AN INDEPENDENT, FULL SCOPE ROOT CAUSE INVESTIGATION OF SAN FRANCISCO DECEMBER 8, 1998 OUTAGE

(Interim Report)

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PURPOSE OF INVESTIGATION

The purpose of this full scope root-cause investigation is to prevent the recurrence of a San Francisco outage similar to the one that occurred on December 8, 1998. The investigation is intended to review and, if necessary, improve work practices, processes, and management systems in order to reduce the probability and consequences of a recurrence, including the use of hindsight to identify all errors and sources of these errors. Without addressing all three areas (work practices, processes, and management), the true causes of an event are often missed. The causes identified in this report were discovered and analyzed using all information and results available to the California Public Utilities Commission (CPUC) at the time this report was written. At the time of the San Francisco outage, not all pertinent information was available to the involved personnel during the time frame in which relevant actions were taken and decisions were made. Therefore, conclusions reached in this investigation cannot be used as evidence of imprudence.

The purpose of using such a comprehensive approach is to avoid sub-optimization of the improvements that may transcend electrical generation, distribution, and transmission systems.

AN INDEPENDENT, FULL SCOPE ROOT CAUSE INVESTIGATION OF THE SAN FRANCISCO DECEMBER 8, 1998 ELECTRICAL POWER OUTAGE

EXECUTIVE SUMMARY

- Local Protection
- Distant Clearing
- Vulnerability of San Francisco Operating Criteria

OPPORTUNITIES FOR IMPROVEMENT (OFI) DURING RECOVERY STAGE

- Command and Control
- Communication Errors
- Problem Identification
- Restoration of Unaffected Areas
- Maintenance of Breakers

OPPORTUNITIES FOR IMPROVEMENT (OFI) FOR MANAGEMENT

- Performance Monitoring and Trending
- Expectation Propagation
- Analysis of Underlying Human Performance Problems
- Lessons Learned Process

OPPORTUNITIES FOR IMPROVEMENT (OFI) FOR FUTURE PREVENTION AND INVESTIGATION

- Integration to avoid sub-optimization
- Independence
- Prevention
- Recommendation – An Independent Outage Prevention and Investigation Council

RECOMMENDATION

- Recommendation Matrix

LIST OF FIGURES

EXECUTIVE SUMMARY

This investigation was initiated by the California Public Utilities Commission's (CPUC's) Order Instituting Investigation (OII), No. 98-12-013, issued on December 17, 1998. The purpose of the investigation was to understand the underlying causes of the December 8, 1998 San Francisco outage and to recommend cost-effective actions to prevent future recurrences i.e., prolonged San Francisco outages. To avoid sub-optimization of future improvements, the team was asked by the Consumer Services Division (CSD) of the CPUC to examine all potential underlying causes involved in the outage, including human errors, equipment failures, process failures, and management system deficiencies. To understand the underlying causes, the areas investigated cover various organizations directly or indirectly involved in the outage and cover transmission, distribution, and generation of electricity. The investigation has been supported by personnel from the CPUC, California Independent System Operator (CAISO), and Pacific Gas & Electric (PG&E) to help collect relevant data related to the December 8, 1998 outage and Pacific Gas and Electric's (PG&E's) transmission and generation management systems. The investigation team appreciates the support of these organizations.

GENERAL OBSERVATIONS

The investigation team, on behalf of the CPUC, worked closely with CAISO and PG&E managers to gather data. Although the investigation team's main purpose was the identification of errors that resulted in the prolonged outage and actions necessary to ensure system wide improvement, the team noticed that PG&E has some major strengths that can lead to more reliable service. These include an excellent technical capability that provides accurate predictions of electrical system transients and high senior management expectations for the performance of PG&E's work force. After the December 8 outage, the team noticed that PG&E's management had already taken many positive steps to improve the deficiencies identified in PG&E's root cause investigation report, issued on January 25, 1998. On balance, the investigation team believes that PG&E's work force is generally competent and motivated, and PG&E's senior management is open, involved, and receptive to continuous improvement.

THE INVESTIGATION OF THE SAN FRANCISCO OUTAGE

The San Francisco outage occurred on December 8, 1998. It is estimated that more than one million people (or 456,000 customer accounts) were affected by the outage. The outage started at 8:15 a.m. and ended at 3:54 p.m. with a total duration of seven hours and thirty-nine minutes. About 85% of the customers had their power restored by 2:05 p.m.

