

**RESOLUTION**

**Resolution E-4003. Pacific Gas and Electric Company (PG&E) requests that its Reliability Performance Incentive Mechanism (RPIM) be made a part of its Distribution Revenue Adjustment Mechanism (DRAM) and that a penalty of \$2.8 million be adopted for its first year 2005 results. Approved.**

**By Advice Letter 2800-E dated March 9, 2006.**

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**SUMMARY**

**The Commission approves PG&E's Advice Letter 2800-E submitted to make its Reliability Performance Incentive Mechanism (RPIM) a part of its Distribution Revenue Adjustment Mechanism (DRAM), and to adopt for 2005, the first year for a reward or penalty, a RPIM penalty of \$2.8 million.** Next year PG&E is to apply the same methodology to its outage data when developing the RPIM reward or penalty results it files for in 2006, and shall file its internal audit of data that supports its RPIM filing.

**BACKGROUND**

**Electric utilities are required to report reliability indices to the Commission**

Decision (D) 96-09-045, effective September 4, 1996, requires electric utilities to maintain information adequate to calculate reliability indices by circuit, district, and division. Each electric utility is required to report reliability indices in an annual report to Energy Division by March 1 of the year following the calendar year reflected by the data used to calculate the indices. This Decision defines three system-wide reliability indices:

**System Average Interruption Duration Index (SAIDI)**

SAIDI is defined as the total minutes of sustained customer interruption divided by the total number of customers, expressed in minutes per customer per year.

**System Average Interruption Frequency Index (SAIFI)**

SAIFI is defined as the total number of sustained customer interruptions divided by the total number of customers, expressed in interruptions per customer per year.

**Momentary Average Interruption Frequency Index (MAIFI)**

MAIFI is defined as the total number of momentary customer interruptions divided by the total number of customers, expressed as momentary interruptions per customer per year.

The Commission defines a sustained outage as an outage that lasts 5 minutes or more; a momentary outage lasts less than 5 minutes.

D.96-09-045 allows electric utilities to exclude planned outages and excludable major events from reliability indices calculations.

Appendix A of D.96-09-045 defines an excludable major event as (a) an event that is caused by earthquake, fire, or storms of sufficient intensity to give rise to a state of emergency being declared by the government, or (b) any other disaster not in (a) that affects more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event.

**In 2004 the Commission Adopted a RPIM for PG&E**

In Application 02-11-017, PG&E's Test Year 2003 General Rate Case, an Assigned Commissioner's Ruling established a separate phase of the proceeding in order to evaluate PG&E's readiness for storms that occurred in December 2002 and PG&E's response to them. The Commission's Decision (D) 04-10-034 in the matter included Ordering Paragraph 8 that adopted a RPIM. Table 1 below shows the target metrics and incentive levels adopted in the decision. PG&E is rewarded for achieving outage duration and frequency levels below the lower limits of the deadbands, and is penalized for SAIDI and SAIFI values that rise above the deadbands.

<b>Table 1. PG&amp;E's Target Metrics and Incentive Levels for 2005</b>					
	<i>Liveband Lower Limit</i>	<i>Deadband Lower Limit</i>	<i>Target for 2005</i>	<i>Deadband Upper Limit</i>	<i>Liveband Upper Limit</i>
SAIDI excluding Major Events (minutes)	139.20	155	165	175	190.80
SAIFI excluding Major Events (Interruption/ Customer )	1.15	1.30	1.40	1.50	1.65
Max Annual Reward/Penalty	+ \$12 million	None	None	None	- \$12 million
SAIDI Per Unit Incentive	+ \$759,494 / minute change in SAIDI	None	None	None	- \$759,494 / minute change in SAIDI
SAIFI Per Unit Incentive	+ \$800,000 / 0.01 change in SAIFI	None	None	None	- \$800,000 / 0.01 change in SAIFI

**PG&E Hired EPRI Solutions to Correct Data to be Filed in its 2005 RPIM.**

In early 2005 a PG&E internal Quality Assurance (QA) review revealed errors in recorded reliability statistics that could affect its 2005 RPIM filing. By incorrectly classifying as

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momentary outages all outages less than 6 minutes PG&E would under-report the SAIDI index of sustained outages, which is part of the RPIM. D.96-09-045 defined the momentary outages that could be excluded from the SAIDI calculation to be limited to only 5 minutes duration. The MAIFI index would drop correspondingly but MAIFI is not a part of the RPIM.

