion factor. How is that factor calculated?

A. The revenue conversion factor follows the standard approach used in rate cases to convert a net operating income deficiency into to a gross revenue deficiency. The calculations are shown below.[136]

Table 17-6 Actual Revenue Requirement Calculations Per O'Loughlin Revenue Conversion Factor	
Description	2008
Combined Federal and State Statutory Rate	0.40746
One Minus Combined Statutory Rate	0.59254
One Divided By Line Above	1.68765
Source: Exhibit___(MPO-7), page 16	

Q. Are the mechanics of Mr. O'Loughlin's approach sound?

A. No. The approach that Mr. O'Loughlin used to calculate actual income tax expenses violates the Commissions income tax normalization policy.

Q. Please explain the Commission's income tax normalization policy.

A. The Commission has a long-standing policy of requiring flow-through accounting treatment for book/tax temporary differences to the extent permitted by tax laws, with

[136] The combined federal and state statutory rate reflects the deductibility of state income taxes in the calculation of federal taxable income. The state statutory rate is 8.84 percent. The federal statutory rate is 35 percent. One minus 0.0884 is .9116. That amount times 35 percent is .31906. That amount plus 0.0884 is .40746.

limited exceptions.[137] Federal tax laws require the normalization of federal accelerated depreciation temporary differences for plant placed into service after December 31, 1980.

The Commission's policy is to apply flow-through accounting to:

- Federal accelerated depreciation temporary differences for vintages installed prior to 1981; and
- State accelerated depreciation temporary differences for all vintages.

Q. How does Mr. O'Loughlin's approach violate the Commission's income tax normalization policy?

A. Mr. O'Loughlin's approach ignores all temporary differences between book and taxable income. His approach effectively normalizes all temporary differences by assuming taxable income equals book income. Mr. O'Loughlin admits that his "actual" income tax expenses reflect full normalization of all temporary differences between book and tax income.[138]

Q. Does the Commission's income tax normalization policy apply to Gas Accord cases?

A. Yes. GA I Settlement workpaper 12-2 shows the application of the Commission's income tax normalization policy in that case. The decision in the 2004 GT&S rate case also complied with the Commission's income tax normalization policy.[139] The workpapers for the GA III settlement also show the application of the Commission's income tax normalization policy in the development of the adopted 2005 revenue requirement.[140] PG&E admits the Commission's income tax normalization policy applied to GT&S operations throughout the study period.[141]

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[137] D.84-05-036, Conclusion of Law 6, and Pacific Bell D.04-02-063, February 26, 2004, pages 114 and 115.

[138] OCHP-26.

[139] OC-5, Supplemental Response, Adopted R.O. File RO_Output, Tab Income Tax Summary.

[140] OC-203 .

[141] OC-295.

Q. Why did Mr. O'Loughlin use an approach that violated the Commission's income tax normalization policy?

A. Footnote 9 on Page 4 of Exhibit__(MPO-7) indicates Mr. O'Loughlin assumed full normalization because "any attempt to calculate actual taxes associated with GT&S actual revenue requirement(s) would be difficult and require extensive tax-related data not in the record."

Q. Does assuming full normalization have a significant impact on Mr. O'Loughlin's actual income tax expenses and surplus revenues?

A. Yes. The adopted revenue requirements for 2004 and 2005 and PG&E's litigation forecast revenue requirements for 2008, 2009 and 2010 can be used to illustrate the impact of Mr. O'Louglin's approach.

The following table shows the impact of assuming full normalization using the income tax determinates for those years.[142]

Table 17-7
Impact of Full Normalization Assumption
On Income Tax Expense and Surplus Revenues
Based on Available Rate Case Forecasts
2004 to 2005 and 2008 to 2010

Description	2004	2005	2008	2009	2010
Adopted Rate Base	1,452,043	1,454,012	1,549,838	1,666,827	1,789,988
Weighted Cost of Equity	0.057400	0.059949	0.060200	0.060200	0.060200
Required Operating Income	83,347	87,167	93,300	100,343	107,757
Revenue Conversion Factor	1.68765	1.68765	1.68765	1.68765	1.68765
Equity Return Grossed Up for Income Taxes	140,661	147,107	157,458	169,344	181,857
Income Tax Expense - MPO Method	57,314	59,940	64,158	69,001	74,099
Income Tax Expense - CPUC Policy (From Rate Case Documents)	56,700	60,267	66,280	71,674	79,968
Impact on Income Tax Expense	614	(327)	(2,122)	(2,673)	(5,869)
Gross Revenue Conversion Factor	1.68765	1.68765	1.68765	1.68765	1.68765
Impact on Surplus Revenues	(1,036)	552	3,581	4,511	9,904
Sources: 2004: OC-5, Supplemental; 2005: OC-168 & OC-203; 2008 to 2009: PG&E GA IV R.O. Workpapers					

While the impact varies from year to year, assuming full income tax normalization has a significant impact on surplus revenues over the study period.

[142] The 2008, 2009 and 2010 amounts were taken from the results of operations workpapers that PG&E filed with its Application seeking approval of the GA IV Settlement. The R.O. workpapers supported the litigation forecast, with an increase in book depreciation rates. PG&E's testimony also disclosed the litigation forecast revenue requirement with existing book depreciation rates. However, PG&E did not provide workpapers supporting the litigation forecast with existing book depreciation rates. The data shown in the table is from the R.O. workpapers with the increased book depreciation rates.

Q. Why does assuming full normalization decrease income tax expense and increase surplus revenues?

A. Under CPUC policy, plant vintages installed prior to 1981 are accounted for on a flow through basis for both federal and state income tax purposes. The plant included in those vintages has exceeded its tax life. As a result, current taxable income is not reduced by any tax depreciation deductions for that plant.