The financial, health, and safety impact of the San Francisco outage was very significant, estimated to be between $200 million and $400 million. From initiation through full recovery from the outage, more than 140 human errors occurred. These human errors were manifested as construction crew errors, operation errors, equipment testing errors, and maintenance errors.

PG&E's System Average Interruption Duration Index (with major disasters such as major storms and earthquakes excluded) in terms of minutes of power interruption per customer per year has seen an upward trend since 1990. This index is an objective measure of the average overall reliability of the transmission and distribution system. The index has been in place since 1988 and reached an all time high for PG&E in 1998.

Because of the high financial, health, and safety impact of the outage, prevalent human errors throughout the event, and an alarming upward trend of interruption duration since 1990, the investigation team believes that there is room to improve. Improvement will reduce future risk of outages for San Francisco electricity consumers.

The investigation team believes that to achieve improvement in a step-change fashion, a full scope examination of PG&E's work practices, processes, and management systems should be performed to identify and improve the existing weakest areas. Also, to avoid sub-optimization of improvements, the three aspects of electricity supply, i.e., generation, transmission, and distribution, should be examined in an integrated fashion. This belief is shared and supported by the CSD.

INVESTIGATION RESULTS

The investigation team has examined relevant areas in the three phases of the outage – event initiation, consequence containment, and outage recovery – as well as PG&E's existing management system. The factors that are needed to improve future PG&E performance in preventing and responding to major outages are called Opportunities for Improvement (OFIs). OFIs correct or eliminate human error inducers and broken barriers that are designed to prevent expansion of failures of small magnitude to failures of large magnitude. The investigation team believes that the OFIs identified by the team, if adopted and correctly instituted by PG&E in a timely manner, will significantly reduce the probability of future San Francisco prolonged outages and will, even if an outage occurs, significantly reduce the recovery time from the outage.

Based on its investigation into PG&E's processes and management system, the investigation team found that the human errors resulting in the failure to remove grounds that initiated the December 8, 1998 outage are symptoms of several underlying causes (or OFIs). *These underlying causes are:*

(1) *inadequate management control of human performance in the field;*
(2) *error-prone procedure (and switching log) preparation and development process; and,*
(3) *vulnerability in the existing electrical protection systems, which make them less capable of preserving San Francisco's critical load in the event of faults with large voltage fluctuations.*

The underlying causes (also called common causes) are the drivers embedded in the organization that ultimately induce many human errors and allow events of small magnitude to become disasters. Without correcting these underlying causes, i.e., just focusing on correcting one or two types of human errors, it will not be possible to effectively prevent recurrence of a San Francisco outage. **Figure 1** illustrates the relationship between the three underlying causes and various types human errors committed throughout the outage. Human errors are symptoms of the underlying causes.

The identified OFIs are briefly described in the following four sections, under the titles of event initiation phase, consequence containment phase, outage recovery phase, and management system improvement. Because San Francisco's electrical system is very unique and the processes and management systems examined in this investigation are unique to PG&E, the identified OFIs and recommendations in this report may not be applicable to other electrical utilities companies without detailed analysis. However, the general concepts and analysis techniques presented in this report are not unique to PG&E and San Francisco.

Note that existence of OFIs does not indicate substandard performance relative to other utility companies or established industry standards. Rather, it means that these areas are currently inadequate to prevent the recurrence of a prolonged San Francisco outage, but that they can be improved with cost effective measures.

EVENT INITIATION PHASE

This phase covers the human errors involving ground removal that contributed to the initiation of the electrical fault at the San Mateo substation. Based on the data examined by the investigation team, the two underlying causes that contributed to the initiation of the event were error prone procedures and human error prone work practices. Based on the fact that there are many human error traps, such as vague instructions, in the procedures (e.g., Grounding Manual), some human errors are inevitable in the execution of the procedure. Therefore, the error proneness of both the procedure and work practices contributed to the ground removal problem. The OFIs that can be corrected to reduce the probability of initiating electrical faults due to inadequate ground removal are:

- Inadequate supervisory skills to command and control field work (OFI-1)
- Error prone work culture for the involved personnel that tends to bypass procedures and work practice requirements (OFI-2)
- Lack of a positive means to track and count grounds installed and removed (OFI-3)
- Inadequate post-work testing procedure that allowed the electrical bus to return to service before finding unremoved grounds (OFI-4).
- Inadequate attention to critical operation and critical equipment (OFI-5)

UNLESS UNDERLYING CAUSES ARE ADDRESSED, THE RECURRENCE IS DIFFICULT TO PREVENT. THE NEXT OUTAGE MAY BE INITIATED FROM ERRORS UNRELATED TO GROUNDING REMOVAL…

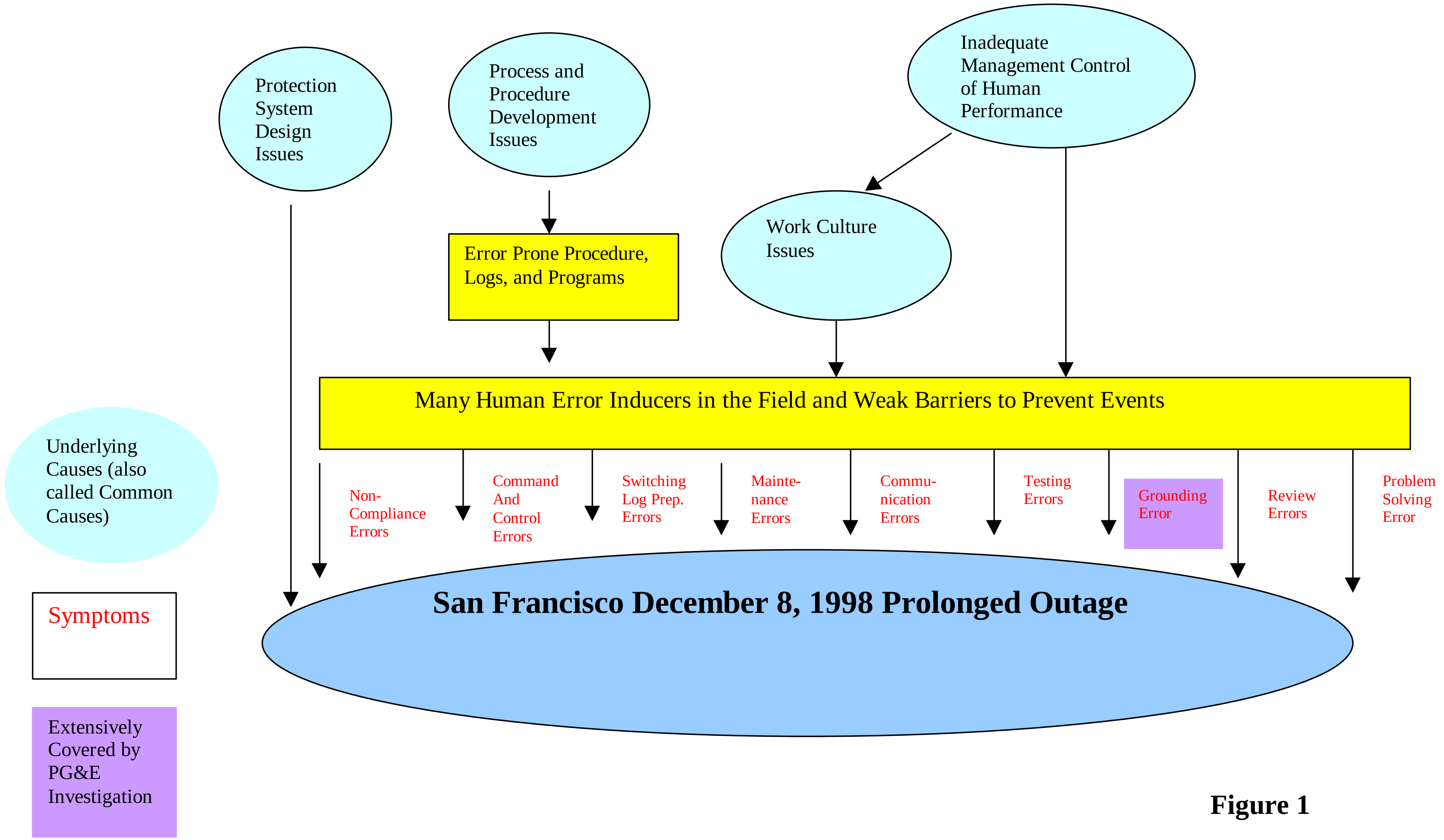


Figure 1

CONSEQUENCE CONTAINMENT PHASE

This phase covers the period between the fault initiation at the San Mateo substation to the time when the San Francisco electrical load was tripped off. After the initiation of a fault, there are local and distant protection systems designed to contain the consequences of the electrical fault. If these local and distant protection systems fail, the San Francisco Operating Criteria (SFOC) is designed, as a last defense, to isolate the San Francisco electrical system and preserve its critical load. The isolation ensures that the critical load be served by Potrero and Hunters Point power plants, located within the San Francisco area, and that restoration can proceed expeditiously.

S all of the investigations have demonstrated, the fault could have been confined and localized at SMS if the differential relay for Bus 2 Section D was cut in.

PG&E reported that the main reason related to the failure to cut in the differential relay was that the operator at the San Mateo switching center missed the cut-in instructions in the switching log. Contrary to PG&E's report, the investigation team believes that the underlying cause of the failure to cut in the differential current relay was error proneness of the switching log preparation process, rather than operator errors in failing to follow the switching log that returned the Bus 2 Section D to service. The investigation team believes that the cut-in step noted in the switching log was not there during the switching operation and was falsified into the switching log after the switching error was made and after the initiation of the electrical faults. Therefore, the underlying cause for the failure to cut in the differential relay was related to inadequate switching log preparation, not an operator error.

The OFIs that can be corrected to contain consequences of a fault are:

- Error prone switching log preparation process (OFI-6)
- Error prone work culture that is not self critical or forthcoming with problems for the involved personnel (OFI-7)
- Inadequate protection system for local clearing (OFI-8)
- The protection system for distant clearing is not designed for fast clearing of bus faults (OFI-9)