PG&E reported to the Energy Division on June 21, 2005, that it had hired EPRI Solutions to analyze its January through April 2005 reliability data. PG&E met with Energy Division on October 20, 2005 to discuss the completed EPRI study which concluded that PG&E had under-recorded SAIDI by 2.0% and over-recorded SAIFI by 1.7% during this period, the first 4 months of 2005. In other words the average customer in PG&E's system was without service 1.3 minutes longer but had slightly less or 0.008 fewer interruptions.

Based on these results PG&E revised its on-going internal procedures and software to more correctly record outage data for the remainder of 2005 as it unfolded. Looking backward PG&E also revised reliability indices previously reported to the Commission starting with 1988 to adjust for the incorrectly classified momentary outages. The corrected data is reported as corrected in Section 1 of PG&E's March 1, 2006, annual electric distribution reliability report.

**PG&E filed Advice Letter 2800-E on March 9, 2006 proposing to revise its electric Preliminary Statement Part CZ – Distribution Revenue Adjustment Mechanism (DRAM) to incorporate the results of the RPIM each year and for 2005, to approve the \$2,810,128 penalty results of the RPIM.**

DRAM is a revenue adjustment mechanism in which PG&E's authorized distribution revenue requirement is compared to actual revenues recovered through the distribution component of rates. The balance in the DRAM is amortized annually in rates.

The reliability PBR rewards or penalties will adjust PG&E's authorized distribution revenue requirement such that the penalties or rewards are reflected in the balancing account amortization each year.

PG&E relied upon the EPRI-corrected SAIDI and SAIFI values as reported in its March 1, 2006 Reliability Annual Report to calculate rewards or penalties under the RPIM for 2005. PG&E classified electric outages that occurred in certain divisions on December 18, 19 and 20, 2005, and in the entire system on December 31, 2005 as Excludable Major Events. All or a majority of those divisions were declared to be in a state of emergency and thus were excluded from the final system SAIDI and SAIFI calculations.

PG&E reported 178.7 minutes/customer for SAIDI, which is 3.7 minutes/customer higher than the 175 minutes/customer limit of the deadband, resulting in the penalty of \$2,810,128.<sup>1</sup> The SAIFI value of 1.344, however, fell within the deadband of 1.3 to 1.5 interruptions per customer, and triggered no reward or penalty.

**NOTICE**

Notice of AL 2800-E was made by Publication in the Commission's Daily Calendar on March

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<sup>1</sup> 3.7 minutes x \$759,494/minute = \$2,810,128.

## **PROTESTS**

The Commission has received no protests.

## **DISCUSSION**

The high dollar values associated with unit values of SAIFI and SAIDI require careful review of PG&E's calculations, outage data processing, and reading of the applicable decisions.

### **The Commission Approves PG&E's Request to Make RPIM a Part of DRAM.**

As discussed in PG&E's AL and stated above, the balance in DRAM is amortized annually in distribution rates. RPIM is likewise designed for recovery through distribution rates. Accordingly, it is reasonable to include the results of RPIM in the DRAM mechanism.