Under full normalization accounting, once the tax life of a vintage has ended, the deferred tax liabilities that were accrued when the plant was still in its tax life are amortized over the remaining book life of the vintage. That amortization reduces deferred income tax expense.

Because the pre-1981 vintages were accounted for on a flow-through basis during their tax lives, there is no accumulated deferred tax liability recorded on the books to amortize. Under flow-through accounting, vintages that have exceeded their tax life have a higher current year total income tax expense than they would have in the current year under normalization accounting. [143]

Q. How would assuming full income tax normalization of all book/tax temporary differences impact Overland's surplus revenue results?

A. I created an alternative case by adjusting Overland revised workpapers 5-1 to 5-4 to reflect full normalization and compared that to Overland's base case to determine the impact of a full normalization assumption. The following table shows the impact that assuming full normalization would have on Overland's actual income tax expense and surplus revenue amounts.

[143] The tax liability for the current year is the same under flow-through and normalization. Under flow through the vintage has zero deferred income tax expense. Under normalization the vintage has negative deferred income tax expense. Consequently, the total income tax expense (current plus deferred) is higher under flow through accounting.

Table 17-8 Impact of Assuming Full Income Tax Normalization On Overland Actual Income Tax Expense And Surplus Revenue Dollars in Thousands			
Year	Income Tax Expense	Conversion Factor	Surplus Revenues
1999	(6,993)	1.68765	11,802
2000	(8,359)	1.68765	14,108
2001	(7,474)	1.68765	12,614
2002	(2,913)	1.68765	4,916
2003	(3,189)	1.68765	5,381
2004	(7,632)	1.68765	12,881
2005	(5,497)	1.68765	9,278
2006	(5,471)	1.68765	9,233
2007	(4,460)	1.68765	7,527
2008	(3,172)	1.68765	5,352
2009	(3,634)	1.68765	6,133
2010	(3,122)	1.68765	5,268
Total	(61,916)	1.68765	104,493
Source: Calculated From Overland Revised Workpapers 5-1 to 5-4			

Assuming full income tax normalization would reduce actual income tax expense by $62 million and increase surplus revenues by $104 million. Under the full normalization assumption, Overland's surplus revenues amount would increase from $435.2 million to $539.7 million over the study period.

Q. Is Overland's approach to calculating actual income tax expense reasonable?

A. Yes. Overland's approach is consistent with the Commission's income tax normalization policy. As shown above, Overland's approach increases income tax expense by $61.9 million over the twelve year study period compared to assuming full normalization. The average annual increase in income tax expense of $5.16 million a year is a plausible estimate of the impact of the Commission's income tax normalization policy on annual GT&S income tax expense.

Overland's actual income tax expense calculations include an adjustment to increase income tax expense to reflect federal flow-through accounting for pre-1981 vintages. That adjustment is calculated on Overland workpaper 5-5 and applied on Overland workpaper 5-4. The adjustment was necessary because PG&E could not provide actual GT&S deferred income tax expenses for the study period.[144]

[144] OC-295.

The adjustment for flow-through vintages is based on assumed plant costs for the pre-1981 flow-through vintages and professional judgment. Overland used very conservative assumptions that increased income tax expense to avoid overstating surplus revenues. Using less conservative assumptions would produce results that are closer to Mr. O'Loughlin's results.

Section 18

Surplus Revenues

Q. On page 7 of his testimony, Mr. O'Loughlin indicates that the actual ROE for PG&E's GT&S operations averaged 14.6% during 1999 to 2010. Is that similar to what you found?

A. Yes. As shown on Overland Revised Table 5-1, the actual ROE for PG&E's GT&S operations averaged 14.3% during the same period.[145] The difference between the two ROE figures is due to the income tax normalization issue discussed in Section 17, and all of the other errors Mr. O'Loughlin made when determining actual revenues and expenses. The largest of those errors were: (1) excluding $29.7 million in customer access charge revenues from actual revenue in 1999 to 2002; (2) including $27.4 million of disallowed Sales expenses in actual O&M during 1999 to 2002; and (3) including $21.8 million in non-recoverable SBI expenses in his actual O&M for 2010.[146]

Q. On page 60 of his testimony, Mr. O'Louglin indicates that GT&S's high ROEs are entirely the result of actual revenues exceeding adopted revenues. Do you agree with that conclusion?

A. No. Mr. O'Loughlin determined that actual GT&S revenues exceeded the amount needed to earn the authorized ROE by $479.5 million during the period 1999 to 2010.[147] He also claims that actual revenues exceeded adopted revenue requirements by $515.5 million during the same period.[148] Based largely on that comparison, Mr. O'Loughlin concludes that all of PG&E's excess earnings were the result of actual revenues exceeding adopted revenues. That conclusion is invalid because his comparison of actual and adopted revenues is invalid.

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[145] Section 3, Overland Revised Table 5-1. The tables in Section 3 show both the original table number from the Overland Report and a new table number the corresponds with the sequence of tables in Section 3. Overland Revised Table 5-1 is also Table 3-5 in Section 3. Overland acknowledges that having two different table numbers on the same table is somewhat confusing.

[146] Sections 13, 14 and 15.

[147] Exhibit__(MPO-1), page 66.

[148] Exhibit__ (MPO-1), page 64.

