STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

October 14, 2004

Agenda ID# 3971
(Alternate to Agenda ID #3431)
Ratesetting

TO: PARTIES OF RECORD IN APPLICATION 02-11-017, et al.

RE: ALTERNATE PROPOSED DECISION OF COMMISSIONER SUSAN KENNEDY
(Mailed 10/14/2004)

Consistent with Rule 2.3(b) of the Commission's Rules of Practice and Procedure, I am issuing this Notice of Availability of the above-referenced alternate proposed decision. The proposed decision was issued by Administrative Law Judge (ALJ) Halligan on April 6, 2004. An Internet link to these documents was sent via e-mail to all the parties on the service list who provided an e-mail address to the Commission. An electronic copy of this document can be viewed and downloaded at the Commission's Website (www.cpuc.ca.gov). A hard copy of this document can be obtained by contacting the Commission's Central Files Office [(415) 703-2045].

Any recipient of this Notice of Availability who is not receiving service by electronic mail in this proceeding or who is unable to access the link to the Commission's web site given above may request a paper copy of the above documents from the Commission's Central Files Office, at (415) 703-2045; e-mail cen@cpuc.ca.gov.

When the Commission acts on the proposed decision or alternate proposed decision, it may adopt all or part of them as written, amend or modify them, or set them aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

As set forth in Rule 77.6, parties to the proceeding may file comments on the alternate at least seven days before the Commissioner meeting or no later than October 21, 2004. Reply comments should be served by noon on October 26, 2004. An original and four copies of the comments and reply comments with a certificate of service shall be filed with the Commission's Docket Office and copies shall be served on all parties on the same day of filing. The Commissioners and ALJ shall be served separately by overnight service. These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages.

Consistent with the service procedures in this proceeding, parties should send comments in electronic form to those appearances and the state service list that provided an electronic mail address to the Commission, including ALJ Julie Halligan at jmh@cpuc.ca.gov. Service by U.S. mail is optional, except that hard copies should be served separately on Brian Prusnek, Advisor to Commissioner Kennedy (bcp@cpuc.ca.gov). For that purpose I suggest hand delivery, overnight mail or other expeditious methods of service. In addition, if there is no electronic address available, the electronic mail is returned to the sender, or the recipient informs the sender of an inability to open the document, the sender shall immediately arrange for alternate service (regular U.S. mail shall be the default, unless another means – such as overnight delivery is mutually agreed upon). The current service list for this proceeding is available on the Commission's Web page, www.cpuc.ca.gov.

/s/ Angela K. Minkin
Chief Administrative Law Judge

ANG:cvm

Decision: ALTERNATE PROPOSED DECISION OF COMMISSIONER KENNEDY (Mailed 10/14/2004)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Revenue Requirements for Electric and Gas Service and to Increase Rates and Charges for Gas Service Effective on January 1, 2003.	Application 02-11-017 (Filed November 8, 2002)
Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Pacific Gas and Electric Company.	Investigation 03-01-012 (Filed January 16, 2003)
Application of Pacific Gas and Electric Company Pursuant to Resolution E-3770 for Reimbursement of Costs Associated with Delay in Implementation of Pacific Gas and Electric Company's New Customer Information System Caused by the 2002 20/20 Customer Rebate Program.	Application 02-09-005 (Filed September 6, 2002)

INTERIM OPINION ON STORM AND RELIABILITY ISSUES

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1. Summary

This interim decision addresses Storm and Reliability issues raised in PG&E's General Rate Case (GRC) for test year (TY) 2003. Today's decision evaluates PG&E's response to the December 2002 storms and PG&E's reliability performance in general. We approve several "improvement initiatives" identified by PG&E in response to problems with the Outage Information System (OIS) and Customer Information Systems that arose during the December 2002 storms. We find that PG&E's recommended initiatives are likely to improve outage communication and reduce outage duration and should be approved. We approve a change in the call center measurement standard requested by PG&E.

Today's decision also considers joint testimony submitted by PG&E and the Office of Ratepayer Advocates (ORA) addressing the issues raised by ORA's testimony. With regard to the PG&E/ORA joint proposal, we concur with six of the Agreements, modify two of the Agreements, and reject one of the Agreements. We do not adopt Agreement 6 of the PG&E/ORA joint proposal. As discussed in this decision, we believe that the existing value of service data is too dated to rely on, and that little would be gained by further "assessment" of this data. In lieu of the value of service assessment proposed in Agreement 6, we direct PG&E to conduct a new value of service study prior to its next GRC. This decision approves Agreement 7 with modifications.

The decision also addresses the reliability performance incentive mechanism presented in joint testimony filed by PG&E and the Coalition of California Utility Employees (CUE). We adopt the PG&E/CUE performance incentive mechanism with modifications. We find that the PG&E/CUE performance incentive mechanism as proposed is not in the public interest

because the performance targets fail to appropriately account for existing funding commitments and commensurate reliability improvements, and the mechanism would result in an unjustified increase in PG&E's revenue requirement. However, we find that a more narrowly refined performance incentive mechanism than proposed by PG&E/CUE has value in encouraging improvements in system reliability.

Today's decision does not find that PG&E's response to December 2002 storms was reasonable. Our review of PG&E's response to the December 2002 storms finds that while the multiple outages and severe damage caused by the storm were not the result of PG&E's performance, the inadequacy of PG&E's OIS resulted in several unacceptable consequences, including customers being unable to receive accurate outage information in a timely manner, certain single customer outages being extended for an unnecessary amount of time, and emergency personnel being required to stand by hazardous conditions for excessive periods of time during the storms.

2. Procedural Background

In response to customer concerns regarding PG&E's storm performance and system reliability following a series of storms occurring in December 2002, the Assigned Commissioner in Application (A.) 02-11-017, PG&E's TY 2003 GRC application issued an Assigned Commissioner's Ruling (ACR) seeking supplemental testimony concerning PG&E's electric distribution service during both normal and storm conditions and establishing a separate phase of the GRC proceeding to evaluate PG&E's response to the storms and its readiness for them.

In establishing a separate storm and reliability phase, the ACR explained that this phase of the proceeding was "not designed to focus only on PG&E's performance in the December 2002 storms or in individual circuits, but rather to allow us to gain a fuller understanding of the resources PG&E invests in reliability, maintenance, and emergency response efforts and how resources are prioritized in order to allow us to provide additional direction, through the creation of relevant standards or metrics, by which its performance should be judged."[1] Appendix A to the ACR provided a list of topics to be addressed in this phase of the proceeding. The ruling also scheduled hearings on the storm and reliability issues.

PG&E filed supplemental testimony on these matters on March 17, 2003. On May 2, 2003, storm and reliability testimony was submitted by ORA, CUE, and The Utility Reform Network (TURN). In order to assist in their review of PG&E's supplemental testimony, ORA retained the services of Stone and Webster Management Consultants. ORA's testimony submitted on May 2, 2003 consisted of two volumes of testimony, including a review of PG&E's supplemental testimony by Stone and Webster. In addition, on May 9, 2003, Stone and Webster submitted a third volume of testimony, consisting of its final report on the reliability performance of PG&E at the division level.

The Commission held five days of evidentiary hearings on the storm and reliability issues from May 28 to June 4, 2003. PG&E, ORA, CUE, TURN and Aglet Consumer Alliance (Aglet) participated during the hearings by presenting testimony, cross-examining witnesses, or both. On July 10, 2003, several weeks after the hearings on the storm and reliability issues, PG&E and CUE filed jointly sponsored testimony addressing issues raised by CUE's testimony. PG&E and ORA also filed jointly-sponsored testimony that represented a compromise they had reached on the issues raised by ORA's testimony and the Stone and Webster

[1] Scoping Memo Feb. 13, 2003, p.5.

reports. Also on July 10, 2003, TURN filed a response to both sets of jointly sponsored testimony. An additional day of hearing on the joint testimony and TURN's response was held on July 14, 2003.

Opening Briefs on the Storm and Reliability issues were timely filed by PG&E, ORA, CUE, TURN, and Aglet on July 21, 2003. Reply briefs were filed by PG&E, ORA, CUE, TURN, and Aglet on August 11, 2003. The Storm Response and Reliability Phase of the GRC was submitted upon receipt of reply briefs.

3. Commission Standards for Evaluating Utility Performance

Under current statutes, PG&E enjoys an effective monopoly in the provision of electric and gas distribution service. (C.f., Pub. Util. Code §§ 330(f)(electric) and 328 and 328.2(gas).) In order to prevent abuse of this monopoly, the Legislature has given the Commission broad powers of regulation and investigation. The Commission exercises those powers to assure the public that the prices they pay for electric and gas distribution service are in fact just and reasonable, and reasonably related to costs prudently incurred by efficient, conscientious managers to provide the quality of service we expect. The quality we expect is described in Pub. Util. Code § 364, which requires the Commission to adopt standards for utility distribution systems that provide for high quality, safe, and reliable service. As we stated in Decision (D.) 00-02-046, we intend to hold PG&E to this high standard of service quality, and we expect prudent and effective management of the financial resources we have placed under its control.[2]

Under the Public Utilities Act, our primary purpose is "to insure the public adequate service at reasonable rates without discrimination…" (*Pacific Telephone*

[2] D.00-02-046, p. 27.

and Telegraph Company v. Public Utilities Commission (1950) 34 Cal.2d 822,826 [215 P.2d 441]; *Pacific Telephone and Telegraph Company v. Public Utilities Commission* (1965) 62 Cal.2d 634,647 [44 Cal. Rptr. 1, 401 P.2d 353]; *City and County of San Francisco v. Public Utilities Commission* (1971) 6 Cal. 3d 119, 126 [98 Cal. Rptr. 286, 490 P.2d 798].) We referred to the high quality of service we expect as "adequate," finding that "adequate service connotes a well-managed and sophisticated firm *continuously meeting and exceeding* public demand for the firm's output." We also held that "[a] utility which provides adequate service is in compliance with laws, regulations, and public policies that govern public utility facilities and operations." We stated that: "adequate service encompasses all aspects of the utility's service offering, including but not limited to safety, reliability, emergency response, public information services, and customer service," and emphasized that: "adequate service is not pejorative term, and in no way does our use of it imply acceptance of mediocrity in the utility's service offering."[3]

Furthermore, Pub. Util. Code § 451 requires public utilities to provide "adequate, efficient, just, and reasonable service" in a way that promotes the "safety, health, comfort, and convenience of [their] patrons, employees and the public," but also holds that all charges demanded or received by any public utility for these services shall be just and reasonable. Under §§ 701 and 728, the Commission has the authority to determine what is just and reasonable, and to disallow costs not found to be just and reasonable.

Through several decisions, rules, and general orders, we have provided the utilities with guidance regarding what constitutes a reasonable level of

[3] D.00-02-046, p. 31.

service. During the 1995-1996 storm season, heavy storms throughout PG&E's service territory caused thousands of PG&E customers to experience unusually long electric service outages. In response to those events, we initiated investigations and proceedings to determine improvements that could be made to reduce the future potential for customers experiencing such outages and to develop uniform benchmarks for measuring the utilities' performance during normal operations as well as their performance in restoring service following abnormal events.

In general, the investigations and proceedings resulted in three decisions which sought to assure that all jurisdictional electric utilities: 1) routinely provide the Commission with uniform data regarding their overall service reliability (D.96-09-045); 2) conform to prescribed standards regarding emergency preparedness and coordination (D.98-07-097); and 3) have a mandated benchmark against which the reasonableness of their performance during major outages could be measured (D.00-05-022). In all three decisions, we took great care to assure that the requirements applied uniformly to all utilities affected by the decisions.

In addition to the standards described below, all electric utilities are also subject to Rule 35 of GO 95, which requires utilities to maintain specified clearance between overhead primary lines and vegetation at all times, and GO 165, which sets forth inspection cycle standards and reporting requirements.

3.1 D.96-09-045 – Reliability Standard and Reporting

D.96-09-045 adopted recording and reporting requirements designed to provide uniform methods for assessing data related to the frequency and duration of system outages, circuits that persistently perform poorly, and accidents or incidents affecting reliability. We directed the utilities to record and report system reliability information annually using the following indices:

a. **System Average Interruption Frequency Index (SAIFI).** A.02-12-027, et al. SAIFI measures the average number of sustained power interruptions[4] for each customer during a specified time period. It is calculated by dividing the total number of sustained customer interruptions by the total number of customers.

b. **System Average Interruption Duration Index (SAIDI).** SAIDI measures the average duration of outages per customer. It is calculated by dividing the total minutes of sustained customer interruptions by the total number of customers.

c. **Momentary Average Interruption Frequency Index (MAIFI).** MAIFI measures the average number of momentary outages per customer. MAIFI is calculated by dividing the total number of momentary interruptions by the total number of customers.

The measures above are typically calculated for a one-year period and may be calculated at the system level or at subsystem levels, such as the area or division level. We did not adopt specific performance targets, but held that "a minimum level of reliability for statutory purposes is the level that has historically been found reasonable, as measured by indices in use at the time by each utility."[5] We also held that, "although system measures of reliability may give us the means for holding utilities accountable to measurable criteria,

[4] A sustained interruption is an outage that lasts at least five minutes; a momentary interruption is an outage that lasts less than five minutes.

[5] D.96-09-045, Findings Of Fact 15

satisfaction of system measures (meeting historically reasonable levels) is not a shield that can stave off liability for damages in other forums or individual customer complaints in this forum."[6] We also found that "system measures may mask more localized problems, and the utility may still be found to have acted unreasonably with respect to maintenance or replacement of some portion of the system."[7] To address this concern, we directed the utilities to record the reliability indices using a portion of the system (circuit, division, region, or district), or smaller time periods, and provide this information to any interested person upon request. Since system design and recording capability differs among the utilities, we directed the utilities to record information at whichever of these levels their then current information collecting capacities existed.

We also required the utilities to include in the annual reports the number of poorly performing circuits, defined as those in which at least one customer experiences more than 12 outages in any 12-month period. This measure was intended to identify circuits that require evaluation and create an incentive to reduce poor circuit performance.

In order to avoid skewing the data with infrequent and unusual events, we allowed the utilities to exclude certain "Excludable Major Events" defined as events caused by earthquake, fire, or storms of sufficient intensity which result in a state of emergency being declared by the government. Absent the declaration of a state of emergency, any other natural disaster may be excluded only if it affects more than 15% of the system facilities or 10% of the customers, whichever is less for each event.

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[6] D.96-09-045, pg. 12

[7] *Id.*

3.2 D. 98-07-097 - GO 166

In D.98-07-097, the Commission established GO 166, which set forth eleven standards relating to electric service reliability and / or safety. The purpose of GO 166 is to ensure that jurisdictional electric utilities are prepared for emergencies and disasters in order to minimize damage and inconvenience to the public that may occur as a result of electric system failures, major outages, or hazards posed by damage to electric distribution facilities. GO 166 contains detailed requirements for emergency planning as well as performance during emergencies. The standards are intended to facilitate our investigations into the reasonableness of the utility's response to emergencies and major outages. GO 166 defines "Major Outage" as an event when 10% of the electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service. GO 166 requires that an investigation be conducted following every major outage.

3.3 D. 00-05-022 – GO 166: Standards 12 and 13

D.00-05-022 added Standards 12 and 13 to GO 166 and defined "Measured Event." Standard 12 sets a restoration time performance benchmark for major utilities. The benchmark is a Customer Average Interruption Duration Index (CAIDI) value of 570 minutes. CAIDI, which is calculated by dividing the total number of customer minutes of interruption by the total number of customer interruptions, measures the average duration of the outages experienced by customers. Under Standard 12, a utility's restoration performance would be considered unreasonable if it exceeded 570 minutes. Standard 13 requires utilities to meet a call center performance benchmark measured by the percent of customer calls receiving a busy signal during a Measured Event, a "percent busies" standard. Under Standard 13, the percent busies is presumed reasonable if it is 30 percent or less over a 24-hour period, and presumed unreasonable if it is

50 percent over the day, plus 5 percent in each of six one-hour segments. A Measured Event is defined as a Major Outage resulting from non-earthquake, weather-related causes, affecting between 10% (simultaneous) and 40% (cumulative) of a utility's electric customer base.

3.4 PG&E Specific Standards

While the standards adopted in the three decisions discussed above apply to all jurisdictional utilities, three other decisions adopted standards that apply specifically to PG&E. In response to PG&E's performance during the January and March 1995 storms, D.95-09-073 required PG&E to implement specific improvements to its call center operations and emergency preparedness. We adopted an Average Speed of Answer (ASA) standard, which requires PG&E to achieve an average wait of less than 20 seconds to speak with a call center representative. We also adopted a "percent busies" standard that requires PG&E to maintain a busy signal occurrence of less than 1% during normal operations and less than 3% during outages.[8] In D.96-11-014, the Commission explained that compliance with the percent busies requirement is calculated on a calendar month basis, excluding days affected by abnormal circumstances. We also directed PG&E to make several other improvements to its call center operations and emergency preparedness.

Seven quality assurance standards for residential ratepayer customer service were adopted in D.00-02-046, addressing: 1) missed appointments; 2)

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[8] As discussed in Section 7.3 of this decision, the performance standards in GO 166 apply during Major Outages, which are events resulting in power interruptions to 10 percent of a utility's customers simultaneously. GO 166 also states that Standard 13 regarding call center performance during Major Outages applies only during "Measured Events."

non-emergency service investigations and repairs; 3) emergency service investigations and repairs; 4) complaint resolution; 5) new installations; 6) response to service disruptions; and 7) restoring service. The standards were accompanied by credits to customers if the standards are not met. These standards do not apply during significant emergencies, such as the December 2002 storms. PG&E reports that since their inception in the year 2000 through 2002, it provided customer credits totaling approximately $1.6 million.

D.03-02-041, which resulted from a Commission investigation into the power outage that occurred within PG&E's system on December 8, 1998, requires PG&E to provide the Commission's Energy Division and Consumer Protection and Safety Division with quarterly reports detailing statistics related to SAIDI and SAIFI values, Maintenance Repair and Replace Outages (MR&RO), along with root cause reports, specifying actions being taken and work completed related to distribution outages, for San Francisco and system-wide. In addition, PG&E is required to keep OSHA reporting information available upon request. After three years from the effective date of this decision, PG&E is allowed to request termination of the reporting requirements adopted therein.

4. PG&E's Existing System

In response to Appendix A of the ACR, PG&E provided testimony on system design, staffing, call center performance, deployment of resources, outage commissions, and reliability performance in general and during the December 2002 storms. PG&E's electric distribution system serves 4.7 million customers throughout Northern California, from Eureka in the north, to Bakersfield in the south, and extending from the Sierra Nevada Mountains in the east, to the Pacific Coast in the west. Approximately 50% of PG&E's customers reside in the San Francisco Bay Area. PG&E maintains 2.3 million poles, 93,000 miles of overhead circuits, 22,000 miles of underground circuits, 300,000 underground enclosures, and 2,500 distribution substation transformers. PG&E trims or removes approximately 1.8 million trees annually to ensure clearance between vegetation and overhead lines and maintain compliance with all rules and regulations.