### **PG&E Should Document All Corrections to Outage Data.**

On June 6, 2006, at staff's request PG&E provided data on customer-minutes<sup>2</sup> and customer-interruptions<sup>3</sup> associated with each outage event in 2005. Energy Division staff used this information to check reported SAIDI and SAIFI values and found a difference of 0.090 minutes/customer for SAIDI. This amounts to an increase of 485,219 customer minutes. On August 21, 2006, PG&E responded to further inquiry from Energy Division, reporting eleven modifications of outage data made between February 23, 2006, and March 27, 2006, regarding outage events on December 18 and December 31, 2005. However, since the events were categorized as major events they were excluded from the index calculations and had no effect on the final 2005 SAIDI value or the RPIM penalty value.

On September 12, 2006, PG&E stated there were actually nine modifications that took place between February 23, 2006 and March 27, 2006. Two of these modifications were inadvertent duplication due to query error. Only one of these nine outage modifications has an effect on SAIDI calculation. This was an outage that occurred on December 31, 2005, in the Peninsula Division, on the Woodside 1101 circuit, that resulted in a net reduction of 149,435 customer minutes of interruptions and 0.03 minute/customer in SAIDI.

PG&E later reported that two additional outages occurred in 2005 that were not entered into their database until after February 23, 2006. One of these outages occurred on December 31,

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<sup>2</sup> Customer minutes are defined as the product of the number of customers involved in a sustained outage and the duration of the sustained outage.

<sup>3</sup> Customer interruptions are defined as the product of the number of customers involved in a sustained outage and frequencies of that circuit interruption.

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2005, and had 488,124 customer minutes of interruptions (0.09 minutes/customer). Since this outage was part of an excludable event, it does not affect the final reliability indices calculations. However, the second outage with 7,650 customer minutes of interruptions (0.0014 minute/customer) that occurred on November 10, 2005, should have been included in the SAIDI calculation.

PG&E can not explain the remaining 138,880 customer minutes or 0.03 minute/customer of SAIDI (485,219 customer minutes - (-149435+7650+488124) customer minutes). PG&E stated that their OUTAGE program retains only the most recent modification. Therefore, the nine outages modified between February and June 2006 may have also modified their customer minute values. But since a query will return only the most recent change, older changes are “overwritten” by the most recent modification.

Appendix C summarizes the net effect of PG&E’s outage data modifications. The final system SAIDI including outage data modifications and 0.03 minute/customer of unexplained SAIDI is 178.73 minutes/customer.

### **PG&E Used Multiple Criteria, Some Subjective, to Define the Beginning and End of an Excludable Major Outage Event.**

#### Beginning and End of an Excludable Major Outage Event

D. 96-09-045 defines an excludable major event as a disaster that affects more than 15% of the system facilities or 10% of the utility’s customers. However, the Commission does not have a policy in place to define the beginning or end point of an excludable major outage event.

PG&E uses a 48-hour sliding window to identify when 10 percent of the Company’s customers have incurred a sustained outage. After identifying that an event has risen to the level of an excludable major outage, PG&E reviews the number of customer interruptions that occurred on the days before and after the event. The time-period of the major event is determined by including those consecutive days that exceed 30,000 sustained customer-interruptions per day. PG&E indicates that the 30,000 customer-interruptions value is based on its experience with major events, which are typically storm-related.

PG&E has been using this process to interpret the beginning or end of an excludable major outage event since 1996. The Commission adopted PG&E’s RPIM under this assumption. Hence, the Commission should continue allowing PG&E to use this method. But Energy Division recommends the Commission require PG&E to submit data to support the time spans of each year’s excludable major outage events in its annual RPIM advice letter filing.

#### Outage Exclusions due to a Proclamation of a State of Emergency

Appendix A of D.96-09-045 defines a state of emergency declared by the government as constituting an excludable major event, independent of the numbers of customers or interruptions. However, the Commission has no policy on excluding outages in a Division that includes some counties in a state of emergency along with others not having such a status.

The Governor issued three proclamations relating to the storms in mid-December 2005. The proclamations were made after the fact and dated January 2, January 3, and January 12, 2006.

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PG&E obtained copies of the Governor's proclamations that 34 counties, named in Appendix A, were in a state-of-emergency.