As shown on Overland Revised Table 5-3, actual revenues only exceeded adopted revenues by $244 million during 1999 to 2010. That leaves significantly more than $235 million of Mr. O'Loughlin's surplus revenues to be explained by other factors.[149]

Q. Why is Mr. O'Loughlin's comparison of actual revenues to adopted revenue requirements invalid?

A. As explained in Section 12, the adopted revenue requirements used in Mr. O'Loughlin's comparison are incorrect. Mr. O'Loughlin's 1999 to 2003 adopted revenues reflect his theory that approximately half of Line 401 revenue requirements were excluded from the revenue requirements adopted in the GA I Settlement. That theory is wrong for the reasons explained in Section 4.

Mr. O'Loughlin uses his erroneous comparison of adopted and actual revenues to explain away the high ROEs earned by GT&S operations, and avoid admitting that actual O&M and capital expenditures were lower than the adopted values.

Q. How does correcting Mr. O'Loughlin's revenue comparison leave significantly more than $235 million of his surplus revenues unexplained?

A. After Mr. O'Loughlin's revenue comparison is corrected, it only explains $244 million of his $479.5 million in surplus revenues. Mr. O'Loughlin claims that PG&E overspent $21.5 million on O&M and $305 million on capital expenditures during 1999 to 2010.[150] Overspending of that magnitude would significantly reduce the actual ROE earned by GT&S operations and the corresponding surplus revenues. Therefore, if Mr. O'Loughlin's claims of overspending are correct, his surplus revenues should be significantly less than the corrected $244 million revenue difference.

Mr. O'Loughlin's comparisons of actual and adopted revenues and expenditures do not come close to explaining his finding of $479.5 million in surplus revenues. The unexplained gap demonstrates the inaccuracy of his claims of over-spending.

[149] $479.5 million minus $244.0 million is $235.5 million.

[150] Exhibit__(MPO-1), pages 19 and 43. The totals on those pages are higher than the amounts shown above because they include 1997 and 1998.

Q. Page 5-3 of Overland's report cites four factors that contributed to the high ROE earned by GT&S operations during the study period. Do those factors remain valid?

A. Yes. Overland's revised tables changed the amounts cited in the first and third factors shown on Page 5-3 of the Overland Report by relatively modest amounts.[151] Those changes do not change the substance of Overland's findings.

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[151] The revenue difference cited in the first factor changes from $224 million to $244 million. The 1997 to 2000 capex difference cited in the second factor changes from $94 million to $102 million.

Section 19

PG&E's "At-Risk" Storage Business

Q. On page 64 of his testimony, Mr. O'Loughlin indicates that actual storage revenues exceeded adopted storage revenues by $397.7 million over the period 1999 to 2010. Is that consistent with what Overland found?

A. Yes, for the most part. Schedule 5-1 of the Overland Report indicates actual storage revenues exceeded adopted storage revenues by $334.6 million over the same period.[152] The actual storage revenues shown in the Overland report exclude some storage carrying charge revenues. Overland accepted Mr. O'Loughlin's adjustment to include those storage carrying charges in actual revenues.[153] After making that change, Overland's actual storage revenues exceed adopted storage revenues by $368 million.[154]

Q. Did PG&E's storage operations earn a very high ROE during the study period?

A. Yes. In particular, PG&E's "at-risk" storage business earned extremely high profits during that period.

Q. What is PG&E's "at-risk" storage business?

A. PG&E's storage revenue requirements are assigned to three unbundled rate categories in the Gas Accord proceedings. The largest category is storage for core customers. That storage is used to provide peak day reliability to core customers during the winter heating season. The next largest category is transmission balancing. Transmission balancing storage provides for the differences between the amounts of gas injected into the transmission system each day and the amounts withdrawn from the system by customers. Transmission balancing costs are included in transmission rates.

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[152] Schedule 5-1 should not be confused with Table 5-1. Schedule 5-1 shows revenue differences by function.

[153] Section 3, Overland Revised Tables.

[154] The difference between Overland's revised amount of $368 million and Mr. O"Loughlin's difference of $397.7 million may be, at least partially, a result of Mr. O'Loughlin's allocation of Other Revenues (including Other Operating Revenues) to the transmission and storage functions. Overland did not allocate those revenues to transmission and storage on Schedule 5-1.

Mr. O'Loughlin refers to the third category as "at-risk" storage. That category consists largely of "parking and lending" services provided to gas marketers and other utilities. The "at-risk" services also included much smaller quantities of firm storage services and non-firm as-available storage services.

Q. Have you prepared tables showing the allocation of the storage revenue requirement to those three categories?

A. Yes. The following table shows the adopted allocations for 1997, 2004 and 2005.

Table 19-1
Adopted Storage Revenue Requirement
By Component
1997, 2004 and 2005
Dollars in Thousands

Category	1997	2004	2005
Core Storage	39,764	38,454	41,488
Transmission Balancing	5,262	9,330	9,970
At-Risk Storage	5,470	6,795	7,331
Total	50,496	54,579	58,789
Percent Core Storage & Balancing	89.17	87.55	87.53
Percent At-Risk Storage	10.83	12.45	12.47
Sources: OCHP-2, OCHP-3 and D.03-12-061, Appendix A, page 29			

The 1997 allocation also applies to 1998 through 2002 since the rates in those years were calculated by escalating 1997 rates at a negotiated rate. The 2005 allocation applies to 2006 and 2007 for the same reason.

As shown above, approximately 88 percent of the total storage revenue requirement was allocated to core storage and transmission (balancing) during the period 1997 to 2010.

Q. Have you prepared a table showing the revenues produced by the "at-risk" storage services by type of service?

A. Yes. The following tables shows the actual "at-risk" storage revenues by category for the period 2004 to 2010.[155]

[155] 1997 to 2002 are omitted because the information is not available in the Revenue Monitoring reports or cannot be verified using PG&E's GA data books. 2003 is omitted from the table to match the revenue comparison shown in a following table.