Electricity consumed by PG&E's customers is delivered to PG&E's distribution system via high-voltage transmission lines. PG&E has almost 800 substations that connect PG&E's distribution system to the high-voltage transmission system. These substations are the central hubs of PG&E's distribution system. Each substation transforms the high-voltage electricity (e.g., 230 kilovolt (kV)) to a lower voltage electricity (e.g., 12 kV) for delivery to end-use customers. Primary and secondary distribution lines extend from each substation and deliver electricity overhead or underground. Local transformers that further lower the voltage level (e.g., 12 kV to 240 volts (V)) and switching equipment link the distribution lines in patterns that provide service drops to meters at customer premises.

PG&E's service territory is divided into 7 operating areas, 18 operating divisions, and 3,033 individual circuits. Service reliability and staffing varies by area and division due to circuit design, geography, customer density and other factors. Table 1, below, contains the 2002 Division and system values for the number of customers served, the number of circuits, the line miles of primary overhead and underground distribution circuitry, and the SAIDI and SAIFI performance indices.

TABLE 1
PG&E 2002 SERVICE RELIABILITY METRICS BY DIVISION

Division	Customers	Circuits	OH Miles	UG Miles	Total Miles	Excluding Major Events SAIDI	Excluding Major Events SAIFI	Including Major Events SAIDI	Including Major Events SAIFI
Central Coast	290,610	163	5,839	1,125	6,965	206.6	1.390	605.2	2.273
DeAnza	216,340	121	1,741	828	2,569	101.7	0.838	387.5	1.418
Diablo	292,653	128	2,239	2,093	4,333	124.1	1.372	203.4	1.729
East Bay	356,741	206	1,765	875	2,641	111.7	0.980	189.3	1.451
Fresno	380,985	285	10,867	2,064	12,932	161.0	1.323	218.2	1.518
Kern	216,083	228	7,035	1,162	8,197	151.3	1.201	184.9	1.335
Los Padres	187,360	76	4,578	876	5,454	121.0	1.177	162.4	1.490
Mission	361,329	156	1,823	2,326	4,150	65.5	0.823	99.0	1.084
North Bay	245,682	96	2,805	1,173	3,979	138.2	1.212	747.5	2.521
North Coast	362,934	186	10,455	1,587	12,043	223.1	1.178	1,098.1	2.330
North Valley	199,093	155	10,055	815	10,871	231.2	1.416	977.6	2.458
Peninsula	301,086	201	2,250	1,062	3,313	99.0	0.978	457.2	1.778
Sacramento	192,811	121	4,899	1,262	6,161	165.2	1.274	280.0	1.711
San Francisco	398,882	254	573	620	1,193	69.8	0.624	127.8	0.921
San Jose	380,913	155	2,360	2,156	4,516	108.4	0.931	193.6	1.219
Sierra	248,784	149	7,896	1,346	9,242	176.6	1.200	612.2	2.174
Stockton	262,745	191	6,215	1,427	7,642	181.2	1.314	326.3	1.879
Yosemite	225,733	162	10,958	866	11,824	137.5	1.245	215.1	1.497
System	5,120,764	3,033	94,361	23,671	118,033	139.2	1.112	381.9	1.670

As of December 31, 2002, PG&E employed a total of 3245 electric field personnel, a reduction of 14% from the 3699 field personnel PG&E employed as of 1998. All electric field personnel are available for emergency response. PG&E does not have separate staff dedicated to “reliability,” “maintenance,” or emergency response functions. Rather, individuals in these job categories perform work in a variety of functions and may be installing facilities to connect new customers one day and restoring power during an outage the next day.

As discussed above, the metrics the Commission considers when examining PG&E’s electric reliability include SAIFI, SAIDI, CAIDI, MAIFI, the number of circuits that consistently perform poorly, and the MR&ROs per line mile. During emergencies and severe storms, PG&E's performance is also measured against a service restoration performance metric.

In addition to these metrics, PG&E internally evaluates its performance using metrics related to employee safety, customer service, and call center performance. MR&RO, defined as the total number of unplanned sustained outages that could be influenced by inspection and maintenance activities, was developed to measure the effectiveness of PG&E's inspection and maintenance practices. PG&E's average performance from 1999 through 2001 for the MR&RO and the number of circuits with greater than 12 outages per year improved relative to 1996 through 1998 performance for MR&RO or 1997-1998 performance for the number of circuits with greater than 12 outages per year.

Prior to 2002, PG&E tracked Occupational Safety and Health Administration (OSHA)-recordable events to measure employee safety performance. However, PG&E is re-evaluating whether the OSHA recordables metric remains appropriate since OSHA changed its reporting rules and definitions effective January 1, 2002. PG&E's OSHA recordables performance from 1999-2001 improved relative to PG&E's performance from 1996-1998. For 2002, PG&E used three measures of lost work days: (1) lost work days per case; (2) lost work days; and (3) lost work days per employee.

PG&E also tracks customer service quality through customer surveys and by measuring the effectiveness of outage management functions, such as providing information about an outage and providing accurate information on how long an outage will last.

PG&E has a network of three call centers that provide customer service through a combination of service representatives and Voice Response Unit (VRU) systems at all times. The VRU automated self-service functions include a general service / information menu for account balances, payment arrangements, and appliance service appointments. There is also a VRU menu for outages, which includes options to hear outage status messages, to report outages, and to request a callback. The call centers have over 900 inbound telephone lines for customers, with a capacity of handling over 500,000 calls per hour. In a normal week, the call center representatives and automated response systems handle about 260,000 calls.

PG&E uses a computerized OIS to identify, track, and communicate information for electric outages. PG&E uses its OIS in two key ways: (1) to assist in deploying resources to address outages, and (2) to provide outage information to customers via the call center. PG&E's OIS links field information (e.g., outage location, causes, response assignments, and estimates of restoration) to PG&E's Customer Information System (CIS), which is used in the call centers to communicate with customers. The OIS receives outage information from several sources, including customer calls, automatic system devices located on PG&E's facilities, field personnel, and Enhanced Outage Notification devices located in customer homes. The OIS addresses outages affecting multiple customers, such as during storm events. For single customer outages, trouble reports are managed through the Field Automation System.

When an outage report is entered into the OIS system, the system notifies the appropriate dispatcher. The dispatcher then sends a troubleman to the outage location and initiates an outage record in OIS, with an estimated time of arrival. Once this information is recorded in the OIS it becomes accessible to customers through the call center.

When an outage call is received, the call center systems check the OIS for outage record and status information. If there is no record of an outage, the customer is advised of this and can report the outage. If there is a record of an outage, the call centers provide the customer with the available outage status information including the estimated time of restoration (ETOR).

PG&E tracks the ETORs provided to the call centers for each of its outages so that it can compare the ETOR times in its OIS with the actual time the power was restored. PG&E does not record the ETOR information provided to customers when they call and therefore cannot compare the ETORs received by the customers to the actual time of restoration. PG&E states that the comparison of the first ETOR to actual restoration time provides a measure of how well PG&E's field and dispatch personnel estimate the time it takes to restore service, and comparing the last ETOR to actual restoration time measures how well the ETOR improves over time as better information becomes available.

PG&E's OIS database contains information concerning outages recorded since January 1, 2000. Comparable data from PG&E's prior outage database, CTAS, was not archived, and is not available. For the past three years, from 2000 through 2002, PG&E's ETOR was, on average, within two hours of the actual time of restoration. During non-major event conditions, including storms, PG&E either provided an ETOR, or restored service within four hours to 85 percent of all outages. In other words, customers who called PG&E to find out the ETOR of their service were provided an ETOR that, on average, was within four hours of the actual restoration time.

There were three major events in PG&E's service territory from 2000 through 2002. During these major events, PG&E either provided an ETOR, or restored service within four hours to an average of 73 percent of the outages. The difference between actual restoration time and the first ETOR during the December 2002 storms averaged 11.52 hours, while the differences between the actual restoration time and first ETOR during the November 2002 storms and the November 2001 storm were 6.25 hours and 5.14 hours, respectively.

During storm events, an emergency plan is used to supplement normal call center operations in responding to the storm. The emergency plans cover extending hours, adding service representatives and conducting daily conference calls during storms to review and assess operations performance. In addition, during storm events, one or more of PG&E's Operations Emergency Centers is activated to expedite the deployment of restoration resources and assist in outage communications.

As shown in Table 2 below, PG&E's SAIFI has been improving, from a high of 1.709 in 1996 to a low of 1.112 in 2002.[9] PG&E's SAIFI from 1999-2002 was better than the average performance from 1996-1998.

TABLE 2

Year	SAIFI Major Events Excluded	SAIFI Major Events Included
1996	1.709	2.462
1997	1.639	1.700
1998	1.659	2.130
1999	1.477	1.481
2000	1.410	1.413
2001	1.439	1.559
2002	1.112	1.670
1996-1998 Average	1.67	2.10
1999-2002 Average	1.36	1.53

[9] Exhibit 13, Table 2-4, p.2-16

Similarly, Table 3 shows that while PG&E's SAIDI performance has fluctuated from year to year, PG&E's average SAIDI performance from 1999-2002 has improved slightly relative to PG&E's average SAIDI performance from 1996-1998.[10]

TABLE 3

Year	SAIDI Major Events Excluded	SAIDI Major Events Included
1996	178.1	347.0
1997	161.8	171.3
1998	180.0	317.0
1999	156.7	157.2
2000	167.9	168.4
2001	211.8	249.1
2002	139.2	381.9
1996-1998 Average	173.3	278.43
1999-2002 Average	168.9	239.03

5. PG&E's December 2002 Storm Response

In December 2002, PG&E and its customers were affected by a series of severe storms that brought heavy rains and hurricane-force winds to central and northern California. Two severe storms, occurring on December 14 and December 16, were followed by two additional storms of lesser magnitude on December 19 and December 21; all four storms were characterized by high wind conditions and periods of heavy rain and thundershowers. During those storms,

[10] Exhibit 13, Table 2-5, p.2-17.

thousands of PG&E customers experienced power outages, with many customers experiencing outages for extended periods of time.

PG&E states that the storm on December 14, 2002, was one of the worst 10 storms since 1995 and the December 16, 2002, storm was the second most severe storm to hit PG&E's service territory in the last 20 years.[11] The December 14 and 16 storms were characterized by sustained winds reaching 49 miles per hour and lasting up to 11 hours. Peak wind speeds during these two storms reached 100 miles per hour and over 10 inches of rain fell. The storms of December 19 and 21 delivered wind gusts of 30 to 50 miles per hour throughout the service area, accompanied by up to two inches of additional rainfall.

The series of storms caused significant damage to PG&E's electric distribution facilities, resulting in 1.97 million customer interruptions. PG&E reports that 1.3 million customers experienced service interruptions, with approximately 900,000 customers experiencing one outage, approximately 250,000 customers experiencing two outages, and approximately 150,000 customers experiencing three or more outages over the course of the storms. Some customers experienced outages that extended for several days.

PG&E's distribution system suffered damage to 2,056 distribution poles and pole hardware, 817 distribution transformers, and 3,884 spans of primary, secondary, and service conductors. PG&E's transmission system suffered damage to approximately 237 wood poles, one transmission tower, and 267 spans of transmission conductor. Over 3,600 field workers responded to restore

[11] PG&E Exhibit 12, p. 2-2 (As measured by the number of hours of sustained wind of 35 miles per hour or greater in Redding and at the San Francisco Airport).

service in harsh wind and rain conditions. The majority of the storm damage was tree-related.[12]

During the nine-day period beginning December 13, 2002 and ending December 21, 2002, PG&E's call centers and representatives received 1.8 million calls, compared to the 300,000 that would normally occur over an eight-day period. Of the 1.8 million customer calls received, call center representatives handled approximately 290,000 customer calls and IVR units handled approximately 1.5 million calls. Many customers contacted PG&E and the Commission to express concern about multiple, extended outages and their difficulties in contacting PG&E or receiving information from PG&E.

PG&E claims that its response to the December 2002 storms was reasonable. PG&E states that the December 2002 storms were unusual in that the two weather systems on December 14 and 16 were severe, and close together in time. PG&E states that the multiple storm fronts resulted in many circuits suffering repetitive damage, forcing PG&E to continually reprioritize restoration efforts and resource deployment plans in order to make conditions safe and assess the new damage and repair requirements. The resulting effect was that many customers were interrupted more than once and many other customers suffered extended outages due to the resource deployment needs (e.g., crews planned to be deployed to smaller outages from an earlier storm were redirected to larger outages from subsequent storms).

PG&E maintains that the outages that occurred during the storms were not caused by a lack of maintenance or a lack of tree-trimming. PG&E states that it currently trims or removes approximately two million trees per year, yet

[12] PG&E, Exhibit 12, p. 2-6, Figure 2-4.

60 percent of the outages were tree-related. PG&E also reports that it has increased the number of pole replacements since 1999, yet over 2,000 poles or associated pole hardware were damaged during the storms. PG&E believes that this indicates that the magnitude of the damage that occurred was unavoidable and cannot be attributed to a lack of maintenance, lack of tree trimming, or lack of pole replacements.

PG&E demonstrated that it met the ASA standard from 1996 through December 2002, with small variances in January 2001 and February 2001 during the energy crisis. During the storm period, from December 13-21, 2002, the call centers maintained a 21-second ASA, and only 236 customers received a busy signal. PG&E believes that this result demonstrates that its call center performance was reasonable. However, PG&E admits that following the conversion to the new CIS in December 2002, the call centers experienced a substantial increase in the time required to handle customers' calls and PG&E has not been able to meet the ASA standard since.

PG&E also argues that its OIS performed adequately during the December 2002 storm event. PG&E bases this claim in part on the fact that the average restoration time for all outages was less than 8 hours, more than 1.5 hours less than the performance standard set in GO 166. PG&E acknowledges that the difference between the first ETOR and the actual restoration time during the December 2002 storms was considerably larger than the differences observed during other major events but PG&E believes that this difference is largely due to the multiple severe storms causing ETORs to be revised several times by the time power was actually restored.

PG&E also admits that it identified several problems associated with its field restoration, outage communications, and call center systems during the December 2002 storms.

The field restoration and outage communications problems are listed below.

- PG&E learned from various police and fire departments that they were dissatisfied with PG&E's handling of their emergency calls regarding hazards associated with PG&E's facilities during the storms. PG&E admits that calls from emergency personnel were not handled consistently among the various Operations Emergency Centers, resulting in some police and fire personnel standing by hazardous conditions for excessive periods of time during the storms.

- Some customers who suffered service interruptions during the first storm remained out of power when the second storm hit, and some were placed in the back of the queue for outage restoration.

- The degree of detail provided by the field assessment personal varied considerably during the December 2002 storm event. Since the written assessments were not always detailed enough to accurately determine the resource and material needs, the ETOR was negatively affected.

- PG&E has three separate computer systems that require data to provide assistance in outage management and communication. These three systems are not currently connected, and require three separate entries to store complete outage information. Outage restoration is delayed by the time it takes to input data into these three systems, rather than into one integrated system.

- The circuit maps currently in the OIS are not always detailed enough to identify the specific transformer affected by the outage. In addition, due to the level of system detail currently in OIS, the OIS may indicate a greater number of customers out of service than are actually experiencing an outage. The overall effect is providing potentially inaccurate information to customers.

- During the December 2002 storms, some customers were informed that PG&E could not find a record of their earlier call. OIS software that addresses single customer outage information was originally configured so that a single customer outage would be "aged off" after 30 minutes. The "aged off" outages would not be prioritized along with multiple customer outages, but would be managed within the FAS. During the December 2002 storms, when the system "aged off" the single customer outage, it inadvertently deleted the recorded history of that outage. In an effort to temporarily resolve this problem, the aged off feature was disabled. The resulting number of single customer outages on the OIS made the system slower and the dispatcher's job more difficult. PG&E applied a software change to eliminate the record from being deleted and allowed PG&E to turn the "aged off" script back on.

PG&E's call centers also experienced some technical complications during the December 2002 storms as follows:

- A small number of customers received a busy signal on December 14, 2002 (236 callers of 414,903 calls received a busy signal).

- Some customers expressed concern that after making an initial call to report their outage in the Outage VRO system, they were presented with a message stating "We are not aware of a power outage at your location" when making a subsequent call to obtain the ETOR update.

- Some callers experienced a period of silence and a call ending message when waiting for an outage status message to play in the VRU.

- Some customers experiencing outages said they did not have an option to talk with a service representative when they called.

- Some outage restoration callbacks by the VRU system were delayed because of the high volume of callback requests.

- Some customers were unaware of the significance and advantage of having their phone number listed on their account record in PG&E's CIS.

To address these problems, PG&E identified and implemented several process and technology improvements intended to improve its outage communication and field restoration process as well as its call center performance during future storms. The identified changes to the outage communication and field restoration process include:

- PG&E is implementing a process by which all calls from emergency agencies will be routed to service dispatch operators located throughout PG&E's service territory. These personnel will be trained to handle these calls during both routine and emergency operations, which will ensure consistent prioritization of these calls.

- PG&E has modified its restoration prioritization to balance the length of time small numbers of customers are out of power with the need to restore the largest numbers of customers. Specifically, PG&E intends to identify emergency response personnel in each of its OECs who are responsible during major storms to focus attention on small primary level outages and single customer outages.

- Utilizing mobile data terminal units currently in Troubleman and Gas Service Representative trucks to accelerate the input of outage cause and damage assessment information to the Operations Emergency Centers.

- Integrating three of the company's internal information control systems to reduce the number of entries required by a system operator. The three systems that would be integrated include the Supervisory Control and Data Acquisition System (SCADA), the Distribution Operators Logging Information Program (DOLIP), and the OIS.
- Improving the mapping associations within OIS to better provide accurate numbers of customers affected by outages and more accurate outage information on a real time basis.
- Eliminating the "aged off" feature of the OIS and developing software to more efficiently manage single customer outages.

PG&E has also taken steps to eliminate or reduce the occurrence of call center problems. For example, PG&E states that it has re-programmed the VRU system to preclude customers from experiencing a period of silence and call ending message when waiting for an outage status message. PG&E has also added a special toll-free number for customers who are without power for 48 hours or more to improve the ability of those customers to speak with service representatives. PG&E has undertaken a communication campaign urging customers to ensure that the correct phone number is on record for their service address to allow customers to better receive timely and accurate outage information. PG&E also states that it is taking action to reduce its call center ASA, including 1) hiring and training an additional 100 service representatives, 2) improving service representatives' call handling efficiency, and 3) improving the customer information system's performance.