The proclamations refer to severe rainstorms that commenced on December 19, 2005. PG&E states the storms actually commenced on December 18, 2005. PG&E states that the number of outages, weather data, media coverage of the storm, and PG&E's twelve Operations Emergency Centers (OECs) that it activated before 2:00pm on December 18, 2005, all confirm the December 18 date.

PG&E then used the following process to determine whether to exclude outages in a given Division from the calculation of system reliability indices for the major event spanning December 18 through December 20, 2005. PG&E:

- Reviewed the affected county boundaries relative to its Division boundaries.
- Determined the percentage of the area of each division covered by the counties identified in the Governor's proclamations.
- Reviewed outage data from the affected divisions.
- Found that twelve of PG&E's divisions had more than fifty percent of their area covered by counties declared to be in a state of emergency: North Bay, North Coast, North Valley, Peninsula, Sacramento, Sierra, Stockton, Diablo, East Bay, Fresno, Los Padres and Mission (Appendix B).
- Selected a time span of December 17 through December 23, 2005 in order to determine the outage levels on the day before the storm began, and the outage levels following the storm. For most divisions, outage levels returned to "normal" on December 19 or December 20, 2005.
- The data reviewed included the numbers of sustained outages, customer interruptions, and customer minutes, as well as the corresponding data for the same December time periods in the years 2000-2004.
- Finally the comparison of outage data from the December 2005 storm to the previous five years of December outage data led PG&E to exclude outages beginning December 18, one day earlier than the Governor's earliest proclamation of December 19, for seven of its divisions: Diablo, East Bay, North Bay, North Coast, Peninsula, Sacramento and Stockton.
- In reviewing the daily outage data for December 19th and 20th, PG&E further concluded that it was reasonable to exclude outages for North Coast, Peninsula and the Sacramento divisions for December 19th, and the North Coast division for December 20th.

PG&E's method of excluding outages, while systematic, involves subjective judgments such as 50% of a county being declared in a state of emergency. Therefore, the Energy Division recommends the Commission direct PG&E to include in its annual RPIM filing all data considered in its decisions to include or exclude outages from its calculation of reward or penalty.

**The ability of PG&E to collect accurate and timely distribution outage data and maintain Quality Control and Quality Assurance Programs determine the accuracy of its calculation of reliability indices.**

PG&E defines the start of an outage event as the earliest time of "first no light" (FNL) or equipment operation/alarm. PG&E defines the end of an outage event when all restorable

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customers are returned to service, or at the time it is declared non-restorable by either a field person or operator.

Customers are considered “not restorable” when a:

- Customer requests PG&E to de-energize or not restore power when outage only affects that customer.
- Government agency requests PG&E to de-energize or not restore power.
- System-wide or localized natural disaster that prevents PG&E from accessing an area to safely restore power.

Of the many outages occurring in a normal week, PG&E indicates that its operating personnel at each electric control center perform a weekly data quality control review of at least three outages, corresponding to a review of approximately ten percent of all sustained outages.<sup>4</sup> Operating personnel correct errors as they are detected and communicate “lessons learned” as necessary with the other control center personnel.

PG&E points out that the sample size of 3 per week was not statistically determined, but rather based on judgment with consideration given to the other higher priority tasks operating personnel at each electric control center must perform round-the-clock.

PG&E states that it plans to implement in the next few months a similar random sample review process for mapping departments. PG&E mapping personnel are responsible for recording outages in the Company’s OUTAGE database. OUTAGE is the program mapping personnel uses to enter outage data they receive from control centers.

In addition to random sampling, PG&E extracts and compares data from the Company’s Integrated Logging Information System (ILIS) and the OUTAGE database. ILIS is the program that PG&E operating personnel use at control centers. By comparing data from these two sources, PG&E can identify potential errors in the following areas: a) outage start and end times; b) un-posted outages; c) duplicate outages; and in planned vs. unplanned outages (i.e., appropriately categorizing outages).