Table 19-2 Actual Storage Revenue By Component 2004 to 2010 Dollars in Thousands				
Year	Firm and As Available Storage	Park & Lend	Accounting Reserve	Total
2004	3,620	27,240	(1,580)	29,280
2005	1,320	48,170	(840)	48,650
2006	430	59,220	3,570	63,220
2007	1,100	67,870	(5,390)	63,580
2008	1,160	67,570	(9,660)	59,070
2009	1,170	75,870	(5,960)	71,080
2010	930	38,180	20,400	59,510
Total	9,730	384,120	540	394,390
Sources: OC-82, December Revenue Monitoring Reports and OCHP-37, attach 2 and 4.				

Parking and lending revenues accounted for 97.4 percent of the total "at-risk" storage revenue during the seven year period shown above. PG&E's "at-risk" storage business is in substance a parking and lending business.

The accounting reserve is an accrual mechanism that is used to smooth out fluctuations in earnings between years. If the accounting reserve is excluded from the total, parking and lending revenues accounted for 97.5 percent of "at-risk" storage revenues over the seven year period.

Q. What is parking?

A. Parking and lending are two different services.[156] The GA I Settlement defines parking service as "short-term parking service, using PG&E's transmission and storage system."[157] PG&E's Gas Schedule G-PARK defines parking as "the temporary storage of gas on the PG&E gas transmission system."[158]

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[156] OCHP-5 and OCHP-6.

[157] GA I Settlement, page 17, Section II. D.

[158] OCHP-5 and 6.

Under the parking service a customer delivers a pre-arranged quantity of gas to delivery points on PG&E's transmission system and receives the same quantity of gas at the same delivery point at a pre-arranged future date. Parking service allows the customer to purchase gas in the late summer and early fall when commodity prices are low, and park the gas on PG&E's transmission system until the winter heating season when prices are high.

Q. What is lending?

A. The GA I Settlement defines lending service as a "as-available short-term loan of gas using PG&E's transmission and storage system."[159] PG&E's Gas Schedule G-Lend defines lending as "the temporary loan of gas from the PG&E gas transmission system."[160]

Under the lending service, PG&E delivers a pre-arranged quantity of gas to delivery points on PG&E's transmission system and the customer returns the borrowed gas to PG&E at the same delivery point at a pre-arranged date in the future. Lending service allows customers to borrow gas quantities from PG&E's transmission system when commodity prices are high, and repay them when prices are lower.

Q. Do the G-Park and G-Lend Gas Schedules restrict the delivery points for parking and lending services?

A. Yes. Gas Schedules G-Park and G-Line restrict the delivery points for the parking and lending services to the following general categories:

> The points of service for parking (and lending) are the various locations at which PG&E's system interconnects with interstate pipelines, at Kern River station, and at PG&E's citygate.

The parking and lending services do not require the customer to arrange for the transportation of the gas to or from PG&E's storage facilities. Instead, the gas is

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[159] GA I Settlement, page 17, Section II. D.

[160] OCHP-5 and OCHP-6.

received from or delivered to PG&E's transmission system at the points specified in the Gas Schedules.

Q. Did PG&E classify parking and lending services as transmission services in its testimony in the GA I case?

A. Yes. PG&E's August 21, 1996 Report on the Gas Accord Settlement Agreement describes parking and lending services in Chapter 3, Transmission Services, under the heading "Other Transmission Services." That testimony describes parking and lending as "short-term flexible market services." [161] PG&E's testimony indicates the parking and lending services promote "more efficient use of the utility system."

Chapter 6 of PG&E's Report on the Gas Accord Settlement Agreement describes storage services. That chapter does not contain the words parking or lending in any form.

Section II of the Gas Accord I Settlement includes lists of the services available under the Gas Accord. Parking and lending services are included in the list for "Other Services" instead of the separate lists for transmission and storage services.[162] The evidence clearly demonstrates that parking and lending services utilize both transmission and storage facilities.

Q. Why do you believe that the profits earned by PG&E's at-risk storage services were extremely high during the study period?

A. Mr. O'Loughlin estimates that PG&E's storage function earned a 32.3 percent ROE during the study period.[163] Approximately 88 percent of the adopted storage revenue requirement was allocated to core storage and transmission balancing during the study period.

Core storage and balancing are not competitive services and PG&E does not have pricing flexibility for those services. Core storage and balancing do not provide any

[161] PG&E Report on the Gas Accord Settlement Agreement, August 21, 1996, page 3-3.

[162] GA I Settlement, Sections II, parts A to D.

[163] Exhibit___(MPO-1), page 67.

significant opportunities to increase profits through marketing efforts. Adopted Core storage revenue requirements are recovered on a dollar for dollar basis from core customers. Balancing costs are recovered through transmission rates. Given the relative stability of their revenue streams, it is reasonable to conclude that core storage and balancing did not earn significantly more than their authorized return on equity. According to Mr. O'Loughlin, the storage business as a whole earned a 32 percent ROE. Therefore, the "at-risk" storage services must have earned an extremely high ROE.

Q. Have you prepared a table that compares actual "at-risk" storage revenues to adopted "at-risk" storage revenues?

A. Yes. The following table makes that comparison for the period 2004 to 2010.

Table 19-3
Comparison of Adopted and Actual At Risk Storage Revenues
By Year
2004 to 2010
Dollars in Thousands

Year	Actual	Adopted	Difference
2004	29,280	6,795	22,485
2005	48,650	7,331	41,319
2006	63,220	7,598	55,622
2007	63,580	7,750	55,830
2008	59,070	7,750	51,320
2009	71,080	7,750	63,330
2010	59,510	7,750	51,760
Total	394,390	52,724	341,666

Source: OCHP-36 and GA IV Settlement, Appendix A, Table A-4

Actual at-risk storage revenues exceeded adopted at-risk storage revenues by $342 million during that seven year period.