PG&E states that its overall response to the December 2002 storms is consistent with the "adequate service" standard discussed in the last PG&E GRC decision and in the context of past Commission decisions addressing the reasonableness of storm response activities, including D.95-09-073, the decision on PG&E's response to the January and March 1995 storms, D.99-06-020, the decision on PG&E's response to the December 1995 storm, and the decisions adopting standards and requirements for storm response, inspection, maintenance and reliability. (D.96-09-045 and D.98-07-097)

PG&E maintains that throughout this phase of the GRC, no party presented evidence demonstrating that PG&E's response to the December 2002 storm event was unreasonable or that PG&E's maintenance activities or work practices contributed to the amount of damage incurred.[13] PG&E argues that the severe damage suffered by its system cannot be attributed to a lack of maintenance, lack of tree trimming or lack of pole replacements. PG&E argues that it effectively utilized the resources at its disposal to restore service caused by the series of storms that began on December 12, 2002. PG&E points out that although ORA and its consultant Stone and Webster asserted that various factors associated with PG&E's performance negatively affected service restoration, neither ORA nor Stone and Webster claimed that these factors resulted in unreasonable performance. PG&E also points out that the PG&E/ORA joint testimony identifies improvement opportunities and plans to better document and measure performance, but does not include any findings of lack of compliance with any existing standard or code.

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[13] PG&E Opening Brief, pg. 3.

Although PG&E maintains that its response to the December 2002 storms was reasonable, it recognizes that there has been public dissatisfaction with its storm performance. PG&E acknowledges that the damage cause by these successive storms resulted in many customers experiencing multiple interruptions of service. Because of the severity of the damage, the high number of outages, and the number of repeat outages, approximately 50,000 customers were without power for more than two days.

PG&E explains that because the storms did not meet the definition of a "Major Outage" under GO 166, the service restoration standards and call center standards applicable to measured events do not apply. Nevertheless, PG&E notes, its performance during the storm met the requirements of GO 166. PG&E also notes that its reliability performance in 2002 (excluding major events) as measured using the SAIDI and SAIFI was better than any year going back at least 10 years. The outages associated with the December 2002 storms are not included in the calculation of SAIDI and SAIFI for 2002, however, because they met the Commission's definition of "excludable major event" since more than 10 percent of PG&E's customers were without power during each of these events.

ORA agrees with PG&E that the December 2002 storms were severe, and that the current definition of "Major Outage" within GO 166 prevents the restoration benchmark from being applied to the December 2002 storm event. ORA finds, however, that certain of PG&E's actions may have contributed negatively to the outage durations experienced by customers and offers several recommendations designed to improve PG&E's performance, as well as the Commission's ability to effectively evaluate PG&E's performance. In particular, ORA believes that PG&E's restoration performance would have been more effective if PG&E had mobilized and deployed additional staff earlier in the storms, provided better training to trouble assessors, and developed a clear policy to ensure that no customers are left without service for an inordinate amount of time. ORA highlights the significant differences in performance among PG&E's divisions and recommends that reliability measurement standards be reported at the division and operating area level as well as at the system level. ORA also recommends that the definitions used for Excludable Major Event and Major Outages be made consistent and that outage performance be measured against realistic benchmarks.

TURN maintains that the Commission cannot find PG&E's response to the December 2002 storm reasonable. In particular, TURN finds that PG&E's failure to adequately manage the outage information flows in its system, resulting in reported single outages being "aged off" without a record of the outage, demonstrates performance that was not reasonable. TURN points to the fact that PG&E has discontinued its use of the FAS during major events and has decided to modify its OIS as indications that PG&E acknowledges that its performance was unreasonable. TURN points out that not only is there no finding of reasonableness in ORA's testimony, or the PG&E / ORA joint testimony, but PG&E specifically acknowledges that customers' complaints regarding outage communications during storms led to various PG&E proposals to modify and improve such outage communications in the future.

CUE argues that PG&E's service is far less reliable than Southern California Edison's (SCE's) or San Diego Gas and Electric Company's (SDG&E's). According to CUE, outages on the PG&E system are more frequent and of longer duration than outages of the other California utilities. Of particular concern to CUE is that PG&E's average restoration time, as measured by CAIDI, has increased as PG&E field staffing levels have decreased. CUE believes that the Commission should adopt a reliability performance incentive mechanism to improve PG&E's performance.

6. Parties' Recommendations

The purpose of this phase of the GRC is twofold; to review PG&E's storm response and reliability performance and to identify any changes necessary in the methods used to measure and evaluate PG&E's performance. PG&E submits that its December 2002 storm response and reliability performance is reasonable, consistent with the "adequate service" standard described in D.00-02-046. Other parties suggest that PG&E should have performed better and recommend various measures designed to improve PG&E's reliability performance and storm response.

6.1 PG&E

PG&E has identified several specific storm and reliability issues that it believes should be addressed in order to improve performance. PG&E's testimony includes a list of "improvement initiatives" designed to address these issues and improve performance[14], particularly during major events. The improvement initiatives include:

a. Modify restoration prioritization to balance the length of time small numbers of customers are out of power with the need to restore the largest number of customers as quickly as possible.

b. Simplify the routing of calls from emergency agencies to PG&E to improve the dispatching of PG&E resources to relieve police and fire agency personnel of the need to standby on site.

c. Develop additional software to enhance the ability within OIS to increase focus on single customer outages during

[14] Exhibit PG&E 12, page 1-10.

major events to improve communication with customers and reduce outage duration;

d. PG&E will link its OIS with the mobile data terminals in the field to accelerate the input of outage cause and damage assessment information into the Operations Emergency Centers and ETOR data into the OIS to improve the speed of assessing damage and sharing outage information with customers;

e. Integrate the three existing outage databases (the Supervisory Control and Data Acquisitions, OIS and DOLIP) to reduce the number of manual entries an operator must make to improve efficiency and reduce outage duration;

f. Enhance mapping associations within the OIS so that smaller portions of PG&E's circuitry can be pinpointed for purposes of determining on a real time basis a more accurate number of customers affected by outages and more accurate outage information;

g. Add new toll-free number for customers who are without power for more than 48 hours;

h. Implement a campaign to urge customers to verify the accuracy of the phone number on their PG&E bill.

PG&E has already implemented some of the improvement initiatives because it believes the Commission desires improved performance during storm events, but the costs to implement some of these measures exceed the revenues requested by PG&E in its November 2002 application. PG&E maintains that the incremental costs associated with the initiatives must be added to PG&E's revenue requirement to ensure adequate funding of all necessary system work.

PG&E also identifies three additional suggestions for reliability improvements. First, PG&E suggests that the Commission could direct PG&E to accelerate its ongoing program to fuse overhead distribution tap lines. PG&E

states that installing overhead distribution line tap fuses will help reduce SAIDI by reducing the number of customers affected by an outage and helping to pinpoint the location of the fault. PG&E included $5.4 million in its 2003 forecast for this work, but accelerating the annual amount of fuse work by 25 percent, would increase annual expenditures by approximately $1.35 million.

A second proposal is a tree-trimming pilot designed to evaluate the reliability benefits of selectively removing large branches that have the potential to fall into lines even though they are located outside the trim zone required by GO 95. PG&E estimates this pilot would cost $10 million per year for three years, but has not prepared a cost-benefit analysis or developed the details of the pilot program. Third, PG&E suggests that the Commission could consider a Performance Based Ratemaking-style performance incentive mechanism.

PG&E initially proposed that the Commission adopt a new memorandum account to record the incremental costs PG&E incurs to comply with any new standards or metrics adopted through the storm and reliability phase. PG&E also proposed that the Commission establish a future stage of this proceeding to adopt an incremental revenue requirement associated with the cost of compliance with new standards or metrics and to review the reasonableness of the costs recorded in the memorandum account.

PG&E also requested that the Commission approve an additional $7.98 million (in 2000 dollars) beyond its forecast expenses in Federal Energy Regulatory Commission (FERC) Account 588 – Miscellaneous Electric Distribution Expense and an additional $1.8 million in common utility plant for the upgrades to the OIS.

On July 10, 2003 PG&E and ORA filed jointly-sponsored testimony intended to resolve all of the storm and reliability issues contained in ORA's testimony and PG&E's rebuttal to ORA's testimony, with the exception of the issues surrounding PG&E's Safety Net Program.[15] PG&E and ORA agree that the December 2002 storms were severe, and that PG&E's storm performance should be improved. The PG&E/ORA joint testimony contains nine agreements that are intended to result in reliability performance improvements, particularly during major storm events. The nine agreements are spelled out in Appendix A. The PG&E/ORA joint testimony constitutes PG&E's current position regarding reporting and monitoring storm and reliability performance, and funding to improve outage communication performance.

PG&E opposed CUE's initial performance mechanism proposal, arguing that: (1) it relies on the unsupported assumption that customers are willing to pay more for additional reliability and (2) the performance targets require an unreasonably high level of reliability improvement, without a demonstrated need for the level of reliability improvement proposed. PG&E also argued that CUE's proposal would require the Commission to abandon its prior policy of adequate service without providing any evidence to support a different standard.

In response to CUE's proposal, PG&E recommended an alternative reliability performance mechanism in which the target reliability levels would remain fixed at the 1998-2002 average performance levels for the term of the mechanism. PG&E recommended that any consideration of improvement

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[15] The issues surrounding PG&E's Safety Net Program were submitted in briefs in the storm and reliability phase of the proceeding, but are also addressed in a Motion for Approval of Settlement Agreement filed by PG&E, ORA, TURN, Aglet, the Modesto Irrigation District, the Natural Resources Defense Council, and the Agricultural Energy Consumers Alliance on September 15, 2003. The Safety Net Program will be considered along with the Motion in the revenue requirement phase of PG&E's TY 2003 GRC.

targets be postponed until PG&E can present the results of a customer value of service study prior to its next GRC proceeding.

PG&E now recommends that the Commission approve the joint recommendation between PG&E and CUE regarding a mechanism to improve reliability through incentives and additional funding.

The PG&E/CUE proposal contains the following elements:

- The term of the proposal is six years, 2004 through 2009.
- The performance metrics are the SAIDI and the SAIFI;
- The SAIDI target in terms of minutes per customer, by year, is: 171, 164, 158, 151,151,151;
- The SAIFI target in terms of interruptions per customer, by year is 1.42, 1.33, 1.24, 1.16, 1.16, 1.16;
- The maximum annual reward and penalty is $31.6 million for SAIDI and $10 million for SAIFI;
- The Deadband is 4.2 minutes per year for SAIDI and 0.05 outages per year for SAIFI on either side of the target;
- The Liveband is 15.8 minutes per year for SAIDI and 0.10 outages per year for SAIFI, for livebands on each side of the targets; and
- An Additional Revenue Requirement of $27 million annually for six years to be used for reliability improvement expenditures, subject to balancing account treatment;
- Any revenues not spent by PG&E in 2004, 2005, and 2006 would be carried over to the following years, up to 2007. Unspent revenues at the end of each year 2007, 2008, 2009

> would be credited back to ratepayers at the end of each year.

PG&E states that it supports improving reliability through an appropriate incentive mechanism as long as additional revenues are authorized. PG&E believes the PG&E/CUE proposed incentive mechanism strikes the right balance between improved reliability targets and additional revenues.

PG&E does not support CUE's proposal for an Employee Safety Performance Mechanism. PG&E maintains that it already has a comprehensive and effective program to promote safety and health, including a new employee orientation, a Code of Safe Work Practices, safety and health procedures, internal safety, health and compliance audits, and a Public Safety Information program. PG&E claims that these programs have resulted in continued improvement in safety performance in recent years, and that the Employee Safety Performance Mechanism is not necessary. If the Commission adopts a Safety Performance Mechanism, however, PG&E recommends that the Commission adopt Lost Workdays as the basis for monitoring and evaluating its performance, instead of the OSHA recordables rate, because recent changes in OSHA regulations for reporting injury or illness make it impossible to develop an OSHA recordables metric that accurately compares recent statistics with historical records in any meaningful way nor does it measure the severity of injuries.

Finally, PG&E recommends that the Commission adopt a telephone service level (TSL) standard to replace the ASA requirement during normal conditions. PG&E states that it is the only major utility subject to an ASA standard and that adoption of its request would subject all Commission-jurisdictional utilities to the same type of call center performance standard.

6.2 CUE

CUE suggests that the increase in PG&E's restoration time is explained primarily by a decrease in electric field service personnel per customer. CUE compares PG&E's electric field service personnel staffing levels since 1990 with PG&E's Customer Average Interruption Duration Index (CAIDI) levels since 1990 and argues that there is a strong correlation between the two. CUE admits that both outage frequency and outage duration are affected to an extent by weather, system design and maintenance, as well as staffing levels, but argues that outage duration on PG&E's system is more closely related to staffing levels. CUE explains that its argument is based primarily on a review of PG&E's field staffing statistics. CUE believes that with incentives and resources, PG&E could, and would, provide better reliability to its customers. CUE also believes that the public response to the December 2002 storms shows that customers want better service.

CUE initially recommended a reward and penalty incentive mechanism that set performance targets equal to PG&E's 2002 performance levels for SAIDI, SAIFI, and MAIFI and became progressively more stringent, to give PG&E economic incentives to improve reliability. CUE's initial proposal also included an additional $72.5 million annual revenue requirement and a maximum award or penalty of $145.2 million per year. CUE asserted that if PG&E does not improve reliability with the incremental revenue, ratepayers would be reimbursed through penalties. On the other hand, if PG&E succeeds in improving reliability and earns rewards, CUE argues that the cost of the incremental annual revenue requirements along with the additional reward payments would be consistent with existing value of service studies and incentive rates previously adopted for SCE and SDG&E.

After the hearings on the storm and reliability issues, PG&E and CUE served joint testimony recommending that the Commission approve a joint proposal for a reliability incentive mechanism. CUE argues that although the PG&E/CUE mechanism would not improve reliability as much as the original CUE proposal, it preserves the critical features of its original proposal, and it provides for some improvement at a lower cost.

CUE also argues that the Commission should adopt the CUE Employee Safety Incentive Mechanism. CUE believes that an employee safety mechanism is particularly important in the context of reliability performance incentives, where there is a direct economic incentive to restore service as quickly as possible. CUE states that its proposed safety incentive is based on mechanisms previously adopted for SCE and SDG&E, and uses the standard OSHA reporting category, "OSHA Recordable Injuries and Illnesses Frequency Rate" (the OSHA recordables rate), with a benchmark set at 5.42, PG&E's most recently attained safety level.[16] CUE recommends no deadband, and an incentive rate of $342,000 per 0.1 change in the annual OSHA recordables rate, with the liveband set at plus or minus 2.5, comparable to the mechanism CUE has proposed for SCE in its GRC. The maximum annual reward or penalty under the employee safety incentive mechanism would be $8.55 million.

[16] The OSHA recordables rate corresponds to the number of job-related injuries or illnesses per year per 100 full-time-equivalent employees. CUE notes that the actual OSHA recordables rate in 2002 was 6.67. However this reflected a change from a 90-day lag period to a 7-day lag period in reporting OSHA-recordable injuries and illnesses. CUE calculates that the 2002 data includes an extra 83 days of OSHA recordables, or 23 percent more days than years before or since (83/365 = .23). Accordingly, CUE divides the actual OSHA recordables rate of 6.67 by 1.23 resulting in a rate of 5.42.

6.3 ORA

The majority of ORA's testimony and recommendations centered around the adequacy of the Commission's existing standards and measures for evaluating PG&E's reliability and outage response. ORA explains that despite the severity of the December 2002 storms, the Commission's existing reliability and emergency response standards could not be used as a benchmark to evaluate PG&E's response to the storms because the storms did not meet the definition of "Major Outage" within GO 166. In order to ensure that the Commission is able to effectively assess PG&E's storm response and reliability performance in the future, ORA initially recommended that the definitions used for "Excludable Major Event," "Major Outage" and "Measured Event" be made consistent.

ORA is concerned that conflicts between the definitions and requirements contained within GO 166 and D.96-09-045 create a lack of uniformity in how PG&E measures its reliability performance and how these measures are then compared with the restoration benchmark used by the Commission to measure PG&E's performance. In particular, ORA notes that while the GO 166 standards only apply during a "Major Outage," defined as a situation where 10% of PG&E's customers simultaneously experience an outage, D.96-09-045 defines an Excludable Major Event as an event that "affects" 10% of its customers or 15 % of its facilities, whichever is less for each event, with no mention of simultaneous or cumulative, and allows PG&E to exclude such events from its reliability indices. ORA suggests that by allowing excludable major events to be determined using a 10% cumulative basis, while the restoration benchmark is applied only during outage events that affect 10% of customers simultaneously, PG&E is getting the best of both worlds.

ORA also notes that while GO 166 clearly defines how start and end times for a Measured Event are to be determined, D.96-09-045 does not define start and end points for an excludable major event. As a result, the utilities have developed different methods of calculating the start and end points of such events.

ORA also notes that while GO 166 requires the Commission to investigate major outages, the Commission is not required to investigate excludable major events. ORA recommends that the various definitions related to SAIDI, SAIFI, CAIDI, MAIFI (including specific requirements detailing how these are measured and calculated), Major Outage, Measured Events, and benchmarks for measuring reliability performance should be incorporated into one single regulation. ORA further recommends that the terms Major Outage, Measured Event, and Excludable Major Event, be consolidated into one term, “Major Outage,” and all major outages should be investigated before the utilities are allowed to exclude them from the reliability indices.

ORA suggests that the definition of major outages, benchmarks used to measure performance during major outages, and determinations used to exclude events from reliability indices during major outages should be based on a clearly defined percentage of customers out of service on a cumulative basis. ORA also suggests that the Commission establish a process to examine if the level of the CAIDI benchmark in GO 166 is realistic.

ORA initially recommended that reliability measurements be reported at the operating divisions and operating area level as well as at the system level. ORA is concerned that system level reliability indices may reflect high reliability, while masking lower reliability experienced by customers at the division level, especially for an area as large and diverse as that served by PG&E. ORA’s consultants report that while system-wide SAIDI values show an overall decrease over the five-year period from 1998-2001, five divisions exhibited an upward trend, three remained unchanged, two showed a slight downward trend, and seven exhibited a modest downward trend. ORA's consultants also noted that a number of comparable divisions (in terms of area, number of customers, etc.) exhibited relatively large differences in reliability.

ORA recommends using a five-year rolling average of current performance measurement as a benchmark for reliability performance. ORA suggests that PG&E should be required to investigate deviations, on a division or area basis, when performance varies by over 10% from the benchmark to determine the cause and report findings to the Commission.