- Current San Francisco Operating Criteria (SFOC) not designed to preserve critical load against disturbance of large voltage fluctuations or loss of generation after islanding (OFI-10)

OUTAGE RECOVERY PHASE

This phase covers the time period from the point at which San Francisco dropped its electrical load to when that load was totally recovered. The total outage time on December 8, 1998 was seven hours and thirty-nine minutes. Based on the data examined by the team, the recovery time could have been reduced to about three hours from initial fault to restoration of the last section of customers in the distribution system had the following OFIs been avoided or corrected:

- Inadequate command and control during recovery (OFI-11)
- Inadequate human performance in communication (OFI-12)
- Not identifying and confirming the grounding problem in a timely manner (OFI-13)
- Not restoring the affected, but undamaged, lines in a timely manner (OFI-14)
- Not recovering the distribution load using a staggered recovery strategy upon recovering the transmission load (OFI-15)
- Inadequate Maintenance of Breakers (OFI-16)

In order to institute the staggered recovery strategy, it is necessary for PG&E to integrate its Distribution Switching Center and its Transmission Operation Center. This integration requires both hardware and software investments. At the present time, PG&E's load recovery strategy and operator training emphasis is to recover the majority of its transmission lines (i.e., energizing the lines with voltage) after a system blackout before picking up the distribution load. To speed up the load recovery for metropolitan consumers, it is a common practice to restore transmission lines and distribution loads in a staggered fashion. That is, part of the distribution load is picked up right after a portion of the transmission system is energized. Then, more of the distribution load is picked up after another portion of the transmission system is energized. The staggered recovery load recovery strategy usually provides a much faster recovery time during a major outage.

MANAGEMENT SYSTEM IMPROVEMENT TO CONTROL HUMAN PERFORMANCE

More than 140 human errors were revealed throughout the December 8, 1998 outage. Because the human errors were very prevalent throughout the San Francisco outage, the investigation team examined several critical factors that are needed to control and improve field human performance. These factors are illustrated in **Figure 2**. **Figure 2** is called the human performance control loop. It begins with setting up expectations of workers' human performance by the senior management. The senior management's expectations are translated into various requirements in the operating procedures (such as the Grounding Manual or switching logs) and passed down through middle managers to supervisors (in supervisory expectations). Supervisory expectations and operating procedures set up the behavior standards in the field.