Q. Have you prepared some rough estimates of the actual ROE for PG&E's "at-risk" storage services?

A. Yes. A rough estimate of the actual ROE earned by PG&E's "at-risk" storage business can be prepared for some years using Mr. O'Loughlin's methodology and making a couple of assumptions to account for values that are not available. [164] Mr. O'Loughlin's

[164] Mr. O'Loughlin's methodology for calculating actual ROE is described in Section 17.

methodology requires values for the "actual revenue requirement" and the actual rate base. Those values are not available by storage category. My calculations use the adopted at-risk storage revenue requirement and the adopted rate base as proxies for those values.

The following table shows the calculation of my rough estimate of the actual ROEs earned by PG&E's "at-risk" storage operations during the years 2004, 2005 and 2008.

Table 19-4
Rough Estimate of At-Risk Storage
Actual Return on Equity
2004, 2005 and 2008
Dollars in Thousands

Description	2004	2005	2008
Revenues in Excess of Adopted	22,485	41,319	51,320
One Minus Income Tax Rate	0.59254	0.59254	0.59254
Net of Tax Surplus Revenue	13,323	24,483	30,409
Estimated Rate Base	17,546	22,513	32,274
Surplus Rate of Return	75.93	108.75	94.22
Authorized Equity Ratio	0.490	0.520	0.520
Surplus Return on Equity	154.96	209.14	181.20
Authorized Return on Equity	11.22	11.22	11.35
Estimated Actual ROE	166.18	220.36	192.55
Source: MPO Workpaper Page 173 and the Surplus Revenue and Rate Base Tables in this Section			

The rough estimates indicate that the actual ROEs for PG&E's "at-risk" storage operations were extremely high in 2004, 2005 and 2008.

Q. How did you calculate the adopted rate base amounts for at-risk storage?

A. I allocated total adopted storage rate base to at-risk storage using the adopted 2004, 2005 and 2008 storage revenue requirements shown on the prior table. The rate base allocations are shown below.

Table 19-5 Rough Estimate of At-Risk Storage Actual Rate Base 2004, 2005 and 2008 Dollars in Thousands			
Description	2004	2005	2008
Adopted Total Storage Rate Base	161,977	180,827	258,809
Percent At Risk Storage	10.83	12.45	12.47
Estimated At Risk Rate Base	17,546	22,513	32,274
Source: D.03-12-061, Appendix A, Table 2; OC-168 and OC-2, GA IV R.O. workpapers, page 375			

Q. Mr. O'Loughlin places a great deal of emphasis on the fact that PG&E's storage business produced a significant portion of the excess profits made by GT&S. Is that emphasis appropriate?

A. No. Approximately 88 percent of the storage revenue requirement was charged to core and other transmission customers through core storage and balancing charges during the study period.[165] Since the same customer groups pay most of the costs of both functions, distinguishing between storage and transmission profits is not particularly meaningful.

Q. Are PG&E's storage and transmission facilities part of the same integrated system?

A. Yes. Storage and transmission are part of an integrated system for serving on-system customer load. PG&E's storage facilities were constructed primarily to provide reliable service to core customers.[166] One of the goals of GA I Settlement was to "continue operational integration of PG&E's gas storage facilities with PG&E's transmission facilities."[167] Storage depends on transmission for gas transportation and transmission depends on storage for peak day reliability and balancing.

PG&E's at-risk storage business is primarily a parking and lending business. The parking and lending business utilizes PG&E's transmission facilities. PG&E's parking and lending services depend on the use of its transmission system.

[165] Core customers are also firm transmission customers.

[166] 2004 GT&S Rate Case Decision 03-12-061, page 245.

[167] GA I Settlement, page 5.

The integrated nature of PG&E's storage and transmission facilities supports my conclusion that distinguishing storage profits from transmission profits is not particularly meaningful.

Q. Has PG&E linked storage profits to transmission cost recovery in Gas Accord testimony?

A. Yes. Prior to 2011, PG&E did not share any of the profits made by its "at-risk" storage business with ratepayers. PG&E directly linked that lack of sharing to transmission cost recovery in its March 2007 testimony in support of the GA IV Settlement. That testimony states:[168]

> ...PG&E's negotiations with parties since the original Gas Accord have always allowed PG&E to fully retain any excess storage revenues. This recognizes the considerable risk PG&E bears in collecting sufficient revenues to cover its costs through the backbone and local transmission rates negotiated as part of an integrated settlement agreement.

According to PG&E, the possibility of high storage profits was intended to compensate PG&E for transmission cost recovery risks it accepted in the Gas Accord Settlements. That supports my conclusion that distinguishing between storage and transmission profits is not particularly meaningful.

Q. You indicated that prior to 2011 storage profits were not shared with PG&E ratepayers. What changed in 2011?

A. PG&E proposed a sharing mechanism in its 2011 Test Year Rate Case Application.[169] PG&E's sharing proposal covered all GT&S revenues and provided for surcharges when actual revenues were below the adopted amount and refunds when actual revenues exceeded adopted. Under PG&E's proposal, the revenue differences would be shared with customers on a 50/50 basis. The sharing would be implemented through adjustments to backbone transmission rates.[170] PG&E's proposal to credit storage excess revenues to firm transmission customers, demonstrates the linkage between storage profits and firm transmission.