ORA also suggests that the Commission direct PG&E to implement the existing measures in its action plans as well as explore additional technical measures to improve the accuracy of its VRU systems. Similarly, ORA suggests that PG&E review its OIS, CIS, Field Automation System (FAS), VRU and all customer interface and response systems, to identify any needed adjustments that would aid PG&E's decision makers in making appropriate resource deployments to address outages. ORA also agreed with PG&E's initiative to develop a policy to insure that no customers are left without service for an inordinate amount of time. Although ORA supported PG&E's improvement initiatives, it expressed concerns regarding the limited data presented in support of the initiatives. ORA supported PG&E's proposal to accelerate the installation of overhead line fuses, but argued that no additional funding is necessary to accelerate the program because sufficient funds already exist in PG&E's base 2003 revenue requirement request. ORA also initially recommended that PG&E be directed to base value of service on empirical analysis and present the results to the Commission no later than its next GRC.

As described in Section 6.1 above, ORA and PG&E reached agreement on all of the contested issues raised by ORA with the exception of the issues surrounding PG&E's Safety Net Program. ORA asks the Commission to approve the recommendations and agreements in the jointly-sponsored testimony of PG&E and ORA in the Storm and Reliability phase of PG&E's TY 2003 GRC. With respect to PG&E's Safety Net Program, ORA recommends that the Commission make PG&E's Safety Net Program mandatory, increase the outage payments to $50, remove the $100 cap, and require PG&E to report on the payments.

Finally, ORA recommends that the Commission reject the jointly sponsored testimony of PG&E and CUE proposing a reliability performance incentive mechanism as well as the alternative reliability incentive proposal of PG&E. ORA argues that the incentive proposals are too expensive and do not result in increased reliability beyond that already anticipated.

6.4 TURN

TURN recommends that the Commission reject the PG&E/CUE proposal for a separate reliability funding mechanism. TURN suggests that it would be appropriate for the Commission to establish reliability performance measures based on recent historical averages of reliability performance, but argues that any reliability performance standard should account for the impact of system improvements that are already in progress and those forecast for completion during the term of the mechanism. TURN argues that the reliability performance targets in the PG&E/CUE mechanism fail to reflect a reasonable forecast of future performance.

In particular, TURN notes that PG&E's tap line fuse installation program, designed to limit the number of customers affected by outages, is expected to benefit both SAIDI and SAIFI, and is described by PG&E as providing "relatively significant reliability benefits at a low cost."[17] According to TURN, PG&E stated that "the intent of this project is to achieve an estimated 10 percent reduction in SAIDI upon completion of the work." TURN maintains that the Commission should assume that the completion of this program will result in almost 17 minutes of SAIDI improvement based on testimony offered by PG&E witness Camara. In addition, TURN notes that PG&E witness Blastic estimated that the tap line fuse installation program would result in a reduction of 0.1 outages in the SAIFI by 2007 and that the reliability benefits of the fuse program are expected to continue for the 30-year useful life of these devices.[18]

TURN cites PG&E witness Bhattacharya's testimony stating that PG&E's fuse replacement, pole replacement, and substation asset replacement programs are likely to contribute to improved reliability performance in the coming years as support for its position.[19] TURN also points out that PG&E witness Battacharya testified that PG&E's expenditures in Major Work Category (MWC) 49 were expected to triple over the next five years. TURN argues that the Commission should assume that a tripling of expenditures in this MWC would have a positive impact on reliability that would produce a reduction in both SAIDI and SAIFI and that any such reductions must be factored into the calculation of reliability performance targets.

TURN also recommends that if any reliability measures are adopted in this proceeding, they should recognize the extreme rate sensitivity of current

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[17] Exhibit 917, Data Response of Manuel Camara to ORA DR 358-12, page 1.

[18] RT 319.

[19] RT 182.

customers and ensure that any desired reliability benefits are achieved at the lowest possible cost.

TURN also recommends that the Commission reject Agreement 6 and Agreement 7 of the PG&E/ORA proposal. TURN opposes Agreement 6 because it would direct PG&E to review and assess data from previous value of service studies rather than conducting a new value of service study. TURN argues that there is no useful purpose in revisiting data that is over ten years old and has become increasingly irrelevant in light of the significant events that have occurred in the intervening years. TURN recommends that before decisions are made based on value of service data, a new value of service study by major class of PG&E's customers should be undertaken. TURN also recommends that any such study research the value of service from both the point of view of willingness to pay and willingness to accept values.

TURN opposes Agreement 7 of the PG&E/ORA proposal because it would allow PG&E to collect $15.9 million in funding for four projects associated with OIS and emergency response system upgrades, despite the fact that certain of the proposed changes should have been incorporated into the original OIS system.

Specifically, TURN is opposed to PG&E's request for $0.8 million in hardware and $3.25 million in expense to integrate three separate computer systems on the grounds that this integration should have been designed into the new OIS that was capitalized in 1999. TURN opposes PG&E's request for $1 million in capital and $2.45 million in expense to remedy the treatment of single customer outages that are dropped off the system after 30 minutes for the same reason. If TURN's recommendations on these two projects are not approved, TURN recommends that the expense should be averaged over 3 years.

TURN also argues that the $3.05 million expense associated with the software upgrade for the mobile data terminals should be averaged over 3 years instead of one because it is a one-time expense. TURN also argues that the mapping expense of $7.38 million should be averaged over 5 years consistent with the expected length of the project and the amount of projected expenditures per year. TURN does not oppose the rest of the PG&E/ORA proposal.

TURN also does not oppose PG&E's request to replace the ASA standard with a TSL standard as long as the adopted standard reflects the same performance level. TURN suggests that the TSL standard be set so that 80 percent of total calls during the month must be answered within 20 seconds. TURN also requests that PG&E provide it with the monthly reports on call center performance that are provided to ORA and the Commission.

6.5 Aglet

Aglet agrees with TURN and ORA that the Commission should reject the PG&E/CUE proposal. Aglet argues that the incentive mechanism proposed by CUE and PG&E is too expensive and is crippled by reliance on stale, uncertain value of service numbers.

Aglet agrees with TURN that PG&E's reliability will improve without an incentive mechanism for several reasons. First, PG&E's recorded costs and future budgets for reliability projects show a steady increase in funding. Second, there is general agreement that PG&E's program to fuse overhead distribution tap lines will improve reliability. Third, improved information technology and communication systems should improve worker response times and thereby improve measured reliability performance. Fourth, PG&E asserts that improved inspection and patrol practices will improve system reliability.[20]

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[20] Liikala-Seymore, Exhibit 13, p.3-22.

Aglet disagrees with CUE's assertion that the rate impact of $27 million of additional revenue requirement is minimal. Aglet explains that over the six-year period of the joint proposal, ratepayers would pay $162 million (6 x $27 million) in additional revenues and would be exposed to $249.6 million (6 x $41.6 million) of incentive payments. In addition, after the six-year period, ratepayers could also face rate recovery of unknown millions of dollars in undepreciated capital costs because the agreement provides that at the end of the program any undepreciated capital costs will be eligible for inclusion in rate base. Aglet suggests that it is possible that ratepayers could pay $400 million to $500 million in total revenues over the duration of the proposed incentive program.

Aglet also points out that although PG&E and CUE argue that the incentive mechanism benefits ratepayers, all three ratepayer groups strongly oppose it. According to Aglet, this opposition, in itself, is a very strong reason why the proposal should not be approved. Aglet recommends that if the Commission decides to approve an incentive mechanism, it should set any associated revenue requirements and ensuing rates subject to refund until completion of a new value of service study and cost allocation deliberations in the rate design phase of the GRC in order to prevent residential customers with lower values of service from being forced to subsidize larger customers with higher values of service.

For the same reason, Aglet argues that the Commission should order PG&E to produce a new value of service study. Agreement 6 of the ORA / PG&E joint testimony would allow PG&E to survey prior VOS studies and then determine – without participation by Aglet or other intervenors – whether a new VOS study is necessary. Aglet argues that there is no evidence to support the finding that a new VOS study is "not warranted," and that in fact there are three reasons for a new VOS study.

First, as stated above, the available VOS studies are stale. The two studies referred to by CUE and PG&E are over ten years old and the agreement with ORA does not indicate what other studies might be surveyed by PG&E. Second, there is general agreement that public perceptions of the electric power industry have changed since the initiation of industry restructuring. Third, accurate VOS information is needed to optimize utility resources and apply them to reliability improvements. Reliable VOS information will also be needed when the Commission addresses cost allocation issues. Therefore, if the Commission does approve the PG&E/CUE incentive proposal, Aglet argues that the Commission should also set the associated revenue requirement and ensuing rates subject to refund until completion of a new VOS study and cost allocation in the rate design phase of the proceeding.

Aglet believes the Commission should discourage system-wide averaging and averaging over several years of operations because both tend to dampen or reduce the variability of the performance metrics. Aglet recommends that the Commission review reliability at the district or division level for single-year periods first, with system-level measurements used as a secondary indicator. Aglet argues that there is no good reason to begin the measurement process by system-wide averaging or averaging over time, thereby losing information and reducing the performance risks that face the utility. Aglet believes this is especially true because the reliability measures already exclude major events.

Aglet also believes that the Commission should reject Agreement 7 of the PG&E/ORA proposal because it would result in retroactive ratemaking. Aglet argues that if the Commission adopts Agreement 7, it will not approve the proposed memorandum account until it reaches a decision in the instant reliability phase of the GRC, after PG&E has already spent "several million dollars" for the specific upgrades that are part of the joint recommendation.

Aglet argues that this would constitute retroactive ratemaking because the Commission has not authorized rate recovery of 2003 costs beyond adoption of current revenue requirements. Aglet asserts that PG&E and ORA have not shown that 2003 recorded costs are now booked to any account that would allow recovery. Aglet believes PG&E's current ratemaking accounts only allow debiting of authorized revenue requirements, not recorded costs, for the instant reliability upgrades. Aglet argues that as a matter of law, the Commission must deny rate recovery of 2003 costs that PG&E and ORA propose be recorded in the memorandum account prior to the effective date of a decision in this phase of the proceeding.

7. Discussion

7.1 Value of Service Study

Value of service provides a means to quantify the value customers place on reliable electric service. Value of service information allows the utility to make cost effective decisions that are consistent with customer's desires. PG&E did not prepare a value of service study as part of its 2003 GRC application and has not prepared a value of service study for at least a decade. PG&E developed an internal value of service guideline, Utility Operations Guideline G12003, in May 2001. The values in G12003 are not based on customer information or surveys, but are based on the value PG&E proposed to place on reliability as part of a performance-based ratemaking filing in September 2000. G12003 is used exclusively for the evaluation of discretionary reliability improvement projects. PG&E does not use G12003 to develop service restoration plans.

ORA initially recommended that PG&E change its method of valuing service but in joint testimony with PG&E supports a PG&E review of existing VOS studies to assess their usefulness. Aglet and TURN recommend a new VOS study. By virtue of its reliance on G12003 in development of the proposed performance incentive mechanism payments and rewards, CUE appears to support continued use of existing value of service assumptions.

ORA points out that the "values" in G12003 do not equate the value of reliability to customers with the value of system investment, but rather equate PG&E's proposed value of reliability with PG&E's estimated effect on reliability. ORA argues that these proposed values are not an adequate basis for operational decision making. Noting that PG&E has no plans to develop better value of service data, ORA recommended that PG&E base value of service on empirical analysis and present the results to the Commission by no later than the next rate case. ORA argued that operational decision-making should be linked to the value that PG&E's customers place on reliability and that these values would remain unknown until PG&E updates its value of service data.

ORA also pointed out that because G12003 uses three different measures of value of service (cents per customer minute of interruption, dollars per customer outage and dollars per line mile per outage) derived from different proposed metrics, which bear no direct relationship to each other, G12003 is internally inconsistent. ORA believes that using three different measures could result in inconsistent decision-making. ORA also recommended that the Commission require PG&E to consistently apply an empirically-based value of service metric, to service guarantees and storm response, in addition to investment planning.

PG&E argues that the value of service numbers in G12003 are consistent with other value of service literature, in particular, a 1992 survey paper by Woo and Pupp. PG&E states that: "Because the values are consistent with VOS literature, the numbers do in fact equate the value of reliability to customers with the value of system investment."

In their joint testimony, ORA and PG&E agree that a new VOS study is not necessary. Instead, PG&E and ORA agree that PG&E should perform an assessment of service values (a "VOS assessment") by December 31, 2004. The VOS assessment would analyze and appraise the differences within and among unspecified prior VOS studies, as well as the relative merit of "willingness to pay" versus "willingness to accept" and explain the derivation of proposed VOS values.

TURN recommends that before major investments and other decisions are made based on value of service, a new VOS study of PG&E's customers be done. TURN states that it does not understand ORA's suggestion for an empirical analysis short of undertaking a VOS survey. TURN believes that there are enough unknowns that any analysis based on past studies will not adequately answer the questions at hand. TURN also recommends that any such VOS study research the value of service from both the point of view of willingness to pay and willingness to accept.

TURN explains that values of service differ significantly by customer class. TURN believes that using existing VOS information to establish incentive mechanisms, like in CUE's proposal, is likely to lead to a situation where: 1) more reliability is paid for by the residential class than it wants, and 2) more reliability is provided to the residential class than it wants to pay for.

According to Aglet, the CUE/PG&E proposal is based on uncertain and out of date VOS information. The uncertainty stems from changed public perceptions about electric power. Aglet points out that one of CUE's calculations of VOS assumes that all costs of the Department of Water Resources contracts that the State of California executed in 2001 were directed toward improving SAIDI performance. Aglet argues, as does TURN, that this assumption is unrealistic and yields VOS figures that are too high.

Even ORA, who testified in the PG&E/ORA joint testimony that a "VOS assessment" is a sufficient mechanism to use in updating values of service, takes issue with the PG&E/CUE claim that the "adoption of additional reliability incentive expenditures are justified on a value–of-service basis." According to ORA, nowhere does the PG&E/CUE proposal indicate exactly which study, if any, the VOS data were obtained from. ORA believes that this is a very important omission because the PG&E/CUE proposal bases its calculation of rewards and penalties on VOS data. ORA argues that any performance mechanism should be based on the current values placed by affected ratepayers on that performance, not on an unspecified, outdated, value of service study that may have been conducted sometime in 1993, or perhaps 1990, for another utility. Since PG&E has not done a VOS study for at least a decade, the record does not contain any value of service information that would capture the tremendous changes that have transpired in the electric industry in the last seven to eight years.

Moreover, even PG&E testified that a new VOS study should be done prior to initiating any improvements based on customer value of service, suggesting that "any consideration of improvement targets [should] be held until PG&E can present the results of a customer value of service study… prior to PG&E's next GRC proceeding."[21] PG&E's witness Bhattacharya testified that "a lot of things has [sic] happened since G12003 was put together…we had the energy crisis and customer's expectation on reliability has, I would believe,

[21] Exhibit 18, p.1-11

changed. Customers willingness to pay or expectation of reliability has changed."[22]

Although the values contained in G12003 may be consistent with the Woo and Pupp study, we cannot find that they adequately represent PG&E's customers' current value of service. Additionally, as PG&E admits, the VOS data underlying G12003 does not indicate PG&E customers' willingness to pay for added reliability. It is time for PG&E to prepare a new value of service study. The most recent PG&E study was prepared in 1993, with updated estimates prepared for PG&E's September 2000 Performance-Based Ratemaking (PBR) filing. All parties agree that in the intervening years, electric restructuring and the electricity crisis may have significantly altered PG&E's customer's value of service. In addition, great changes have occurred in the California economy in general in the past few years that may also have affected PG&E's customer's value of service. A review of existing studies will likely result in parties making the same claims in the next GRC as they have here – that the studies are too dated.

PG&E's latest VOS survey was prepared in 1993. SCE prepared a 1999 update to its VOS, which quoted PG&E's 1993 study and translated those values to 1998 dollars, but a study of SCE's customers is not necessarily useful in determining the VOS of PG&E's customers. As TURN points out, for the one outage scenario that was common to both PG&E's 1993 study and SCE's 1999 update, PG&E's residential customers had a higher value of service than SCE's (PG&E's VOS/unserved kWh was $4.37 and SCE's was $2.52). Furthermore, TURN also points out that even SCE's 2000 study predates the energy crisis and

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[22] RT 136

that the record does not contain value of service information from any utility that shows whether or not the energy crisis or the 1995 or 2002 storms have changed PG&E's customers' perceptions of their value of service.

We agree with TURN that while an assessment of prior studies may offer some insight into how to better prepare a VOS study, such an assessment of prior studies will not shed any light on customers' current value of service, nor will it evaluate current customer's willingness to pay for improved reliability. For this reason, we decline to approve PG&E/ORA Agreement 6. Instead, we direct PG&E to prepare a new VOS study prior to its next GRC. PG&E should prepare a proposed value of service study approach and cost estimate for review and comment by ORA and other interested parties. PG&E should file its proposal by advice letter. At a minimum, the new VOS study should include a "willingness to pay" element.

7.2 Funding OIS Improvements

Agreement 7 of the PG&E/ORA proposal would allow PG&E to establish a memorandum account to record the costs associated with four specific upgrades to its OIS and emergency response systems designed to improve both its outage communication and storm response. Agreement 7 would establish a memorandum account to record the costs associated with the four upgrades and would allow PG&E to recover an amount up to $9 million in 2003, and $2.3 million for each of the years 2004, 2005 and 2006 (2003 nominal SAP dollars). The amount incurred in 2003 would be recoverable to the extent that PG&E's actual expenses in FERC Account 588 exceed 2003 GRC adopted FERC Account 588 revenue requirement by the amount that actual expenses exceed adopted revenue requirement up to the amounts in the memorandum account. For the expenses incurred in 2004, 2005, and 2006, the amounts would be recoverable up to the incremental amounts described above to the extent that PG&E's total electric O&M expenses exceed GRC adopted electric O&M revenue requirement. The four upgrades are 1) linking the OIS to mobile data terminals, 2) integrating three separate computer systems, 3) enhancing the mapping associations in OIS, and 4) programming to retain single customer outages in OIS. PG&E's request for funding of additional OIS upgrades warrants careful scrutiny given that PG&E was authorized $19.4 million in capital plus $3.6 million annually in expense for a new OIS as recently as its 1999 GRC.

TURN opposes PG&E/ORA Agreement 7. TURN recommends that the Commission disallow recovery of the incremental costs of two of the upgrades. TURN does not dispute that the projects are necessary but contends that these two projects should have been incorporated into the new OIS that was capitalized in 1999. In particular, TURN argues that the expenditures to integrate the three separate computer systems ($0.8 million in hardware and $3.25 million in expense) should be disallowed on the grounds that this integration should have been designed into the new CIS system that was capitalized in 1999. TURN also recommends that the Commission direct PG&E to amortize the costs of linking the OIS to the mobile data terminals and enhancing the mapping associations in OIS over three and five years, respectively. TURN believes that PG&E's request for $1 million in capital and $2.45 million in expense to remedy the treatment of single customer outages that are dropped off the system after 30 minutes should be disallowed for the same reasons.