As can be seen in **Figure 2**, to control human performance in the field, human performance has to be constantly monitored and deviations from the senior management's expectations must be noted. The root causes of the deviations are analyzed and cost effective corrective actions are implemented in a timely manner to change human performance of the organization. If all of the elements (such as performance monitoring, root cause analysis, accountability, etc.) depicted in the human performance control loop are in existence, the organization's human performance will always remain at the same level as that expected from the senior management. If some

MANAGEMENT CONTROL OF HUMAN PERFORMANCE CAN BE IMPROVED…

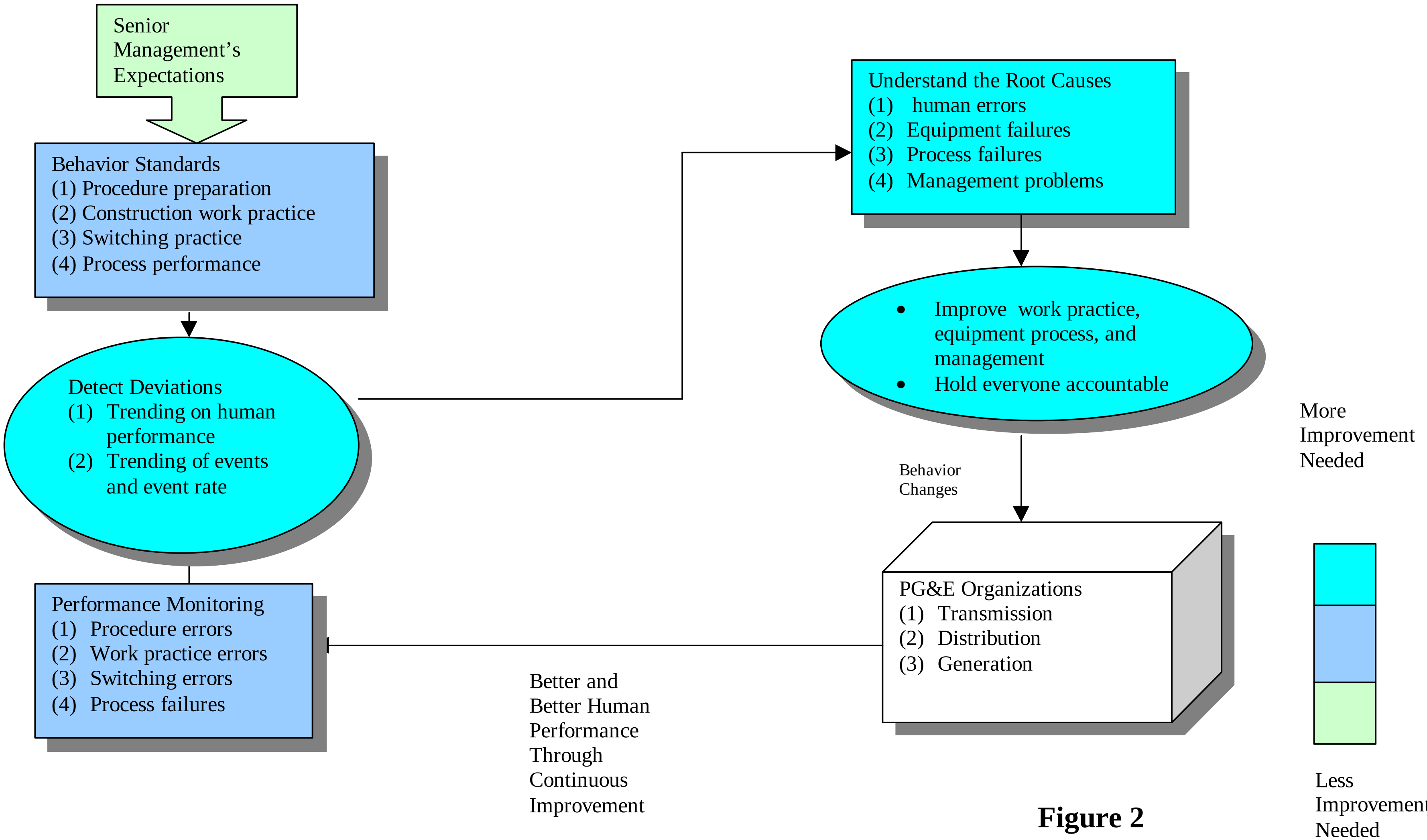


Figure 2

of the elements are missing, the human performance will fluctuate or be substandard when there are resource challenges (such as high turn-over rates, inadequate training, etc.) to the organization.