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[168] PG&E Testimony Supporting the Gas Accord IV Settlement, March 17, 2007, page 18.

[169] D.11-04-031, page 32.

[170] PG&E Testimony in 2011 GT&S case, Chapter 9, Cost Recovery and Revenue Sharing Mechanisms, pages 9-2 and 9-3.

Section 10.1 of the GA IV Settlement adopted a sharing mechanism that was different than PG&E's proposal. The settlement provided different sharing percentages for backbone transmission, local transmission and storage. The backbone and local transmission sharing is two-way sharing with surcharges for undercollections and refunds for over-collections. The storage sharing credits 75 percent of over-collections to ratepayers. Storage undercollections are absorbed entirely by shareholders.

The simultaneous implementation of sharing for transmission and storage demonstrates the linkage between storage profits and transmission cost recovery in Gas Accord cases. The asymmetrical sharing of storage over-collections and undercollections demonstrates that shareholders are not entitled to a privileged status in allocations of storage profits between shareholders and ratepayers.

Under the GA V Settlement, the surcharges and rate refunds resulting from the sharing mechanism are made through the Customer Class Charge. The Customer Class Charge only applies to on-system customers. The settlement provides for a 50/50 allocation of the rate adjustments between core and noncore. The settling parties apparently recognized that storage over collections should be credited only to on-system customers. That is consistent with the reason why the storage facilities were built, the assignment of storage revenue requirements to customer groups in Gas Accord rates, and the role of storage in PG&E's integrated system. The treatment of storage sharing rate adjustments in the GA IV settlement demonstrates the linkage between storage profits and transmission cost responsibility.

Q. Does the Joint Testimony in Support of the GA V settlement confirm the linkage between storage profits and transmission cost recovery?

A. Yes. Page 22 of that testimony indicates:[171]

> Market Storage revenues have typically exceeded allocated costs, and gas transmission rates have typically been set at levels that did not allow PG&E to recover its full cost of service. In practical terms, previous Gas Accords have contained informal revenue sharing mechanisms.

[171] OCHP-37, Attachment 6.

In other words, PG&E was allowed to retain excess storage profits as compensation for transmission cost recovery risks assigned to PG&E in the Gas Accord Settlements. The Joint Testimony is another clear indication of the linkage between the treatment of storage profits and transmission cost recovery.

Q. Has the Commission shared storage profits with core and other firm transmission customers in cases involving other utilities?

A. Yes. SoCalGas has shared the net revenues produced by its "unbundled storage program" with on-system (core and non-core) transmission customers for many years.[172] SoCalGas's unbundled storage program services are comparable to PG&E's "at-risk" storage services. Net revenues are the difference between gross revenues and the cost of providing service. The SoCalGas sharing mechanism is consistent with the linkage between storage profits and transmission cost recovery.

Q. Is assigning excess storage profits to transmission customers fair?

A. Yes. PG&E's "at-risk" storage business is essentially a parking and lending business that makes extensive use of PG&E's transmission and storage facilities. Parking and lending services are short-term opportunity transactions. The park and lend transactions are typically short-term in duration and depend on the spread between expected gas prices in different seasons of the year.[173]

The customer groups that pay for a system should be credited with the benefits produced by that system, including margins made on short-term opportunity transactions. Crediting parking and lending margins to firm transmission (and core) customers is fair because the rates they pay recover almost all of the fixed costs of PG&E's transmission and storage system.[174]

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[172] OCHP-38.

[173] OCHP-5 and 6.

[174] The purpose of a sharing margins made on short-term opportunity transactions with shareholders is to provide the utility with an incentive to actively market those services. The sharing mechanism benefits ratepayers if the increase in total net margins produced by the incentive exceeds the amount of the profits retained by shareholders. Sharing can also benefit consumers by stimulating active market participation by the utility.

Q. Did the Gas Accord Settlements allow PG&E to retain the margins produced by parking and lending services during the study period?

A. Yes. However, the Gas Accord Settlements also allowed PG&E to retain the margins produced by its backbone and local transmission services. Prior to 2011, the Gas Accord Decisions and Settlements gave "at-risk" storage and transmission margins the same treatment. Mr. O'Loughlin's misguided efforts to distinguish between transmission and storage profits do not change the fact that the Gas Accord rates charged to customers significantly over-recovered the actual cost of providing service during the study period.

Section 20

PG&E's Total Company Return On Equity

Q. Mr. O'Loughlin reviews PG&E's total company ROE during the study period on pages 79 to 83 of his testimony. Did you review PG&E's total company ROE during the audit?

A. No. The scope of Overland's audit was limited to GT&S operations.

Q. Mr. O'Loughlin's testimony includes a table on page 80 showing total utility "recorded ROE" by year for 1999 to 2010. Do you have any comments about that table?

A. Yes. Mr. O'Loughlin's total company ROE figure were taken from annual earnings reports that PG&E submits to the CPUC.[175] My cursory review of those annual earnings reports identified several issues.

First, the gas department rate base totals shown on the annual earnings reports have not been reduced to remove the Line 401 plant costs that were disallowed in the GA I Settlement.[176] Second, the gas transmission O&M expenses shown on the annual earnings reports include the non-recoverable chromium remediation costs described previously in my testimony. Third, the results for 2000 to 2003 may be distorted as a result of the California Energy Crises and PG&E's bankruptcy proceeding. Fourth, the reports for 1998 to 2001 indicate they exclude Diablo Canyon.

Q. How did you determine that the rate base amounts include the portion of Line 401 that was disallowed in the GA I Settlement?