TURN does not oppose PG&E's proposed $3.05 million expense on software upgrades for the mobile data terminal units, but suggests that this expense should be averaged over 3 years because it is a one-time expense that should minimize inaccuracies and reduce restoration time. Similarly, TURN does not oppose PG&E's request for $7.38 million in expense to enhance the mapping associations within OIS, but recommends that this expense be averaged over 5 years consistent with the expected length of this effort and the amount of projected expenditures per year. Aglet opposes Agreement 7 for another reason. Aglet believes that approval of Agreement 7 would constitute retroactive ratemaking by allowing PG&E to record costs incurred in 2003 in a memorandum account that was not approved until after the costs were recorded.

In response to TURN's claim that the expense on software for the mobile data terminals should be recovered over a three-year period, PG&E admits that the upgrade in the mobile data terminals is a one-time activity, but argues that as operational requirements change or are added, PG&E must continue to maintain the mobile data terminals, and upgrade the software. PG&E does not describe the nature of any ongoing activities or provide an estimate of the expense associated with any ongoing activities. Since PG&E admits that the software upgrade to link the mobile data terminals to the OIS is a one-time activity, we agree with TURN that PG&E's request should be averaged over three years. We modify Agreement 7 to require that the revenue requirement associated with upgrading the software to link the mobile data terminals to the OIS be amortized over three years. We note that PG&E has already revised its testimony to reduce the cost of enhancing the mapping associations within OIS and to amortize the cost over four years, and we approve that request.

In response to TURN's criticism that the integration project should have been built into the new OIS approved in 1999, PG&E states that it was not possible to integrate its three separate computer systems at that time due to limits in hardware and software that made the mapping rectification impossible. PG&E also states that it did not have a common SCADA platform available until 2002.

PG&E states that the OIS software that addresses single customer outages was originally configured such that during normal conditions, single customer outage calls or "tags" would be sent to the FAS to be individually handled. During storms, the process would change and PG&E's Operation Emergency Centers would manage these single customer outages via the OIS through an aged off report and personal callbacks to customers. ORA reports that in November 2002, the OIS software was upgraded.

PG&E states that it turned off the aging script at some point during the December 2002 storms. According to PG&E, this resulted in the OIS being "flooded" with single customer outages, slowing down the system and making the dispatcher's job more difficult. PG&E states that it took this step because when the system "aged off" the single customer outage, the recorded history of that outage was deleted by the system. This resulted in some customers calling to get an update on service restoration and being informed that PG&E had no record of their earlier call, as well as a delay in restoration of service.

PG&E states that the software configuration that caused the deletion of the single customer outages has since been resolved. PG&E also states that it intends to eliminate the "aged off" feature and that software will be developed to assist in better managing single customer outages more efficiently. PG&E states that at the time the OIS and the FAS were configured, PG&E's outage restoration process for single customer outages was handled most efficiently through the FAS rather than through OIS. However, PG&E has now determined, based on its experience during the December 2002 storms, that modifying OIS will be more effective than continuing to use FAS during major events. PG&E indicates that software modifications will be necessary to accomplish this upgrade, and provides an estimate of the cost associated with this upgrade, but does not provide any detail regarding the assumptions or criteria used in developing the cost estimate.

We do not believe that ratepayers should be required to fund the same OIS functionality twice. When the new OIS was funded in the 1999 GRC, the Commission justifiably anticipated that these system improvements would improve PG&E's outage response, including its response to single customer outages. PG&E states that it did not design the OIS system to handle single customer outages during storm conditions, and that the FAS was intended to deal with single customer outages. In response to TURN's suggestion that PG&E not be granted funding for these upgrades because they should have been incorporated into the OIS system that was funded beginning in 1999, PG&E simply states that the technology available in 1999 was not conducive to incorporating single customer outages in a system such as PG&E's OIS.

PG&E does not provide sufficient detail to allow us to evaluate the veracity of its claim, but we need not address whether such technology was available or not to find that PG&E's handling of single customer outages was unacceptable. When the FAS and new OIS were approved and funded in the 1996 and 1999 GRCs, PG&E designed the systems such that single customer outages during storms were managed through the FAS. During the December storms, that method was not successful. Customer outage calls were aged off and, following an upgrade to the OIS, deleted from the system as a result of an oversight on the part of PG&E. Had the outage reports not been deleted, presumably there would have been an accurate list from which the dispatchers would work to identify the problems, and restore service. While the nature of the storms made the problem more severe, it did not cause the problem.

In D.96-09-045, we found that meeting minimum system reliability measurements is not an adequate defense for failure to communicate with customers effectively during an emergency. Despite having completely overhauled its OIS system and spending at least $34 million of ratepayer funds in the process, not to mention the funds spent on the FAS, PG&E has still not managed to meet customer's expectations with respect to outage communications. It is unreasonable for PG&E to have allowed the system to function in such a manner as to allow single customer outages to go unrecorded and unresolved. We agree with TURN that PG&E should not be authorized to recover the cost associated with revising its treatment of single customer outages in this OIS since that functionality should have been incorporated into either the original OIS system or the FAS, both of which have already been fully funded by ratepayers. Therefore, we modify Agreement 7 to remove funding for the single customer outage issue.

In response to Aglet's claim that Agreement 7 would result in retroactive ratemaking, PG&E notes that in order to avoid the prohibition against retroactive ratemaking when impractical or inequitable circumstances arise, the Commission has authorized utilities to establish memorandum accounts in advance of the final decision that would determine the rates in questions and has issued "interim relief" decisions making the rates to be established in a later, final decision, effective as of a date earlier than the final decision. PG&E points out that the Commission adopted a similar process in the proceeding and that Conclusion of Law 2 in D.02-12-073 states: "the Commission intends that any changes to PG&E's gas and electric revenue requirements adopted in PG&E's TY 2003 GRC will become effective January 1, 2003." Ordering Paragraph 2 states "To the extent that, upon further order in PG&E's TY 2003 GRC, the Commission authorizes revisions to PG&E's authorize revenue requirements for the 2003 TY, such authorization may be made effective January 1, 2003.

PG&E states that its March 17, 2003 supplemental testimony supplemented not only the description of PG&E's operations contained in the original GRC application, but also the revenue requirement associated with such operations in response to the February 13, 2003 ACR. PG&E believes that the Commission's finding in D.02-12-073 that final revenue requirements adopted in this case would become effective as of January 1, 2003, applies equally to the revenue requirement requested in PG&E's supplemental testimony.

We agree. We understand Aglet's concern that the Commission cannot approve costs recorded by the utilities prior to an order or the adoption of a memorandum account that authorizes such recovery, but that is not what is contemplated here. The memorandum account proposed in Agreement 7 would be for the purpose of tracking the costs associated with specific upgrades to PG&E's OIS in excess of PG&E's recorded costs to allow the Commission to segregate the reliability-related costs adopted as part of PG&E's base revenue requirement from the costs associated with the OIS upgrades. In this instance, we are not tracking PG&E's actual 2003 expenditures for purposes of approving them separately from the PG&E's base revenue requirement; instead we are tracking the difference between authorized spending and actual spending to ensure that the cost of the OIS upgrades is not recoverable unless PG&E's actual expenses in FERC Account 588 exceed 2003 adopted FERC Account 588 revenue requirement by the amount that actual OIS upgrade expenses exceed adopted revenue requirement up to the amount in the memorandum account. Given the findings in D.02-12-073, and the purpose of the memorandum account, we concur that the memorandum account does not constitute retroactive ratemaking.

We modify Agreement 7 to approve the requested memorandum account and adjust the amount approved for recovery. Specifically, we adjust the amount eligible for recovery to reflect our findings that: 1) the cost for the mobile data terminals should be amortized over three years to reflect that it is a one-time project, and 2) the cost associated with addressing the single customer outages problem should be denied.

PG&E's initial request for the four OIS upgrades included an additional $3.050 million in expense to link OIS to the mobile data terminals, an additional $3.250 million in expense to integrate three computer systems, an additional $2.45 million in expense to retain single customer outages in OIS, and an additional $460,000 in expense in 2003 and $2.3 million in each of the years 2004, 2005, and 2006 (for a total project cost of $7.360) million for enhancing OIS mapping associations (all expressed in nominal 2003 SAP dollars). PG&E also initially requested $1.8 million in common utility plant.

Agreement 7 would provide for recovery of $9 million in expense in 2003 and $2.3 million in expense in 2004, 2005, and 2006 (nominal 2003 SAP dollars). We approve the requested memorandum account as an acceptable mechanism under which PG&E would be allowed to recover the costs of the OIS upgrades, but we will reduce PG&E's request to eliminate duplicative funding to address single customer outages. We also adjust the total to reflect that the expense associated with linking OIS to the mobile data terminals should be amortized over three years because it is a one-time project.

7.3 Other ORA/PG&E Agreements

a. Agreement 1 – Division Level Benchmarks

Agreement 1 requires PG&E to record and report reliability performance at the division level in addition to the system level. We find that ORA / PG&E Agreement 1 will resolve the concern expressed by ORA and Aglet about system level indices masking poor performance at the division level. Although

Agreement 1 provides that PG&E, in consultation with ORA, would develop the format for reporting division data, we direct that, at a minimum, the reporting requirements should be the same as those adopted in D.96-09-045 for system level reliability performance information. Therefore, the report filed annually pursuant to D.96-09-045 must include data detailing the division level average interruption frequency, division level average interruption duration, division level customer average interruption duration, and division level average momentary interruption frequency.

We find that Aglet's request that we adopt division level reliability measures as the primary measure of reliability performance is unnecessary at this time. Receiving division level data will provide us with additional information upon which to evaluate the PG&E's performance to determine whether such a designation is necessary. Furthermore, as we stated in D.96-09-045, meeting system performance levels is not a shield that can stave off liability for unreasonable performance at other levels or in other areas, such as outage communications.

b. Agreement 2 – Five–Year Average Benchmarks

Agreement 2 would require PG&E to investigate and report to the Commission when the adopted reliability performance measures vary by ten percent or more in any division and/or five percent or more at the system level from the five-year rolling average of reliability performance.

Agreement 2 is reasonable and should be adopted. We emphasize that approval of this Agreement does not in any way limit our ability to conduct other investigations or direct additional reports as we deem necessary.

Although Aglet argues that using rolling averages to measure performance tends to reduce the variability of performance metrics, we believe this

Agreement will assist in improving PG&E's performance by requiring automatic investigations and reporting if division-level performance decreases significantly.

c. Agreement 3 – Definition of Major Outage

In Agreement 3, PG&E and ORA recommend that the Commission initiate statewide workshops to address the definitions of Excludable Major Event, Major Outage, and Measured Event, as well as the restoration performance standard included in Standard 12 of G.O. 166. Agreement 3 also provides a list of topics to be considered in the workshops.

Agreement 3 stems from ORA's concern that PG&E and other utilities may not understand some of the requirements and definitions within D.96-09-045 and GO 166, or are interpreting them such that the Commission may not be receiving the uniform reliability data it desires. ORA recommended that the Commission establish a process to eliminate the various conflicts within D.96-09-045 and GO 166 and make the definitions uniform. ORA points out that while GO 166 clearly defines a Major Outage as a situation where 10% of PG&E's customer *simultaneously* experience an outage, D.96-09-045 defines an Excludable Major Event as an event that affects 10% of its customers (with no mention of *simultaneous* or *cumulative*) or 15% of its facilities. ORA also notes that while GO166 clearly defines how start and end times for a Measured Event are to be determined, D.96-09-045 does not define how start and end times should be determined for Excludable Major Events.

As we stated in D.96-09-045, uniform and measurable system standards are an important first step in defining reliability. The December 2002 storms were a significant event for PG&E, and from the perspective of the Commission, and consumers, clearly constituted a major event on PG&E's system even if they did not meet the technical definition of a major event. We agree with ORA that common sense dictates that either an event is major, subject to the standards set for performance during major events and excludable from any performance indices as an abnormal and infrequent event, or it is minor, in which case it should be considered part of a normal weather pattern, included in the performance indices, and subject to any performance standards applicable to normal weather. Currently, neither the Emergency Response Standards, nor the standards applicable to performance during normal conditions apply to the December 2002 storm event. In addition, we believe it is necessary to ensure a consistent understanding of the terms between or among utilities. We find that the workshop process proposed in Agreement 3 will assist in ensuring that the utilities consistently interpret and apply the requirements in D.96-09-045 and GO 166. Although it is currently extremely difficult to compare reliability performance between two or more utilities, a consistent interpretation and application of our standards and rules is a necessary first step in this direction. For these reasons, we will adopt Agreement 3.

d. Agreement 4 – Tap Fuse Installation Program

ORA's initial testimony supported PG&E's proposal to accelerate the installation of overhead lines fuses but opposed PG&E's request for additional funding. ORA argued that sufficient funding for this program is provided in PG&E's base TY 2003 GRC revenue requirement request.

Agreement 4 provides that PG&E will install as many additional sets of overhead fuses in 2003 to fully utilize the GRC requested amount of $5.4 million in MWC 49. Under Agreement 4, this is expected to result in the installation of no fewer than 2,000 overhead fuses in 2003.

Agreement 4 would result in the installation of additional fuses on an accelerated time frame, thereby improving system reliability. For these reasons, Agreement 4 should be approved.

e. Agreement 5 – Balancing Length of Outages

Agreement 5 states that PG&E will modify its current restoration practices to balance the length of outages with the number of customers affected and will keep ORA actively involved and informed in the process of developing this policy. PG&E's stated that, at the time of the December 2002 storms, its policy was to restore the largest number of customers first, irrespective of how long some customers were out. Due to the succession of storms that occurred in December 2002, customers in areas with small numbers of customers out of service as a result of the storm on Saturday who were due to the have their service restored on Monday or Tuesday were pushed to the back of the prioritization queue after another storm resulted in outages to a higher number of customers elsewhere on PG&E's system.

ORA argues that PG&E's restoration performance during the 2002 storms would have been more effective if PG&E had a clear policy to ensure that no customers are left without service for an inordinate amount of time. ORA's Consultants, Stone and Webster, note that there is no indication as to the longest interruption duration experienced by a PG&E customer; therefore, the magnitude of the problem is not clear. ORA's Consultants recommend that the Commission direct PG&E to track and report any customers that experienced outage durations longer than 24 hours in one-hour increments and request specific explanations for lengthy outages. ORA Consultants also recommend that the Commission consider an additional measure for restoration performance such as the number of customer that had an individual outage duration of more than 200% of the overall storm CAIDI or in excess of a particular time limit such as 24 hours.

Under Agreement 5, PG&E would modify its restoration policy to attempt to balance the outage duration with the number of customers. PG&E states that it will have employees dedicated to small numbers of customers to restore them if their service has been out for an inordinate amount of time. Agreement 5 does not address the latter two recommendations by ORA's Consultants, or define the amount of time considered "inordinate," but it does provide for active involvement by ORA in the development of the policy.

We will approve Agreement 5 because it will reduce the potential for customers experiencing unusually long outages in the future by balancing the length of outages with the numbers of customers affected. In addition, although the latter two recommendations offered by ORA's Consultants are not included in Agreement 5, we find that these recommendations have merit and should be considered as well. We direct PG&E to track and report any customers that experienced outage durations longer than 24 hours in one-hour increments and provide specific explanations for outages longer than 48 hours. We also direct that, during the workshops to be conducted pursuant to PG&E/ORA Agreement 3, parties should develop an additional measure for restoration performance, such as the number of customers that had an individual outage duration of more than 200% of the overall storm CAIDI or in excess of a particular time limit, such as 24 hours.

f. Agreements 8 and 9

According to Agreement 8, PG&E will monitor and report to ORA on its implementation of the existing measures in its action plans (the improvement initiatives) and well as its investigations into additional technical measures to improve the accuracy of its VRU systems and potential methods to prevent its Safety Net line from being overburdened during high-call volume emergencies. Under Agreement 9 PG&E and ORA agree on a mutual approach to monitoring and reporting to ORA on any needed adjustments to its OIS, Customer Information System, FAS, VRU, and all customer interface and response systems that would aid PG&E in making resource deployments to address outages.

Agreements 8 and 9 respond to recommendations made by ORA. We recognize that ORA's testimony did not request specific action from PG&E or the Commission on these issues, and only requested that PG&E take its concerns into consideration. No other party commented on Agreements 8 and 9. Agreements 8 and 9 will allow PG&E and ORA to work cooperatively to identify potential improvements to PG&E's OIS, Customer Information System, FAS, and VRU and should be approved.

7.4 Performance Incentive Mechanisms and Metrics

a. Reliability Mechanisms

Various reliability incentive mechanisms were proposed for PG&E that would establish specific performance targets, provide for performance incentive payments and penalties, and include an incremental annual revenue requirement. Subsequent to the evidentiary hearings in this phase of the proceeding, CUE and PG&E filed joint testimony recommending approval of a modified version of the original CUE proposal as described in Section 6.1 above. To summarize, the PG&E / CUE proposal include the following elements:

- The term of the proposal is six years, 2004 through 2009.
- The performance metrics are the SAIDI and the SAIFI;
- The SAIDI target in terms of minutes per customer, by year, is: 171, 164, 158, 151,151,151;

- The SAIFI target in terms of interruptions per customer, by year is 1.42, 1.33, 1.24, 1.16, 1.16, 1.16;

- The maximum annual reward and penalty is $31.6 million for SAIDI and $10 million for SAIFI;

- The Deadband is 4.2 minutes per year for SAIDI and 0.05 outages per year for SAIFI on either side of the target;

- The Liveband is 15.8 minutes per year for SAIDI and 0.10 outages per year for SAIFI, for livebands on each side of the targets; and

- An Additional Revenue Requirement of $27 million annually for six years to be used for reliability improvement expenditures, subject to balancing account treatment;

- Any revenues not spent by PG&E in 2004, 2005, and 2006 would be carried over to the following years, up to 2007. Unspent revenues at the end of each year 2007, 2008, 2009 would be credited back to ratepayers at the end of each year.

CUE believes that PG&E's reliability needs improvement and argues that by combining incremental revenue with an incentive mechanism, the PG&E/CUE proposal would encourage improvements in PG&E's reliability, and ensure that PG&E's customers do not pay for improved reliability unless they get it. CUE compares PG&E's performance measures to SCE's and SDG&E's performance measures and suggests that PG&E's performance is much worse than the other two utilities. CUE also asserts that reliability should be improved because PG&E's average restoration time, as measured by the CAIDI, is increasing. CUE compares PG&E's current field staffing levels with prior PG&E field staffing levels and argues that decreases in customers per electric field personnel correlate to increases in outage restoration time. CUE suggests that PG&E be given financial incentives to maintain and improve reliability structured like the incentives already in place for SCE and SDG&E.