PG&E states that its operating and/or mapping personnel reviews and corrects potential errors after comparisons. Additionally, PG&E mapping personnel and distribution engineers review outages that exceed 100,000 customer-minutes to assure accurate outage reporting. PG&E indicates that, of total sustained outages, the percentage of sustained outages exceeding 100,000 customer outage minutes for the five year period from 2001-2005 excluding major events is 9.3%, and 10.7% with major events included. These values represent approximately 2,060 outages per year with major events excluded and approximately 2600 outages per year with major events included.

PG&E has implemented a variety of communication and training measures related to outage reporting accuracy over the last year, but has not yet compiled information to determine the results of the various steps the company is taking that relate to outage reporting accuracy.

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<sup>4</sup> (3 outages/week/control center) x (52 weeks) x (17 control centers) ≈ 2,600 outages reviewed annually at the electric control centers. There were approximately 24,000 sustained outages in 2005.

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However, PG&E is planning to perform an outage-reporting audit in the 4th quarter of 2006 and anticipates the results will provide a useful indication of outage reporting accuracy.

Energy Division staff recommends the Commission require PG&E to conduct an internal audit of its internal reporting of 2006 outage data and to submit the result of this audit with its RPIM Advice Letter filing in early 2007..

## **COMMENTS**

This is an uncontested matter in which the resolution grants the relief requested. Accordingly, pursuant to PU Code 311(g)(2), the otherwise applicable 30-day period for public review and comment was waived. On October 2, 2006 in response to the Draft Resolution, PG&E made the comments listed below. :

- The 2006 internal audit will reflect internal procedures improved by last year's audit and will not be as extensive as the 2005 audit.
- The audit will review a sample size of approximately 200 outages for an 85% confidence level, a sample size adequate to determine the effectiveness of the 2005 corrective actions and to give a reasonable indication of outage reporting accuracy for the 2006 data set.
- PG&E will not adjust 2006 SAIDI/SAIFI data if this internal audit indicates reasonably accurate data. If not, PG&E will investigate further.
- PG&E's internal audit of RPIM data should cover 2006 only. Energy Division can determine the need for an audit of 2007 outage data after receiving and evaluating PG&E's advice letter for the 2006 RPIM filing.
- The Draft required PG&E to retain records of all corrections to outage data, including the data before and after the change, the PG&E staff that initiated the changes, and the date and effects of the changes. The following reasons make that proposal impractical:
  - The year 2006 is virtually over;
  - A software solution to implement a new record-keeping requirement may cost over \$100,000, and cannot be ready by the beginning of 2007. Also, 2007 could be the last year for RPIM, and PG&E is considering a new outage reporting system after 2007.
  - Requiring mapping personnel to manually keep records of changes via hard-copy files is burdensome, since they process approximately 20,000 to 30,000 outages a year and approximately 10-15% of outage records are modified at least once. While not calculated, keeping hard copy files of all changes has a cost as well.

## **FINDINGS**

1. Decision (D) 96-09-045, effective September 4, 1996 requires electric utilities to maintain information adequate to calculate reliability indices by circuit, district, and division. Each electric utility is required to report reliability indices in an annual report to Energy Division.
2. System Average Interruption Duration Index SAIDI is defined as the total minutes of sustained customer interruption divided by the total number of customers, expressed in minutes per customer per year.
3. System Average Interruption Frequency Index SAIFI is defined as the total number of sustained customer interruptions divided by the total number of customers, expressed in

interruptions per customer per year.

4. D.96-09-045 allows electric utilities to exclude planned outages and excludable major events from reliability indices calculations.

5. The Government's Proclamation of a State of Emergency for a day justifies excluding associated outages from the reliability indices.

6. The Commission has no policy on interpreting the beginning or end of an excludable major outage event, or how to treat outages in a Division that includes some counties in a state of emergency and others that are not.