A. The rate base amounts for the gas department agree with the amounts shown on PG&E's Recorded Rate Base Reports in nine of the twelve years during the study period.[177] Overland used the recorded rate base reports in its audit to calculate actual

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[175] The annual earnings reports are shown on Exhibit __(MPO-38).

[176] The annual earnings reports also include gas department depreciation expense. It is reasonable to assume that the depreciation expenses shown on those reports have not been reduced to eliminate depreciation on the disallowed plant because the disallowed plant costs are included in the rate base amounts shown on the reports.

[177] OCHP-39, OC-83 and OC-178.

rate base. The plant in service amounts shown on the recorded rate base reports include the Line 401 plant costs that were disallowed in the GA I Settlement.[178]

Q. How did you determine that the gas transmission expenses shown on the annual earnings reports include non-recoverable chromium remediation costs?

A. PG&E includes the chromium remediation costs in the gas transmission O&M expenses reported in its FERC Form 2 report. The gas transmission expense amounts shown on the annual earnings reports agree with the FERC Form 2 for seven of the twelve years in the study period.[179] The annual earnings reports do not show gas transmission expense separately in three of the other years.[180] The annual earnings reports show higher gas transmission expense than the FERC Form 2 in the other two years.[181]

The gas department transmission expenses shown on the annual earnings reports include large amounts of non-recoverable chromium remediation costs. For example, the 2005 transmission expenses reported in the FERC Form 2 included $45 million in non-recoverable chromium remediation costs.[182] The 2005 gas transmission O&M expenses shown in the FERC Form 2 agree exactly with the gas transmission expenses shown on the 2005 earnings report.

Q. Why do you believe that the earnings shown for 2000 to 2003 may have been distorted by the California Energy Crises and PG&E's bankruptcy proceeding?

A. The California Energy crises began in the spring of 2000 and ultimately resulted in PG&E filing for bankruptcy on April 6, 2001. The Commission approved a settlement designed to allow PG&E to emerge quickly from bankruptcy protection in December 2003.[183]

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[178] In other words, the rate base amounts shown in the recorded rate base reports have not been reduced to reflect the disallowance of the costs.

[179] 1999, 2000, 2001, 2002, 2005, 2006, and 2008.

[180] 2007, 2009 and 2010.

[181] 2003 and 2004.

[182] OC-296, MWC JG, and 2005 FERC Form 2, page 324.

[183] D.03-12-035, dated December 19, 2003.

Note (2) on the 2003 annual earnings reports describes significant bankruptcy related adjustments that impacted reported earnings during the years 2000 to 2003.

In addition to those adjustments, PG&E incurred $412 million in bankruptcy costs during that time period. Those costs were primarily professional services costs.[184]

Q. Did Mr. O'Loughlin audit the annual earnings reports?

A. No. On page 79, footnote 127, Mr. O'Loughlin indicates that the reports were prepared by PG&E and he has not "reviewed the details" behind the reports.

Q. Should the Commission view Mr. O'Loughlin's total company ROE amounts with skepticism?

A. Yes. My cursory review identified two significant problems with the earnings reports pertaining to gas transmission and storage. I was able to identify those problems because of the knowledge of PG&E's GT&S operations that I obtained during the audit. I have not audited PG&E's electric operations. There may be similar problems pertaining to electric operations that I have not identified because of my limited knowledge of those operations.

Q. Does that conclude your rebuttal testimony?

A. Yes.

[184] PG&E 2003 10-K Report, Management Discussion and Analysis of Financial Condition and Results of Operations, page 18. That page is shown on PDF page 347 of the 2003 10-K report on PG&E's web-site.

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General

Mr. Harpster specializes in the areas of regulatory accounting and ratemaking for electric and gas utilities. He is a certified public accountant and holds a Bachelor of Science degree in Business Administration in Accounting from Central Missouri State University.

Mr. Harpster has thirty-three years of experience as a public utility regulatory consultant. He has presented expert testimony in more than thirty-five proceedings before the FERC, state commissions in Arizona, California, Indiana, Kansas, Kentucky, Massachusetts, Michigan, Missouri, New Jersey, Ohio and Virginia, and courts in Arizona, Iowa and Louisiana.

Experience

- Project manager for Overland's focused audit of the gas transmission safety-related expenditures of the Pacific Gas & Electric Company on behalf of the California Public Utilities Commission (2011).
- Technical manager for Overland's management audit of Public Service Electric & Gas on behalf of the New Jersey Board of Public Utilities (Power Supply) (2010).
- Technical advisor for Overland's review of EDF's potential acquisition of substantial influence over Constellation Energy Group on behalf of the Maryland Public Service Commission (2009).
- Technical manager for Overland's management audit of the Atlantic City Electric Company on behalf of the New Jersey Board of Public Utilities (Power Supply, Electric System Operations and Human Resources) (2008).
- Technical manager for Overland's audit of the earning of Verizon on behalf of the California Public Utilities Commission (2007).
- Technical manager for Overland's review of the proposed merger between Exelon and PSEG on behalf of the New Jersey Board of Public Utilities (2005).
- Technical manager for Overland's valuation of power plants on behalf of the Virginia State Corporation Commission (2004).
- Technical manager for Overland's audit of the earnings of Citizens Communications on behalf of the California Public Utilities Commission (2004).
- Project Manager for Overland's audit of the Pacific Gas & Electric Company's administrative and general expenses in two general rate cases on behalf of the California Public Utilities Commission (2003 and 1999).
- Technical manager for a multi-year regulatory audit of the Pacific Bell Telephone Company on behalf of the California Public Utilities Commission (2000-2003).

- Project manager for a review of power plant valuation methods on behalf of the Arizona Department of Revenue (2000-2001).