We will approve some aspects of the incentive mechanism as proposed in the joint proposal by CUE/PG&E but decline other aspects of the join proposal. We make some modifications as described below. We believe that this approach best balances our desire to encourage improvements in system reliability in addition to those the company intents to pursue through its adopted revenue requirement while providing the financial incentive to do so. Further, with the modifications as described below, we establish our intention that PG&E have a set of conventional statements about our expectations to continually improve reliability. We are interested in encouraging further improvements in the safety and quality of PG&E's system reliability as adopted in PG&E's revenue requirement in D.04-05-055. The incentive mechanism we establish in today's order provides for an opportunity to improve on the reliability metrics. We reiterate our expectation that PG&E's managers will give the proper attention to this area of performance. We note that the commission has various regulatory mechanisms for addressing deviations from expected levels of service. Most include after-the-fact performance reviews such as penalties, disallowances, and ratemaking enhancements. A properly structured incentive program that is layered on top of cost-of-service ratemaking as we intend to practice it can be a targeted regulatory mechanism that promotes improvements and discourages retrogressions in system reliability and performance. However, we share parties' concerns that the Joint Proposal may overly burden ratepayers with rewards to the company for improvements it expects to achieve absent the Joint Proposal. As such, we make further modifications to refine the incentive mechanism proposed by PG&E/CUE to properly overlay it to a cost of service regime.

CUE places much emphasis on the fact that PG&E's performance measures appear worse than the other utilities. However, all of the parties in this case acknowledge that it is difficult to compare indices between and among utilities due to significant differences in system design, geography, weather patterns, and measurement methods. As PG&E points out, even CUE has previously testified that an individual utility's "numbers can't be meaningfully compared to other utilities because other utilities do not use the same method of calculating SAIDI (and also because of weather and geographical differences."[23] PG&E also notes that CUE previously characterized SCE's attempt to compare its SAIDI performance to 43 other utilities as "not meaningful."[24] PG&E states that as measured by the absolute values of SAIDI and SAIFI, without further analysis or understanding of the differences in outage reporting methods, CUE's assertion that PG&E's performance is worse is technically accurate, but not meaningful. PG&E states that it calculated PG&E SAIDI and SAIFI values using its understanding of the methodology used by SCE to measure outage duration and frequency and found that using SCE's methodology, PG&E's SAIDI value for the last five years would improve (decrease) by 21 percent, and PG&E's average SAIFI value for the same time period would improve (decrease) by 12 percent. Although PG&E is not certain that it exactly mimicked SCE's methodology, it is certain the measurement method used affects the results.[25] In addition, CUE and

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[23] Exhibit 18-B, page 2-12, lines 17-19.

[24] Exhibit 18-B, page 2-12, lines 19-21.

[25] An IEEE paper cited by PG&E supports the proposition that different measurement methodologies make comparison of results between / among utilities difficult. "A Nationwide Survey of Recorded Information Used for Calculating Distribution Reliability Indices"

PG&E admit that SCE's PBR mechanism has a different definition of an excluded event than PG&E uses.

Based simply on the annual SAIDI, SAIFI and MAIFI performance reported by PG&E, we cannot find that the mere presence of a difference between PG&E's performance results and SCE's or SDG&E's performance results justifies a change in performance standards. PG&E's service may indeed be less reliable that the other two utilities, or it may simply appear less reliable due to system differences or different methods used to calculate SAIDI and SAIFI.

CUE also states that it compared PG&E's SAIDI, SAIFI, and CAIDI data to the SAIDI, SAIFI and CAIDI data for six New York State utilities, the City of Redding, Pacificorp, and Portland General Electric and, in each case, found that PG&E's results reflected lower reliability. Again, however, we cannot effectively compare the summary reliability data provided for these other utilities without also comparing any differences in measurement techniques, weather, geography, and system size and design. CUE did not provide the information necessary to make such a comparison. As PG&E notes, although individual utilities may have certain similarities, other differences may exist that would explain the differing results. We agree with PG&E that inter-utility comparisons are of limited value because different utilities measure different things, serve different customers mixes, and experience different weather. Based on the record in this proceeding, using the performance indices alone, we cannot find, as CUE claims, that PG&E's service is significantly worse than SDG&E's and SCE's, due to the different methods of calculating the inputs that the indices are derived from.

As we have found in previous decisions, it is not particularly useful to compare utilities with different customer counts, different geography and weather patterns, different system configurations, not to mention different methods of calculating SAIDI, SAIFI, and MAIFI. Given these factors, it is extremely unlikely that any two utilities would ever achieve similar performance results; therefore, we are reluctant to place much faith in such comparisons. We believe that the more appropriate comparison to make is a comparison between PG&E's historical performance and its current performance.

In D.00-02-046 we stated that PG&E's performance during the 1996-1998 period was reasonable, consistent with historically accepted levels of service. In this phase of the proceeding, we are conducting a high level review of PG&E's performance during the period from 1999 through 2002, including, but not limited to, the December 2002 storms. We find that PG&E's overall reliability performance during normal conditions, as measured by SAIDI, SAIFI, and MAIFI[26] performance reported in PG&E's annual reliability reports, has either improved relative to 1996-1998 levels or has remained consistent with 1996-1998 levels.

The data provided in Table 2-4 and Table 2-5 of PG&E's Exhibit 13 on the number of customer interruptions demonstrates an increase in reliability compared to the 1996-1998 period referred to in D.00-02-046. PG&E's three-year SAIFI average (excluding major events) decreased 13 percent from 1.66 during 1996 through 1998, down to 1.44 from 1999 through 2001. PG&E's four-year SAIFI average from 1999-2002 was 1.36. PG&E's 2002 SAIFI average was even lower, at 1.11.

Including major events, the trend is the same. PG&E's three-year SAIFI average from 1996 through 1998 was 2.10, decreasing to 1.48 in 1999 through 2001. PG&E's four-year SAIFI average from 1999-2002 was 1.53.

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[26] Exhibit 500, page 8, Table DM-1. PG&E cautions that changes in measurement techniques over time make it difficult to rely on pre-1999 MAIFI data.

The SAIDI averages have fluctuated from year to year and do not demonstrate a trend in either direction. PG&E's three-year SAIDI average (excluding major events) was 173.3 from 1996 through 1998, while PG&E's three-year SAIDI average from 1999 through 2001 was 178.8. PG&E's four-year SAIDI average from 1999-2002 was 168.9. Including major events, PG&E's three-year SAIDI average from 1996-1998 is 278.4, while the three year average from 1999-2001 is 191.6. PG&E's four-year SAIDI average including major events is 239.2.

PG&E's CAIDI increased from 103.67 during 1996-1998 to 124.25 from 1999-2002.

A key assumption underlying the PG&E / CUE reliability proposal is that the Commission and PG&E's customers desire additional reliability above and beyond the levels already established in previous Commission decisions. PG&E and CUE state that the public response to the December 2002 storms is evidence that customers desire additional reliability. PG&E and CUE also view the issuance of the ACR as an indication that the Commission desires an improved level of service to customers. Other than that, the record is very limited on PG&E's customer's desires.

Although PG&E and CUE argue that the values of service in G12003 show that PG&E customers are willing to pay for additional reliability, we reject this argument for the same reasons we reject ORA / PG&E Agreement 6; we do not base our analysis of whether a performance incentive mechanism is needed on the outdated VOS information. We also reject CUE's claim that the billions of dollars of Department of Water Resources contracts executed by the State of California in 2001 were directed toward improving SAIDI and can be used as a proxy for current customer value of service data. Therefore, we must evaluate the reliability incentive mechanisms proposed on a different basis.

Another major premise of the PG&E / CUE proposal (as well as the original CUE proposal) is that substantial increases in funding are necessary for PG&E to improve reliability performance. PG&E argues that in order to significantly improve reliability, it requires additional revenues over its forecast in the base GRC case. PG&E states it has requested funding in the GRC for only one program intended to improve reliability: the overhead tap fuse installation program contained within MWC 49, which is the subject of Agreement 4 with ORA. PG&E asserts that the forecasts associated with the other MWCs are intended to maintain the adequate service level identified in D.00-02-046 and that in order to have an opportunity to meet the targets in the PG&E / CUE incentive mechanism, PG&E requires additional revenues.

ORA, TURN and Aglet argue that there is no evidence that increasing reliability requires additional funding beyond the levels requested by PG&E in its base GRC. In its Opening Brief, TURN compares the PG&E / CUE performance targets with PG&E's expected reliability performance absent any new funding. TURN's forecast assumes the base level of future SAIDI performance is the 1998-2002 SAIDI average of 171.1. TURN then calculates the expected impact of PG&E's overhead tap fuse installation program on SAIDI and SAIFI levels. According to PG&E, the overhead tap fuse program is expected to result in a total savings equal to 10% of the 1997-2000 SAIDI average or 16.7 minutes of improvement in SAIDI. (10% of 166.6 minutes equals 16.7).[27] The program began in 2002, and according to PG&E, should yield benefits of 2 % improvement per year, or 3.33 minutes in SAIDI per year over the course of the

[27] ORA Exhibit 917, p.1 and PG&E Exhibit 13, p. 2-17

five-year program.[28] TURN then forecasts SAIFI using PG&E witness Blastic's estimate that the tap program would result in a reduction of 0.1 outages by 2007.[29] The resulting TURN forecast is shown in the table below.

[28] TURN argues this forecast is a conservative estimate of PG&E's future SAIFI because it does not consider any additional improvements beyond those connected to the fuse program, it does not assume continuation of 2002 performance, and it assumes no additional reliability improvements in 2007 through 2009 associated with funding in PG&E's next GRC.

[29] RT vol. 26, p 3039.

TABLE 5

	TURN Estimate of Expected PG&E SAIDI Performance	**PG&E/CUE Proposal SAIDI Performance TARGET**	**TURN Estimate of Expected PG&E SAIFI Performance**	**PG&E/CUE Proposal SAIFI Performance TARGET**
2002	139.2 (Actual PG&E Performance)[30]		1.11 (Actual PG&E Performance)	
2003	167.8		1.2-1.3	
2004	164.5	171	1.2-1.3	1.42
2005	161.1	164	1.2-1.3	1.33
2006	157.8	158	1.2-1.3	1.24
2007	154.5	151	1.1-1.2	1.16.
2008	154.5	151	1.1-1.2	1.16
2009	154.5	151	1.1-1.2	1.16

ORA offers a similar comparison starting with the SAIDI average prior to the implementation of the tap fuse program. Using 166.6 minutes as the starting SAIDI value (the average SAIDI value from 1997-2000, excluding major events), and assuming PG&E reaches its goal of a two percent reduction annually in SAIDI to reach a 10 percent total reduction, ORA calculates that PG&E would expect to achieve a SAIDI value of approximately 150 minutes in 2006. Therefore, without any incremental revenue or an incentive mechanism, PG&E would surpass the proposal's 2006 performance target of 158 minutes by approximately 8 minutes.

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30 PG&E Exhibit 13, p. 2-17.

According to ORA's calculation, under the PG&E / CUE proposal, PG&E would receive $81 million in incremental revenue from 2004 through 2006 ($27 million X 3 years) and collect a total reward of $65.2 million ($28.8 million in 2004, $20.2 million in 2005 and $16.2 million in 2006) by meeting a SAIDI target that the company intends to meet absent the proposal.

Taking even more data into consideration by using the five-year average of annual SAIDI values from 1997-2001, ORA calculates that PG&E would expect to achieve a SAIDI of 158.1 minutes in 2006, equal to the 2006 target in the CUE / PG&E agreement.[31] In this case, the PG&E / CUE proposal would provide PG&E $81 million in incremental revenue from 2004 to 2006 for achieving a target that it should achieve under its current plans without additional revenue.

As several parties have pointed out, with respect to the expected levels of improvement associated with the tap fuse installation program, PG&E witness Blastic's testimony in support of the joint PG&E / CUE proposal is inconsistent with the prior testimony of PG&E witness Camara. As noted above, while witness Camara's prepared testimony, written response to ORA's data request, and oral testimony in response to cross-examination questions describe the tap fuse installation program as a five-year program designed to result in a 2% improvement in SAIDI per year and a 10% reduction in SAIDI over the five year program, PG&E's Opening Brief states that the length of the program was modified by Witness Blastic on the stand and it is now expected to be a seven year program. PG&E further states that the expected reliability benefit of this program is now approximately a two minutes reduction in SAIDI per year,

[31] The five year average of SAIDI from 1997-2001 is 175.6.

instead of a 2% reduction in SAIDI per year.[32] PG&E does not provide a rationale or any supporting evidence for this change.

In evaluating the conflicting testimony, we give more weight to the estimate provided in PG&E's prepared testimony, primarily because the original estimate was provided by witness Camara in two separate documents, PG&E's prepared testimony and in a response to a data request from ORA. PG&E had an opportunity to review and modify its response through its rebuttal testimony and did not do so. Finally, we note that since the PG&E/ORA Agreement 5 results in a lower tap fuse cost estimate and a corresponding increase in the number of annual fuse installations, the reliability benefits should be expected to exceed the original estimate, not decrease it.

ORA also notes, as does TURN, that PG&E fails to account for any potential reliability improvements associated with MWC 08 and the improvement initiatives identified by PG&E in response to the outage communications problems encountered during the December 2002 storms. Despite PG&E's argument that its forecasts in its other MWCs are not adequate to provide measurable improvements in reliability, a close review of PG&E's testimony shows that it expects several activities to affect reliability.

PG&E states that the main activities it relies upon to directly improve reliability are contained in the "Dependability" program. The Dependability program includes Capital MWCs 08, 09, and 49, and Expense MWC HX. Although MWC 49 is the only category for which PG&E calculates specific reliability improvements, PG&E acknowledges that there are several other areas that directly affect reliability as well.

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[32] RT 3002-3003.

As TURN points out, PG&E's TY 2003 request in MWCs 08, 09, 49 and HX is $19.56 million (capital and expense combined). This represents a 43% increase over 2001 expenditures in these MWCs. In addition, PG&E's witness Bhattacharya admits that, assuming equivalent weather, granting PG&E's total request in the Dependability MWCs would lead to performance that is consistent with 2002 performance, and most likely better.[33]

Witness Bhattacharya also states that "the vast majority of PG&E's expenditures are linked to reliability, even though reliability is not the main driver for the work."[34] As an example, witness Bhattacharya explains that distribution capacity work can improve reliability by providing additional capability for use during emergency switching, or by providing additional circuit ties for improved restoration switching. Witness Bhattacharya also reports that customer connection work can improve reliability as crews perform minor corrective maintenance in conjunction with installing facilities to serve new customers. We find that PG&E's expenditures in those areas should be expected to maintain and potentially improve reliability, whether measured by SAIFI, as in the case of pole replacements, or SAIDI, as in the case of PG&E's OIS improvements.

We also find that the improvements that PG&E intends to make to its OIS and its call center performance are likely to improve PG&E's reliability performance as well. For example, enhancing the mapping associations within the OIS so that smaller portions of PG&E's circuitry can be pinpointed may reduce outage duration by providing PG&E with more accurate information

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[33] RT 182.

[34] Exhibit 13, p. 1-7.

regarding damaged facilities and the repair personnel and equipment necessary. More accurate information regarding the number of customers affected by outages will allow PG&E to focus its repair efforts. Similarly, utilizing mobile data terminals to accelerate the input of outage causes and damage assessment information to the Operations Emergency Centers should also have a positive effect on outage duration. Integrating three of the company's internal information control systems may also have a positive effect on reliability by reducing the number of entries required by a system operator.

Comparing TURN's estimated PG&E performance without any additional funding beyond that requested in PG&E's GRC application to the PG&E/CUE target performance levels, we find that, if it pursues the programs for which it sought funding in its application, PG&E will be able to meet and exceed the target levels without incremental funding or incentives. Furthermore, since the joint PG&E/CUE proposal contains deadbands of 4.2 minutes per year for SAIDI and .20 outages per year for SAIFI, it is highly likely that PG&E will receive incentive payments each year for its performance even without any additional effort on the part of PG&E.

ORA, TURN and Aglet also express concern that PG&E and CUE have offered no indication of the costs of reliability improvement apart from the tap fuse installation program. When asked to justify the need for an additional $27 million annual revenue requirement to achieve the target levels, CUE admitted that the number was not based on the estimated cost to PG&E to achieve the levels, because CUE "does not know what the cost might be." CUE also states that "there is no analysis of the precise amount. It could be more, it could be less."[35]

Given the absence of any evidence supporting the need for this increment of funds, ORA, TURN and Aglet argue that the Commission should reject the proposed incentive funding mechanism. We agree. Given the discussion above, we find insufficient analytical support for the requested funding of $27 million per year for six years to achieve the reliability targets. Neither CUE nor PG&E has provided any analysis to support this amount of incremental funding other than claiming that the $27 million somehow equates to the value of the benefits to ratepayers if PG&E meets the new performance targets. We find this unpersuasive, particularly in light of the detailed analysis provided by PG&E in support of its tap fuse installation program. As such, we decline to adopt the portion of the CUE/PG&E Joint Proposal which authorizes additional annual revenue requirement for improvements in reliability metrics.

While PG&E forecasts $5.4 million per year for five years to fund a tap fuse installation program designed to achieve a 16.7 minute reduction in SAIDI over five years, the PG&E/CUE proposal would have us approve an incremental revenue requirement of $27 million annually for six years to allow PG&E to meet reliability performance targets that reflect, at best, a 20 minute reduction in SAIDI when compared to the 1997-2000 performance. Compared to PG&E's SAIDI performance in 2002, the PG&E/CUE proposal would have ratepayers funding an incremental revenue requirement of $27 million per year to meet performance targets that reflect worse performance than that achieved in 2002.

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[35] RT 3060: 8-9.

CUE asks us to find that the rate impact of the PG&E/CUE proposal is minimal. We cannot make such a finding. As TURN points out, the PG&E/CUE assertion that the maximum rate impact of its reliability incentive mechanism will be less than 0.08 cents per kWh is based on the assumption that costs will be allocated on an equal cents per kilowatt hour basis across all customer classes. TURN points out that this assumption is not consistent with the Commission's past cost allocation decisions. TURN calculates that a $68 million increase represents a 15% increase compared to PG&E's electronic distribution revenue requirement request of $447 million and could result in a total average distribution rate increase of almost 23%.

Furthermore, as Aglet points out, the PG&E/CUE proposal's claim that there is a direct relationship between additional revenues and reliability improvements is disputed by PG&E's prepared testimony that asserted no linkage between spending and specific reliability improvements.