7. Ordering Paragraph 8. of Decision 04-10-034 adopted a Reliability Performance Incentive Mechanism under which PG&E is rewarded for achieving outage duration and frequency levels (SAIDI and SAIFI values) below the lower limits of the deadbands, and is penalized for SAIDI and SAIFI values that rise above the deadbands.

8. PG&E discovered a systematic data error in its early 2005 reliability data relating to the classification of monetary and sustained outages. It eliminated the source of error. Additionally, PG&E contracted with EPRI Solutions to better understand the accuracy of its January thru April 2005 reliability data.

9. The EPRI study quantified under-reporting of SAIDI values and over-reporting of SAIFI values during this period. PG&E filed adjusted reliability data for all previously reported SAIDI and SAIFI values, in its March 1, 2006, annual electric distribution reliability report.

10. PG&E in this Advice Letter requests authority to revise Preliminary Statement Part CZ to incorporate the RPIM in its DRAM and to book a \$2,810,128 penalty for its 2005 RPIM results based on corrected outage data.

11. During Energy Division analysis PG&E reported nine modifications of outage data PG&E made between February 23, 2006, and March 27, 2006 regarding outage events on December 18 and December 31, 2005. The 2 days were categorized as major events and therefore excluded from the index calculations and had no effect on the final 2005 SAIDI value or the RPIM penalty value.

12. PG&E indicates that its operating personnel at each electric control center perform a weekly review of at least three outages or approximately ten percent of all sustained outages.

13. PG&E mapping personnel and distribution engineers regularly review outages that exceed 100,000 customer-minutes in order to improve outage-reporting accuracy.

14. PG&E plans to perform an outage-reporting audit in the 4th quarter of 2006.

15. It is reasonable to include RPIM in DRAM.

16. Energy Division recommends the Commission require PG&E to submit the following information with its future RPIM filings:

- Results of the outage reporting internal audit for 2006.

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- Data to support the time spans of each year's excludable major outage event.
- Data to support outage exclusions during each declared state of emergency.

**THEREFORE, IT IS ORDERED THAT:**

1. PG&E's Advice Letter 2800-E is approved in order to incorporate PG&E's Reliability Performance Incentive Mechanism (RPIM) as part of its Distribution Revenue Adjustment Mechanism (DRAM), and to adopt for 2005 a RPIM penalty of \$2,810,128.
2. The 2006 PG&E RPIM advice letters shall include:
  - a) Data supporting the start and end time of each excludable major event;
  - b) Data supporting each event excluded due to a declared state of emergency; and
  - c) The results of an audit of the outage data used to supports any filing it makes for a reward or penalty under RPIM. Internal audit result accuracies should be in the 85% confidence level.
  - d) All data bearing on exclusion of outages from RPIM results.
3. This Resolution is effective today.

I hereby certify that the Public Utilities Commission adopted this Resolution at its regular meeting on October 19, 2006. The following Commissioners voting favorably thereon:

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STEVE LARSON  
Executive Director

MICHAEL R. PEEVEY  
PRESIDENT  
GEOFFREY F. BROWN  
JOHN A. BOHN  
RACHELLE B. CHONG  
Commissioners

Commissioner Dian M. Grueneich, being necessarily absent, did not participate.

**Appendix A**

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PG&E submitted the following data to the Energy Division on 6/9/2006:

**Counties named in the Governor's proclamations of State of Emergency**

January 2, 2006 Proclamation – Del Norte, Humboldt, Mendocino, Napa, Sacramento, Sonoma, and Trinity

January 3, 2006 Proclamation – Butte, El Dorado, Lake, Lassen, Marin, Nevada, Placer, Plumas, San Joaquin, San Mateo, Sierra, Siskiyou, Solano, Sutter, Yolo, and Yuba

January 12, 2006 Proclamation – Alameda, Alpine, Amador, Colusa, Contra Coast, Fresno, Kings, San Luis Obispo, Santa Cruz, Shasta, and Tulare

**Appendix B**

PG&E submitted the following data to the Energy Division on 6/9/2006:

**Relationship between PG&E Division Boundaries and County Boundaries for the  
 December 18-20 Storm Event**

<i>PG&amp;E Division</i>	<i>Percent of Area of Division Comprised of Counties Declared to be in a State of Emergency</i>	<i>Dates that Division Outage Data was Excluded from System Outage Data</i>
North Coast	100%	December 18, 19, 20
North Bay	100%	December 18
East Bay	100%	December 18
Diablo	100%	December 18
Sierra	100%	No exclusions
Mission	100%	No exclusions
Fresno	99%	No exclusions
Peninsula	98%	December 18, 19
Sacramento	98%	December 18, 19
Stockton	68%	December 18
North Valley	65%	No exclusions
Los Padres	54%	No exclusions
Kern	13%	No exclusions
Central Coast	9%	No exclusions
De Anza	8%	No exclusions
Yosemite	7%	No exclusions
San Francisco	2%	No exclusions
San Jose	0%	No exclusions

**Appendix C**

<b>Net Effect on System SAIDI from PG&amp;E's Outage Data Modifications</b>						
<b>Line #</b>	<b>Description</b>	<b>Division or System</b>	<b>Date</b>	<b>SAIDI</b>	<b>SAIFI</b>	<b>Comment</b>

1	<b>Step 1: January to April adjustment associated with EPRI Solutions' Report</b>					
2	Starting point: January - April	SYSTEM	Jan - Apr 2005	65	0.449	
3	Adjustment Factors (+2.0% for SAIDI and -1.7% for SAIFI, from EPRI report)			0.02	-0.017	
4	Resulting adjustment (line 2 multiplied by line 3)			1.3	-0.008	
5						
6	<b>Step 2: Annual adjustment from EPRI Solutions' Report</b>					
7	Starting point: January - December data	SYSTEM		236.815	1.487	Staff Calculated system SAIDI based on data submitted by PG&E on 6/9/2006
8	Adjustment values (from line 4)			1.3	-0.008	
9	Subtotal 1 (line 7 plus line 8)			238.12	1.479	
10	<b>Step 2A: Adjust for outage record modifications submitted by PG&amp;E on 9/13/06</b>					
10a		PENINSULA	31-Dec	-0.03		Reduce 149,435 customer minutes
10b		NORTH COAST	10-Nov	0.0014		7,650 customer minutes
10c		NORTH COAST	31-Dec	0.09		488,124 customer minutes
10d	Subtotal 2 (Sum of line 10a, 10b, and 10c)			0.064		
10e	Subtotal 3 (line 9+10d)			238.179		
11	<b>Step 3: Subtract excluded days</b>					
12	Starting point: Excludable December data	DIABLO	18-Dec	0.38	0.003	
13		EAST BAY	18-Dec	0.48	0.003	
14		NORTH BAY	18-Dec	0.38	0.002	
15		NORTH COAST	18-Dec	0.75	0.003	
16		PENINSULA	18-Dec	1.03	0.004	
17		SACRAMENTO	18-Dec	0.39	0.002	
18		STOCKTON	18-Dec	0.18	0.001	
19		NORTH COAST	19-Dec	0.27	0.001	
20		PENINSULA	19-Dec	0.06	0.001	
21		SACRAMENTO	19-Dec	0.08	0.000	
22		NORTH COAST	20-Dec	1.11	0.003	
23		SYSTEM	30-Dec	2.23	0.009	
24		SYSTEM	31-Dec	51.98	0.103	
24a		PENINSULA	31-Dec	-0.03		Reduce 149,435 customer minutes
24b		NORTH COAST	31-Dec	0.09		488,124 customer minutes
25	Subtotal (Sum of lines 12 thru 24b)			59.38	0.135	
26						
27	<b>Step 4: Calculate final value</b>					
28	2005 SAIDI & SAIFI excluding major events and adjusted for EPRI Solutions Report (line 9 minus line 25)			178.73	1.344	