- Reviewed the impact of major FASB accounting pronouncements on the valuation of electric and gas utilities on behalf of the Iowa Department of Revenue (2001).

- One of two project managers for Overland's audit of the Pacific Gas & Electric Company's affiliate transactions (1997-1998).

- Technical manager for an audit of the Southern California Gas Company's performance based management (PBR) incentive rate plan application (1996).

- Project manager for the development of a continuing property records system for a natural gas pipeline (1999-2000).

- Project manager for a review of four electric and gas utility property tax issues on behalf of the Arizona Department of Revenue (1999).

- Project manager for a review of Boston Edison's transactions with its telecommunications affiliate RCN-Beco Com (1998-1999).

- Project manager for a review of the Tucson Electric Power Company's proposal to form a holding company on behalf of the Arizona Corporation Commission Staff (1995).

- Project manager responsible for the determination of electric utility cost of service in three Tucson Electric Power Company rate cases on behalf of the Arizona Corporation Commission Staff (1996, 1993 and 1989).

- Project manager for a regulatory compliance audit of the construction and operating costs of Pacific Gas & Electric Company's Pipeline Expansion Project, an $800 million gas pipeline completed in November 1993 (1994 and 1995).

- Project manager for a study of the prudence of the decision of KPL/Gas Service to enter into a firm gas supply contract with the Kansas Pipeline Operating Company (1992 - 1995).

- Project Manager for a review of the Detroit Edison Company's ten-year special manufacturing contracts with Ford, General Motors and Chrysler (1994).

- Technical manager for a rate case audit of Transok, Inc., an intrastate gas pipeline (1994).

- Project manager for a focused management audit of the fuel procurement practices of the Big Rivers Electric Corporation (1993).

- Project manager responsible for quantifying damages in bid-rigging litigation concerning the construction of the Cajun Electric Cooperative Big Cajun No. 2 Unit 3 (540 MW coal-fixed generating unit) (1990 - 1993).

- Instructor in a training seminar for the Kentucky Public Service Commission concerning the use of projected test years (1992).

- Project manager for an audit on behalf of the Kansas Corporation Commission of a gas distribution base rate application filed by the Arkansas Louisiana Gas Company (1992).

- Project manager for an audit on behalf of the Kansas Corporation Commission of a gas distribution base rate application filed by the Kansas Power & Light Company (1991).

- Participated in a study of the reasonable original cost of the Zimmer Generating Station which had originally been designed, constructed and abandoned as a nuclear facility and was subsequently completed as a coal-fired facility (1991).

- Project manager responsible for a study of the impact of environmental regulations on the cost of constructing the Palo Verde Nuclear Station, a 3,750 MW nuclear generating station. This analysis was used in connection with a valuation determination for property tax purposes (1991).

- Project manager for several Fuel Adjustment Clause Compliance Audits of Consumers Power Company and Detroit Edison Company (1983 - 1991).

- Project manager responsible for evaluating a wholesale power sale agreement between Century Power Corporation and Tucson Electric Power Company (FERC 1990).

- Project manager for a management audit of the gas production, transmission and marketing functions of the Johnson County Industrial Airport (Kansas) (1990).

- Project manager responsible for a prudence review of Consumers Power Corporation's decision to spin-off the Palisades Nuclear Power Plant to a newly-formed affiliate and to buy-back the output of the plant under a power purchase agreement (1990).

- Project manager responsible for a focused management audit of the fuel procurement practices of the Tucson Electric Power Company (1988).

- Project manager of a comprehensive competitive strategy study for a large investor owned electric utility. The study focused on opportunities for cost reductions, including bulk power transactions and power plant operations (1987).

- Project manager for an independent review of the financial plans of the Sacramento Municipal Utility District on behalf of its Board of Directors. The study included a review of power supply options (1987).

- Project manager responsible for the quantification for damages in Southwest Gas Corporation versus Tucson Electric Power Company. The damages study focused on quantifying the impact of the improper construction practices on the cost of a large gas distribution system (1986 - 1987).

- Project manager for a comprehensive construction prudence audit of The South Texas Nuclear Project, a 2,500 MW two unit nuclear generating station (1985).

- Project manager responsible for preparing all accounting evidence filed by the Mississippi Power & Light Company in a series of rate cases (1980 - 1985).

- Participated in a series of Fuel Adjustment Clause Compliance Audits of the Ohio Power Company, the Ohio Edison Company, Dayton Power & Light Company and Cincinnati Gas & Electric Company (1980 - 1984).

Work History

1991 - Present: **Overland Consulting**
Director of Energy Projects. Responsible for management and regulatory consulting projects, principally in the energy industry. Provides expert witness services in energy utility projects involving decision analysis, damages assessment, ratemaking and accounting.

1983 - 1991: **LMSL, Inc.**
Vice President. Responsible for energy utility regulatory projects involving decision analysis, damages assessment, ratemaking and accounting.

1979 - 1982: **Drees Dunn Lubow & Company**
Senior Regulatory Consultant. Participated in a variety of energy utility regulatory projects in the states of Arkansas, Indiana, Kansas, Louisiana, Mississippi, Missouri and Ohio.

1978 - 1979: **Arthur Andersen & Company**
Staff Accountant. Participated in financial statement audits of various companies, including electric utilities. Other responsibilities included preparation of exhibits for rate filings.

Qualifications

Education: Bachelor of Science degree in Business Administration, major in accounting, Central Missouri State University, 1978.

Professional Certifications: Kansas CPA certificate # 3326

Presentations: "Regulatory and Accounting Implications of Phase-in Plans", with Howard Lubow, NARUC *Biennial Regulatory Information Conference,* September 1984.