Another critical assumption of the CUE/PG&E proposal is that the $27.5 million allocated annually to the Reliability Improvement Memorandum Account (RIMA) would facilitate initiatives that are: 1) incremental and 2) spent on reliability related improvements. According to the PG&E/CUE joint testimony, the RIMA would be a one-way balancing account designed to separately identify amounts adopted in PG&E's TY 2003 GRC and the incremental expenditures incurred in planning and implementing distribution system reliability improvement activities funded by the $27 million annual incremental revenue. Although PG&E claims that the proposal does not grant PG&E an "additional revenue requirement," because recovery is not guaranteed, the authorized $27 million in additional revenue will be credited to the RIMA each year and any potential refunds would not occur until after the year 2007 at the earliest.

The RIMA would record incremental distribution expense expenditures associated with MWCs HX, NEW 1 and NEW 2. Although PG&E would be required to demonstrate expenditures equal to GRC-approved base levels in these three accounts, the proposal does not guarantee that RIMA projects would not supplant the funding represented by base GRC levels, because MWC NEW 1 and MWC NEW 2 do not currently exist and there would be no GRC approved base level of expenditures for these two MWCs. PG&E admits that since these two MWCs do not exist, there would be no requirement that these two MWCs be fully utilized in order to identify expenses as "incremental" to approved base levels. Furthermore, CUE admits that the burden would be on other parties to show that expenditures were not "incremental" and that if PG&E "managed to fool you … and convinced the Commission that it was an incremental expense, then it would be allowed," i.e. PG&E would be allowed to use incentive funds for non-incremental expenses.[36]

While the RIMA would not be triggered until PG&E exceeds its GRC-approved base level spending forecast for MWC HX activities, it does not limit RIMA eligibility to activities that would otherwise be classified in MWC HX. This is also true for capital expenditures, if PG&E exceeds the GRC-approved base level spending forecasts for MWCs 08, 09, and 49, any other "reliability" expenditure could be classified as incremental regardless of whether the approved funding in the MWC normally applicable to that activity has been fully utilized. We agree with TURN and Aglet that this could result in PG&E redirecting existing resources towards reliability improvements in order to

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[36] RT 454.

achieve incentives or simply reclassifying existing activities as reliability programs in order to access the additional $27 million.

Moreover, PG&E and CUE admit that any challenge to expenditures claimed to be reliability related would require affirmative review and action by other parties, like ORA and TURN. CUE admits that "if [the other parties] just sit there and do nothing and everybody sits there and does nothing then presumably it would get approved."[37] Since there is neither a definition of reliability related activities nor a definition of expenditures that are specifically ineligible for inclusion in this account, this burden would be extremely hard to meet. PG&E's witnesses acknowledge that many costs can be classified as "reliability related" and that it is hard to determine the difference between a reliability program and a non-reliability program.

Unlike the specific programs included in the vegetation management program adopted in PG&E's TY 1999 GRC, the definition of reliability programs to be included in the RIMA is vague, as a result, to the extent that PG&E manages to reclassify existing efforts from other MWCs as reliability programs, there remains the potential for capital expenditures to be shifted from other MWCs into the RIMA, rather than resulting in new activities designed to improve reliability. We agree with TURN that the RIMA would allow for the reallocation of program budgets to create the appearance of additional, reliability-related activities while permitting PG&E to substitute RIMA funds for base GRC funding levels.

Aglet is also concerned that the incentive mechanism would motivate PG&E to shift resources away from activities whose costs the Commission has

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[37] RT 449, 457-58.

allowed in rates in order to achieve incentive rewards. ORA shares Aglet's concern, and notes that through distribution rates, ratepayers already pay PG&E a rate of return on its electric distribution plant investment, which presumably provides customer with highly reliable service consistent with statutory requirements. Since PG&E admits that a general feature of incentive mechanisms is that they can result in reallocation or redirection of resources from one area of a firm's operations toward the area that is the subject of the incentive, we agree with ORA and Aglet that the CUE/PG&E proposal has the potential to force customers to pay for the same level of service three times, first through the base revenue requirement, a second time through the incremental revenue requirement and a third time through incentive payments.

ORA and Aglet also expresses concern that if the Commission approves that PG&E/CUE proposal, it will be difficult to accurately measure the reliability improvements that would have occurred in the absence of the program, causing uncertainty in how to evaluate any reliability-related revenue requirement requests in PG&E's next GRC. The PG&E/CUE proposal would lock the Commission into a long-term commitment beyond the term of the current GRC cycle. With no requirement that PG&E identify particular projects or programs with associated reliability improvements, it will be difficult to assess the reasonableness of PG&E's revenue requirement request in the next GRC.

We appreciate the concerns raised by Aglet, ORA and TURN with respect to the Joint Proposal. However, we find there is value in adopting some aspects of the Joint Proposal as a means to encourage further improvements in system reliability on top of those the company expects to achieve through the projects identified in its revenue requirement request. Performance incentives such as those at issue here are a relatively recent regulatory phenomenon for California electric utilities. They were first adopted in connection with the Commission's

1990's experimentation with PBR as an alternative to conventional cost-of-service ratemaking. For example, in 1994, in D.94-08-023, the Commission adopted a PBR proposal for SDG&E that included performance incentives to "reward or penalize the utility's ability to control employee safety, system reliability, and customer satisfaction." (55 CPUC 2d 592, 633.) The Commission adopted performance incentives in connection with PBR mechanisms for SCE in 1996 (D.96-09-092; 68 CPUC 2d 275) and for SoCalGas in 1997 (D.97-07-054; 73 CPUC 2d 469). In D.99-09-030 the Commission adopted a second-generation PBR for SDG&E that included performance incentives. In adopting SCE's PBR, the Commission stated the following:

> Thus, we see PBR as emulating the competitive process to encourage utility management to make decisions which resemble an efficient or competitive outcome. An efficient utility will control rates which benefits ratepayers. However, we want to ensure fairness to ratepayers, employees and shareholders in the PBR process. This requires balancing potentially conflicting interests. The utility can increase short run profits through reducing variable costs, but without revenue sharing such cost reductions will not lower rates. Moreover, such reductions not only can affect staff immediately but the service quality impact may only appear much later. [¶] In this PBR for Edison, we balance these interests by requiring a progressive sharing of net revenue between shareholders and ratepayers and by having both the productivity and service quality measures increase over the duration of the PBR. (68 CPUC 2d 275, 290.)
>
> In adopting the SoCalGas PBR, the Commission observed that the utility had proposed a service quality mechanism "[i]n order to ensure that SoCal's focus on increased productivity through cost reductions does not have a deleterious effect upon the quality of service . . . during the period when the PBR rates are in effect." (73 CPUC 2d 469, 490.)

We have previously rejected performance-based ratemaking for energy utilities in favor a transparent regime of cost-based ratemaking. Consequently it may appear anomalous to borrow targeted performance incentives from the obsolete PBR regime. Performance incentives mechanisms may add complexity to regulation and ratemaking. They can be controversial, as evidenced by the extent of litigation and lack of agreement among the parties over how to construct them, even after two of the parties reached a settlement agreement. Moreover, even if they are reasonably calculated to promote a specific regulatory objective, performance incentives could work at cross-purposes with other regulatory objectives or have other unintended consequences. For example, incentives that are intended to improve reliability by reducing the number of circuit interruptions might be inappropriate, even if effective, if they added unduly to ratepayer costs. While some argue that improperly constructed incentives are worse than having none, others point out that such incentives can lead managers to make non-optimal resource allocation decisions.

Nevertheless, we will approve a set of targeted performance incentives that provide both rewards and penalties because they provide a more responsive approach to deviations in service adequacy and quality than our other ratemaking mechanisms. As noted above, they were adopted to mitigate the potentially deleterious effects that the efficiency gains sought through PBR could have on service quality, including reliability, and on safety. They can be carefully adapted to the cost-of-service regime and enhance our ability to regulate in the public interest, providing both financial incentives to guide utility activities and an early warning of longer-term trends that we can use to guide more intrusive regulatory interventions such as complaints and investigations. They represent a calibration, not a contradiction, of our cost-of-service principles.

In the cost-of-service regime we attempt to determine the reasonable costs of adequate service and establish rates that cover those costs, including a reasonable profit. This entails describing the public's expectations about service quality, including performance benchmarks and standards, and providing revenues sufficient to pay for those service levels. In the cost of service regime we aspire to transparent accountability for revenues and costs, so that we can determine both the causes of failure to meet expectations and the resources needed to provide incremental improvements, if necessary.

We will consider whether the proposed performance incentives are necessary for achieving one or more of our regulatory objectives and are likely to be cost-effective; we do not believe that performance incentives should be adopted solely on the basis of their mere consistency with a particular objective. Since rates set through our conventional approach to ratemaking are intended to provide the funding required to meet the regulatory objectives of safe and reliable service, we must ask why the utility needs the possibility of additional ratepayer funding, or threat of reduced funding, to get the utility to do what it is already funded and expected to do. The burden is on the proponents of performance incentives to prove they are necessary, cost-effective, and otherwise reasonable.

Performance incentives can be structured to carefully layer on top of a rigorous cost-of-service approach to T&D operation, maintenance and capital spending . The performance measures we adopt today accurately reflect current levels of utility performance in service reliability as measured by the frequency and duration of outage events (SAIDI and SAIFI). However, we find that further refinements to the proposed metrics are warranted. Deviations from these levels of performance are rewarded or punished, financially, as the deviations occur.

We would expect that this focus on results measured more frequently than the General Rate Case permits will help PG&E sustain its efforts.

In proposing performance incentives for system reliability the utility exposes itself to the inference that it may not perform reasonably in those areas even with the funding to do so. However, we find that the evidence supports the proposition that PG&E has sufficient incentive to provide "adequate" service through the cost-based rates we have authorized in D.04-05-055.

The performance incentives proposed by PG&E/CUE are, at most, incremental to existing incentives to perform well. Further, a number of negative business consequences could ensue including threats of lawsuits; higher insurance premiums; bad publicity; loss of goodwill and other forms of corporate prestige; and, in the most extreme cases, loss of franchise or municipal takeover.

Even in the absence of additional incentives such as those under consideration, we can expect that PG&E's managers will pay a great deal of attention to the company's performance in each of the areas for which incentives have been proposed.

Ratemaking consequences attached to deviations from the established benchmarks should reinforce those incentives and lead to improved performance, accurately measured.

We are not pursuaded by PG&E and CUE that the proposed RIMA adequately prevents PG&E from shifting funding from other areas to dependability in order to access the $27 million, nor does it provide protection against PG&E spending the $27 million on projects that do not result in increased reliability. The risk is simply too high that customers will end up paying twice for the same reliability improvements as a result of the proposed incentive mechanism.

The original CUE proposal is not justified because it would burden ratepayers with an additional $72 million annual revenue requirement and up to $145 million in incentive payments without demonstrating that the reliability target is appropriate, that customers are willing to pay for that level of reliability, or that $72.5 million is the correct price to pay to achieve that level of reliability.

PG&E's alternative proposal also fails because it would result in PG&E receiving incentive payments for maintaining the average level of service it has achieved over the last five years, as measured by SAIDI and SAIFI. PG&E provides no justification as to why customers should pay more to fund incentive payments for service that the Commission has already deemed to be the reasonably expected level of service covered by base rates.

As we stated in D.00-02-046, a complete analysis of the reasonableness of expenditures to improve the integrated utility system would include an assessment of how the cost of improvement alternatives is weighed against the improvements in utility system infrastructure. Value of service analysis is the recognized tool by which such weighing takes place. As discussed above, we find that the existing value of service data is too dated to rely on. While customers were frustrated by PG&E's performance during the December 2002 storms, and may prefer improved performance, they may not be willing to bear the additional rate increases associated with an increase in reliability performance. Given the absence of relevant value of service studies or sufficient evidence demonstrating that ratepayers prefer, and are willing to pay for, increased reliability generally, we are reluctant to approve the increases in funding associated with the PG&E/CUE proposal. Furthermore, since the incentive mechanism is based on system-wide metrics, there is no guarantee that those customers facing the worst performance would see increased reliability.

Instead, we adopt a reliability incentive mechanism as shown in the following table. We decline to adopt a mechanism whose length exceeds the TY2003 cycle and we modify the target metrics as follows:

TABLE 6

	SAIDI excluding Major Events	**SAIFI excluding Major Events**
2005	165	1.40
2006	161	1.33
2007	157	1.24
Deadbands	10 min / yr	0.10 outages / yr
Livebands	15.8 min / yr	0.15 outages / yr
Max Annual Reward / Penalty	$31.6 million	$10 million

b. Employee Safety Mechanisms

CUE proposes that the Commission adopt an employee safety mechanism to prevent PG&E from cutting corners on safety in order to save money. CUE argues that an employee safety mechanism is particularly important in the context of reliability performance incentives, where there is a direct financial incentive to restore service as quickly as possible. CUE recommends that the mechanism be based on the OSHA recordables frequency rate, with the benchmark set at 5.42, PG&E's most recently attained safety level.

PG&E opposes CUE's recommendation, arguing that PG&E already has a comprehensive program to promote safety and health and manage the incidence of injury and illness in the workplace. PG&E states that its program has yielded continued and sustained improvement in safety and health in recent years. PG&E also argues that changes in the OSHA regulations for reporting injury or illness that took effect on January 1, 2002, make it impossible to develop an OSHA recordables metric that accurately compares recent statistics with historical records in any meaningful way. PG&E states it now uses Lost Workdays as the basis for monitoring and evaluating its safety performance as opposed to the OSHA recordables rate, because it believes that lost work time is the most accurate measure of the severity of injuries or illnesses. PG&E argues that the Commission should not adopt CUE's proposed employee safety incentive mechanism because it relies on unreliable data to measure PG&E's safety performance.

CUE admits that PG&E's OSHA recordables rate has continually improved. PG&E's OSHA recordables rate has gone from a high in 1993 of 11.16 to 5.43 incidents in 2002. Given the fact that PG&E's employee safety performance has been consistently improving and we do not adopt a reliability performance incentive mechanism, we find that there is no need to adopt an employee safety incentive mechanism at this time.

c. Call Center Metrics

Under D.95-09-073, PG&E is required to maintain a monthly ASA of 20 seconds, with monthly busy signals a maximum of 1 percent during normal times and 3 percent during outages. PG&E met this standard from January 1998 to December 2002 with only two exceptions that occurred during the energy crisis. After the installation of its new CIS, however, PG&E has been unable to meet the ASA standard. PG&E requests that the Commission adopt a TSL standard instead of the ASA standard. PG&E notes that it is the only utility that is subject to an ASA standard and that its request to switch to a TSL standard is uncontested.

TURN does not oppose PG&E's request, as long as the new standard reflects the same level of service as the existing ASA standard. TURN states that an ASA standard of 20 seconds is equivalent to a TSL standard of 80/20, or 80 percent of the calls answered in 20 seconds. TURN notes that PG&E's current call center situation requires longer wait times for live customer service representatives and a longer time on the phone to handle business in comparison to the previous CIS system. TURN points out that PG&E's 2003 revenue requirement request includes funding to maintain the Commission's 20 second ASA standard. PG&E's call center request incorporates an ongoing increase of $4.63 million (nominal dollars) for additional labor required to compensate for the expected lower efficiency in the new CIS and some increased call volume.

TURN also notes that the ASA standard includes calls answered by PG&E's VRU. During normal conditions, PG&E's customer service representatives answer 60-70% of the calls. Under storm conditions, the VRU handles a larger proportion of calls, such that it is possible that the ASA remains at 20 seconds or less, but the wait time for a representative is much longer. For example, on December 16, 2002, the day of peak call volume of the December storms, the ASA was 12 seconds, with 96% of calls answered in 20 seconds, yet the maximum wait time for a service representative was 76 minutes, and 12% of calls to the customer service representatives were abandoned. Nevertheless, TURN does not recommend that the Commission apply a stringent call center standard on a daily basis for storm conditions at this time, because it would be too expensive.

We agree with TURN that any new standard adopted should reflect the same level of service as the old standard. Since the TSL standard of 80/20 or 80%

of calls answered in 20 second is equivalent to an ASA standard of 20 seconds, we will approve PG&E's request and adopt a TSL standard of 80% in 20 seconds. However, since neither the ASA standard nor the TSL standard currently differentiates between the response time associated with calls answered by a service representative and the response time associated with calls answered by the VRU, we find that the statewide workshops to be instituted under PG&E/ORA Agreement 3, above, should address whether or not call center standards should be revised to better reflect the use of VRU. In particular, the workshop participants should recommend a standard of reasonableness of Average Handle Time in addition to an ASA or TSL standard.

8. Conclusion

With each major storm event and subsequent investigation, it is a challenge to balance the desire to respond immediately and specifically to the unique circumstances that arise against the need to carefully review each event and avoid a crisis management response. We firmly believe that it is of little value to adopt standards that apply to situations of limited duration or that are unlikely to repeat themselves. This proceeding is no exception. Our primary objective in PG&E's TY 2003 GRC is to ensure that PG&E continues to provide utility service at the lowest reasonable rates, maintaining a high level of customer service and satisfaction, and a safe working environmental for its employees. In this phase of the GRC, we are reviewing PG&E's overall reliability performance and storm response to determine whether PG&E has met this level of service and whether additional standards or metrics are necessary to ensure that PG&E continues to provide this level of service. Our detailed review was focused mainly on controversies which arose between PG&E and other parties and a comparison of PG&E's performance to previously-established performing standards.

The December 2002 storms consisted of a series of four severe storms that occurred within a period of nine days. These storms severely tested PG&E's facilities and staff and highlighted many weaknesses in PG&E's organization. While PG&E maintains that its overall reliability performance was reasonable, it admits that its performance during the December 2002 storms requires improvement, especially in the area of outage communications, and has identified several initiatives designed to prevent similar situations from occurring in the future. Other parties also proposed various measures designed to improve PG&E's performance.

While we approve the majority of the PG&E/ORA Agreements, we adopt the PG&E/CUE proposal for a performance incentive mechanism only with main provisions modified. Based on the record in this case, the PG&E/CUE Joint Proposal as presented is not in the ratepayer's interest. We find that the incentive proposal is not likely to result in achieving our basic regulatory objective of maintaining the lowest reasonable rates consistent with safe, reliable, and environmentally sensitive utility service because it would place ratepayers at a significant risk of paying for the same level of reliability two or three times. However, we do find some elements of the mechanism to provide value to encourage improvements in system reliability.

Under cost of service ratemaking, our objective is to adopt a revenue requirement that allows the utility to provide high quality service at just and reasonable rates. Adopting a revenue requirement necessarily includes a presumption of a certain service level. While we support PBR-style incentives in concept, the incentives must be consistent with and not jeopardize our other regulatory goals. We must also avoid using incentives as a substitute for the utilities' statutory obligation to provide high quality service, especially in monopolistic utility markets. In this case, we find that the combination of traditional cost of service regulation and the proposed PG&E/CUE incentive mechanism is likely to result in ratepayers paying twice for the same level of reliability.

As stated above, we direct PG&E to prepare a value of service study prior to its next GRC. The updated value of service information will inform the Commission regarding PG&E's customers' desire for and willingness to pay for increased reliability.

Although we find that PG&E has provided adequate service during normal conditions, based on the record in this proceeding, we also find that PG&E's outage communications during the December 2002 storms do not reflect a reasonable level of service. PG&E has admitted that its storm response needs improvement, but maintains that, on an overall basis, its response to the December 2002 storms was reasonable. We disagree. We believe that while the record demonstrates that the outages and damages caused by the storms were reasonable considering the severity and the back-to-back nature of the storms, given the many outage communication and call center problems that occurred during the storms, we cannot find that PG&E's storm response was reasonable. In particular, PG&E concedes that its method for addressing single customer outages failed, resulting in single customer outages being unrecorded and unresolved. PG&E also admits that calls from emergency personnel were handled in a manner that resulted in police and fire personnel standing by hazardous conditions for excessive periods of time during the storms. Given this evidence, we cannot find that PG&E's overall storm response was reasonable. However, based on the fact that PG&E has admitted its deficiencies and begun implementing remedial measures, we do not find that any sanctions or penalties are necessary. We also note that none of the parties requested sanctions or penalties related to PG&E's storm response.

9. Comments on Alternate Proposed Decision

The alternate proposed decision of the Commissioner Carl Wood in this matter was mailed to the parties on October 14, 2004, in accordance with Section 311(d) of the Public Utilities Code and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____.

10. Assignment of Proceeding

The Assigned Commissioner in this proceeding is Michael R. Peevey and the assigned ALJ is Julie M. Halligan. The February 13, 2003 ACR determined that this was a Ratesetting proceeding and designated the assigned ALJ as the principal hearing officer as defined in Rule 5(l) of the Commission's Rules of Practice and Procedure.

Findings of Fact

1. In December 2002, Northern California experienced a series of severe storms, with high winds and heavy rainfall.
2. These storms caused significant damage to PG&E's electric distribution and transmission facilities, resulting in 1.97 million customer interruptions.
3. PG&E has an obligation under statute to provide highly reliable electric service at minimal cost.
4. The level of service reliability provided by PG&E during normal conditions from 1999 through 2002, as measured by SAIDI and SAIFI, is consistent with the reliability performance standards identified in D.00-02-046.
5. SAIDI, SAIFI, and MAIFI are useful methods of collecting and assessing data on the frequency and duration of system disturbances.

6. It is not particularly useful to compare reliability performance among utilities based on SAIDI, SAIFI, and MAIFI, since different customer counts, system design, geography, weather patterns, and methods of calculating outage duration of the individual utilities will necessarily result in differing performance.

7. PG&E has not prepared a value of service study for at least ten years.

8. The record in this proceeding does not contain value of service information that sufficiently captures the significant changes that have occurred in the electric industry or the California economy in the last decade.

9. The value of service estimates contained in PG&E's Utility Operations Guideline 12003 do not adequately represent PG&E's customers' current value of service and should not be used as the basis for incentive payments or funding.

10. The significant difference in reliability performance between PG&E's divisions favors adoption of division-level performance indicators.

11. PG&E was authorized $34 million in ratepayer funding for a new OIS in its last GRC and seeks approval for $16 million in this GRC for additional OIS improvements over the term of the GRC.

12. Ratepayers have already funded an OIS and a FAS designed to address single customer outages in a coordinated manner.

13. PG&E's request for $3.05 million in expense to upgrade the software for the mobile data terminals is a one-time activity.

14. PG&E's proposal to amortize the cost of enhancing the mapping associations within its OIS over a period of four years will allow the expense to be recovered over a period of time consistent with the expected length of the effort and the amount of projected expenditures per year and should be approved.

15. Adoption of the division-level reliability reporting requirements included in PG&E / ORA Agreement 1 will prevent system-level measures from masking division level performance.

16. Adoption of division level reliability measures as the primary measure of reliability is unnecessary at this time because the Commission may consider either system level measures or division level measures in its determination of reliability performance.

17. There is a need to address definitions of Excludable Major Event, Major Outage, and Measured Event, as well as the restoration performance standard included in Standard 12 of General Order 166.

18. The record in this case supports the fact that PG&E's customers desire improved storm response.

19. The record in this case does not support the fact that PG&E's customers are willing to pay for increased reliability generally.

20. PG&E and CUE have not shown that the proposed incremental annual revenue requirement will increase reliability beyond the levels reasonably expected to result from PG&E's base TY 2003 GRC request.

21. TURN and ORA have demonstrated that PG&E's reliability performance, as measured by the SAIDI and SAIFI performance indicators, is likely to improve without incentive revenues if PG&E pursues the projects proposed in its base TY 2003 request.

22. Given the fact that PG&E's employee safety performance has been consistently improving there is no need to adopt an employee safety incentive mechanism at this time.

23. The statewide workshops to be instituted under PG&E / ORA Agreement 3 should address whether or not call center standards should be revised to better reflect the use of VRU since neither the ASA standard nor the TSL standard

differentiates the response time associated with calls answered by a service representative and calls answered by the VRU.

24. The level of service achieved by an ASA standard is equivalent to the level of service provided by a Telephone Service Level Standard of 80% of the calls answered in 20 seconds.

25. There is value in adopting a set of targeted expectations for SAIDI, SAIFI through a performance incentive mechanism.

Conclusions of Law

1. The Commission is required by Pub. Util. Code § 451 to ensure that PG&E's customers receive reliable electric service at just and reasonable rates.

2. Allowing PG&E to collect and retain more revenue than is reasonably necessary for it to provide safe and reliable utility service would be contrary to the law.

3. PG&E bears the burden of proof to support its application through clear and convincing evidence.

4. PG&E should implement the "improvement initiatives" identified in this decision that would improve PG&E's OIS, thereby improving PG&E's storm response and reliability performance.

5. Agreements 1, 2, 3, 4, 5, 8 and 9 of the PG&E / ORA Joint Testament are in the public interest and should be approved.

6. PG&E and the other proponents of performance incentives have sustained their burden of proving that the incentives are necessary and appropriate and proposals to implement such incentives, including the joint motion of PG&E and CUE, shall be granted with modifications.

7. PG&E's last value of service study was prepared in 1993, with updated estimates prepared for a September 2000 PBR application.

8. PG&E should be directed to conduct a new value of service study prior to its next GRC.

9. In order to allow ORA to review and comment on PG&E's proposed approach and format for the value of service study, PG&E should file an advice letter that sets forth PG&E's proposed approach to conducting the value of service study and a proposed budget for Commission consideration.

10. Ratepayers should not be forced to fund the same OIS functionality twice.

11. PG&E/ORA Agreement 7 should be modified to remove funding for the single customer outage issue and amortize the expense of funding the software upgrades for the mobile data terminals and the mapping association enhancement project over 3 and 5 years, respectively.

12. PG&E's request for $2.45 million in expense and $0.8 million in capital for programming changes to include single customer outages in the OIS should be denied.

13. Approval of a Reliability Memorandum Account to record the costs of approved upgrades to PG&E's OIS would not result in retroactive ratemaking.

14. PG&E should be permitted to establish a memorandum account to track the costs associated with authorized OIS Improvements.

15. The Commission's Energy Division should convene statewide workshops to review the definitions of Excludable Major Event, Major Outage, and Measured Event with the intention of reviewing, clarifying and combining the definitions in D.96-09-045 and GO 166 into a common definition that clearly standardizes the criterion regarding the percentage of customers, or percentage of facilities, that must be affected before an event is considered excludable, including how percentages are to be calculated (i.e. cumulative or simultaneous) and how the start and end times are to be determined.

16. PG&E's request to change from an ASA metric to a telephone service level metric is reasonable, and should be approved.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall implement the following customer service and Outage Information System (OIS) improvements:

    a. Modify restoration prioritization to balance the length of time small numbers of customers are out of power with the need to restore the largest number of customers as quickly as possible;

    b. Simplify the routing of calls from emergency agencies to PG&E to improve the dispatching of PG&E resources to relieve police and fire agency personnel of the need to stand by on site;

    c. Develop additional software to enhance the ability within OIS to increase focus on single customer outages during major events to improve communication with customers and reduce outage duration;

    d. Link its OIS with the mobile data terminals in the field to accelerate the input of outage cause and damage assessment information into the Operations Emergency Centers and estimated time of restoration data into the OIS to improve the speed of assessing damage and sharing outage information with customers;

    e. Integrate the three existing outage databases (the Supervisory Control and Data Acquisitions, OIS and Distribution Operators Logging Information Program) to reduce the number of manual entries an operator must make to improve efficiency and reduce outage duration;

    f. Enhance mapping associations within the OIS so that smaller portions of PG&E's circuitry can be pinpointed for purposes of determining on a real-time basis a more accurate number of customers affected by outages and more accurate outage information;

g. Add new toll-free numbers for customers who are without power for more than 48 hours; and

h. Implement a campaign to urge customers to verify the accuracy of the phone number on their PG&E bill.

2. PG&E shall implement Agreements 1, 2, 3, 4, 5, 8 and 9 of the PG&E / Office of Ratepayer Advocates (ORA) joint testimony, as described in Appendix A.

3. PG&E shall submit division-level reliability data annually, concurrent with the system-level reliability report required by D.96-09-045. The reliability measures will include division level average interruption duration, average interruption frequency, customer average interruption duration and momentary average interruption frequency.

4. PG&E shall investigate and report to the Commission when the division level Average Interruption Frequency Index, Customer Average Interruption Duration Index (CAIDI) and Momentary Average Interruption Frequency Index (MAIFI) vary by 10 percent or more in any division from the five-year rolling average of reliability performance.

5. The Commission's Energy Division shall schedule workshops consistent with ORA / PG&E Agreement 3 within 90 days of this decision.

6. PG&E shall perform, or cause to be performed, a customer value of service study prior to its next General Rate Case (GRC). PG&E shall file an Advice Letter with the Commission within 90 days of this decision detailing its proposed value of service study approach and cost estimate for Commission review and approval.

7. PG&E is authorized to establish a memorandum account (consistent with the Reliability Improvement Memorandum Account proposed in PG&E / ORA

Agreement 7) to track the following costs associated with funding the following OIS upgrades:

a. $3.050 million in expense, amortized over three years, to link the OIS to the mobile data terminals;

b. $3.250 million in expense to integrate the three existing outage databases (Supervisory Control and Data Acquisitions, OIS and Distribution Operators Logging Information Program; and

c. $7.360 million in expense ($460,000 in 2003 and $2.3 million in each of the years 2004, 2005 and 2006) to enhance the mapping associations within the OIS so that smaller portions of PG&E's circuitry can be pinpointed.

   The amount incurred in 2003 is recoverable to the extent that PG&E's actual expenses in Federal Energy Regulatory Commission (FERC) Account 588 exceed 2003 GRC adopted FERC Account 588 expenses by the amount that actual expenses exceed adopted expenses up to the amounts in the Memorandum Account. For the expenses incurred in 2004, 2005 and 2006, the amounts are recoverable up to the above incremental amounts to the extent that PG&E's total electric O&M expenses exceed GRC adopted O&M expenses.

8. PG&E shall be subject to the targeted reliability metrics as outlined in section 7.4 above.

9. Within 10 days of the effective date of a final decision on Phase 1 of PG&E's Test Year 2003 GRC, PG&E shall file revised tariff sheets to implement the revenue requirements and accounting procedures set forth in this decision.

This order is effective today.

Dated ____________________________, at San Francisco, California.

Appendix A - PG&E/ORA Joint Testimony

Agreement 1: PG&E will supplement its annual reliability report[38] system data with reliability measurements by division, but not by area. The reliability measurements will include SAIDI, SAIFI, CAIDI and MAIFI. The format for reporting these division data would be developed in consultation with ORA. PG&E will provide ORA with all filings/submissions related to reliability currently provided to other divisions within the Commission.

Agreement 2: PG&E will investigate and report to the Commission when the previously described reliability performance measures vary by 10 percent or more in any division and/or 5 percent or more at the system level from the five-year rolling average of reliability performance. PG&E will calculate performance variations using values that exclude major events as defined by the prevailing regulation (currently D.96-09-045) and as implemented by PG&E in compliance with this regulation. PG&E will submit investigative reports by May 1 each year. The report will be filed with the Commission's Executive Director, and copies will be made available to interested persons upon request.

In addition, PG&E will investigate and report on all weather-related excludable major events for each division in which reliability performance, as measured by CAIDI, varies by 25 percent or more from the division benchmark. The division benchmark will be calculated from the rolling average of the prior 10 weather-related excludable events, whether the event is excludable at a system-wide level or is division-specific due to a declared state of emergency; or a rolling five-year average, whichever yields more event days. PG&E also agrees to provide such reports for the system when the system performance varies by 10 percent or more from the system benchmark. The system benchmark will be calculated from the rolling average of the prior 10 weather-related systemwide excludable major event dates, or a rolling five-year average, whichever yields more event days.

Agreement 3: PG&E and ORA recommend that the Commission initiate statewide workshops to address definitions of Excludable Major Event, Major

[38] The report required by Decision 96-09-045 which is filed annually on March 1.

Outage, and Measured Event, as well as the restoration performance standard included in Standard 12 of G.O. 166. The list of topics to be considered in the workshops includes:

- Examine if the level of the CAIDI benchmark in G.O. 166 is realistic and, if not realistic, establish realistic, but not necessarily uniform, benchmarks that could actually aid in measuring a given utility's restoration efforts;

- Review, clarify, and / or combine applicable definitions currently in D.96-09-045 and G.O. 166 into a common regulation that clearly standardizes the criterion regarding the percentage of customers, or the percentage of facilities, that must be affected before an event is considered excludable (i.e., how percentages are to be considered, (cumulative or simultaneous), an objective basis for determining the start and end times for an excludable event. etc.);

- Determine how outages incurred through restoration activities during excluding events are to be treated and determine how these additional outages should influence the counts for additional customer interruptions;

- Determine how the organization of the various utilities (i.e., districts, divisions, areas, etc.) affects how reliability is monitored during normal operations and those events that take place during abnormal events and create standards for allowing utilities to exclude outage data, during excludable events, only for those operating areas where the customers themselves actually experienced the event or where field staff from an area are utilized to aid an area where the customers experienced the event;

- Confirm that all utilities consistently interpret and apply the requirements and definitions within D.96-09-045 and G.O. 166 (e.g., in the definition of a G.O. 166 Measured Event, what is exactly incorporated by the range "10 percent simultaneous" and "40 percent cumulative" of customers affected?); and,

- Ensure that the Commission is being provided with complete details from all utilities regarding how each interprets the requirements in Appendix A of D.96-09-045.

PG&E and ORA agree that no further reporting regarding major outages or excludable major events is required beyond the Commission's current requirements. In addition, PG&E agrees that modifications to its Utility Operations Electric Emergency Operations Plans will be made in consultation with ORA and Energy Division.

Agreement 4: PG&E will install as many additional sets of overhead fuses in 2003 to fully utilize the GRC requested amount of $5.4 million in MWC 49. This is expected to result in the installation of no fewer than 2,000 overhead fuses in 2003 associated with this MWC. PG&E will report to the Commission, including ORA, on the number of overhead fuses installed and unit costs associated with MWC 49 in 2003 through 2006.

In addition, beginning in 2004, PG&E agrees to continuously maintain three years of annual budget cycle submittals, final budget authorization, actual expenditures, and the number of installations for all work performed in MWC 08,09, and 49. PG&E will provide these documents upon request of the Commission, including ORA.

Agreement 5: PG&E will modify current restoration practices to balance length of outages with number of customers affected and will keep ORA actively involved and informed in the process of developing this policy.

Agreement 6: PG&E will perform an assessment of value of service values (a "VOS assessment") by December 31, 2004 that will address the following issues:

- Based on a survey of prior VOS studies, the parties have noted significant differences within and among those studies. The significant differences include value of service between customer classes and between different approaches within the same customer class. The magnitude of these differences is likely to overshadow the differences attributable to changes over time (e.g., those that would be captured by a new VOS survey). The VOS assessment shall analyze and critically appraise these differences, and shall appraise the relative merit of the willingness to pay versus willingness to accept results.

- With respect to storm response management, PG&E will make its best efforts to quantify the effect of critical additional resources on restoration time.

- PG&E agrees that the VOS assessment will set forth balanced and complete reasoning in the derivation of proposed VOS values and the VOS assessment shall be conducted in such a way that it does not simply attempt to justify the values currently contained in UO Guideline G12003.

- PG&E shall attempt to have the VOS assessment peer-reviewed, but is not required to do so. If the VOS assessment is peer-reviewed, PG&E shall append peer comments to the VOS assessment.

The VOS assessment shall include the following:

- PG&E will recommend as many different VOS values as the Company believes is necessary;

- Documentation showing how each VOS measure has been translated into PG&E's recommended VOS measures;

- For purposes of investment planning, PG&E will set forth its findings and recommendations for the weighting of differences between customers classes;

- PG&E may additionally recommend as many different ways to use VOS as best reflect its operations; and

- PG&E will make its best efforts to investigate a VOS approach that is workable and useful for application to storm response management and for service guarantees.

PG&E and ORA agree that conducting a VOS survey is not warranted at this time. ORA and PG&E anticipate that the VOS assessment envisioned by the parties can be performed within PG&E's existing resources. If PG&E recommends a survey, PG&E will file an advice letter that: 1) Sets forth a proposed budget; and, 2) states that PG&E shall enter the costs of said survey into a memorandum account for future potential rate recovery. PG&E would consult with ORA and obtain agreement prior to filing the advice letter.

Agreement 7: PG&E will establish a Memorandum Account to record the costs associated with specific upgrades to PG&E's OIS and associated emergency response systems for an amount up to $9.0 million in 2003, and $2.3 million for each of the years 2004, 2005 and 2006 (2003 nominal SAP dollars). The amount incurred in 2003 is recoverable to the extent that PG&E's actual expenses in Federal Energy Regulatory Commission (FERC) Account 588 exceed 2003 GRC adopted FERC Account 588 expenses by the amount that actual expenses exceed adopted expenses up to the amounts in the Memorandum Account. For the expenses incurred in 2004, 2005, and 2006, the amounts are recoverable up to the above incremental amounts to the extent that PG&E's total electric O&M expenses exceed GRC adopted electric O&M expenses.

Agreement 8: PG&E will monitor and report to ORA on its implementation of the existing measures in its action plans as well as its investigations into additional technical measures to improve the accuracy of its Voice Response Unit (VRU) systems and potential methods to prevent its Safety Net line from being overburdened during high-call-volume emergencies.

Agreement 9: PG&E and ORA agree on a mutual approach to monitoring and reporting to ORA on any needed adjustments to its Outage Information System (OIS), Customer Information System (CIS), Field Automation System (FAS), VRU and all customer interface and response systems that would aid PG&E in making resource deployments to address outages.

(End of Appendix A)