Figure 3 shows the benefits of a strong human performance control loop. As can be seen in this figure, organizational disturbances (such as staff reduction, budget cuts, etc.) may or may not cause human performance problems. However, if the disturbances do cause human performance problems, a strong human performance control loop is able to detect the degradation in a timely manner, identify the most cost-effective methods to fix the problems, and to maintain a high human performance over time. If the human performance loop is weak, organization disturbances may cause continuous human performance degradation without being intervened by the senior management. In general, it is very difficult to determine the exact impact from each organizational disturbance before its negative impact is manifested as degradation in human performance. With a strong human performance control loop, the negative impact of the disturbance is rapidly mitigated through a good root cause and underlying (common) cause analysis.

Based on the data examined by the investigation team, the senior management's expectations of the workers' human performance are relatively high. Nevertheless, the high management expectations did not propagate to the performance standards in the field. The following OFIs exist to improve the human performance control loop:

- Lack of human performance monitoring and trending (OFI-19)
- Inadequate translation of senior management's expectations into operating procedures and supervisor's expectations (OFI-20)
- Inadequate analysis capability to identify underlying human performance problems (OFI-21)
- Inadequate lessons-learned process to learn lessons from previous events (OFI-22)

PG&E has started a root cause program for its construction, distribution, and transmission personnel since 1998. This root cause program helps correct problems specific to a switching center. However, the program is incapable of detecting and correcting underlying human performance issues (such as procedure development process problems). This root cause program helps correct problems specific to a switching center.

The investigation team believes that the main reasons for prevalent human errors at PG&E are related to the problems in the human performance control loop. Unless the human performance control loop is set up and functioning, human performance improvement will be minimal.

Moreover, without a strong control loop, work culture in the field tends to be error prone and degrade over time. Once an error prone work culture is established, the human error rate will continue to increase unless there are quick and to-the-point interventions.

FUTURE OUTAGE PREVENTION AND INVESTIGATION

During the two month investigation, the investigation team observed the following:

- Many state and federal agencies are involved in regulation or oversight of different parts of the generation, distribution, and transmission system.
- Without an integrated, independent investigation, root causes of outages are hard to find and improvement may be sub-optimized. Under the present regulated system, the incentive for a utility to perform such a full scope, in-depth investigation is not high.
- Within a utility, the transmission, distribution, and generation departments do not learn lessons from each other.
- Among utility distribution companies, which control transmission and distribution systems, lessons learned or good practices from one utility are usually not shared with other utilities.
- Very few "preventive" measures, such as analyzing and improving error prone processes and work practices to reduce outage probabilities, are in place to prevent outages.

To ensure long term reliability of the electricity supply to the consumers, it seems reasonable that future outage events in which the consequence exceed a certain threshold (such as exceeding 100,000 consumer-hour outage) be investigated by an independent board, which would be capable of performing full scope investigations. The board would ensure that lessons learned and good practices are shared among utilities. The board could also be chartered to coordinate with various state and federal agencies to ensure that measures to prevent outages are in place in generation, distribution, and transmission, and are not sub-optimized.

RECOMMENDED ACTIONS

The recommended actions to improve or correct OFIs identified by the investigation team are summarized in **Figure 4**. In this figure, the recommended actions are grouped into twenty-six items. The items presented in **Figure 4** are categorized by a four by three matrix based on areas of impact. The investigation team believes that they are cost-effective to help prevent recurrences and may help to recover rapidly from future outages similar to the December 8, 1998 San Francisco outage. If adopted by PG&E, the implementation effectiveness of the recommendations stated in this investigation report should be assessed and tracked on a yearly basis until PG&E's human error rate in the field has dropped significantly and its protection system has been improved. The recommended actions should be implemented immediately to provide an instant improvement in PG&E's human performance. These recommendations, if adopted, are designed to achieve a sustained improvement in the future.

BENEFITS OF A STRONG HUMAN PERFORMANCE CONTROL LOOP

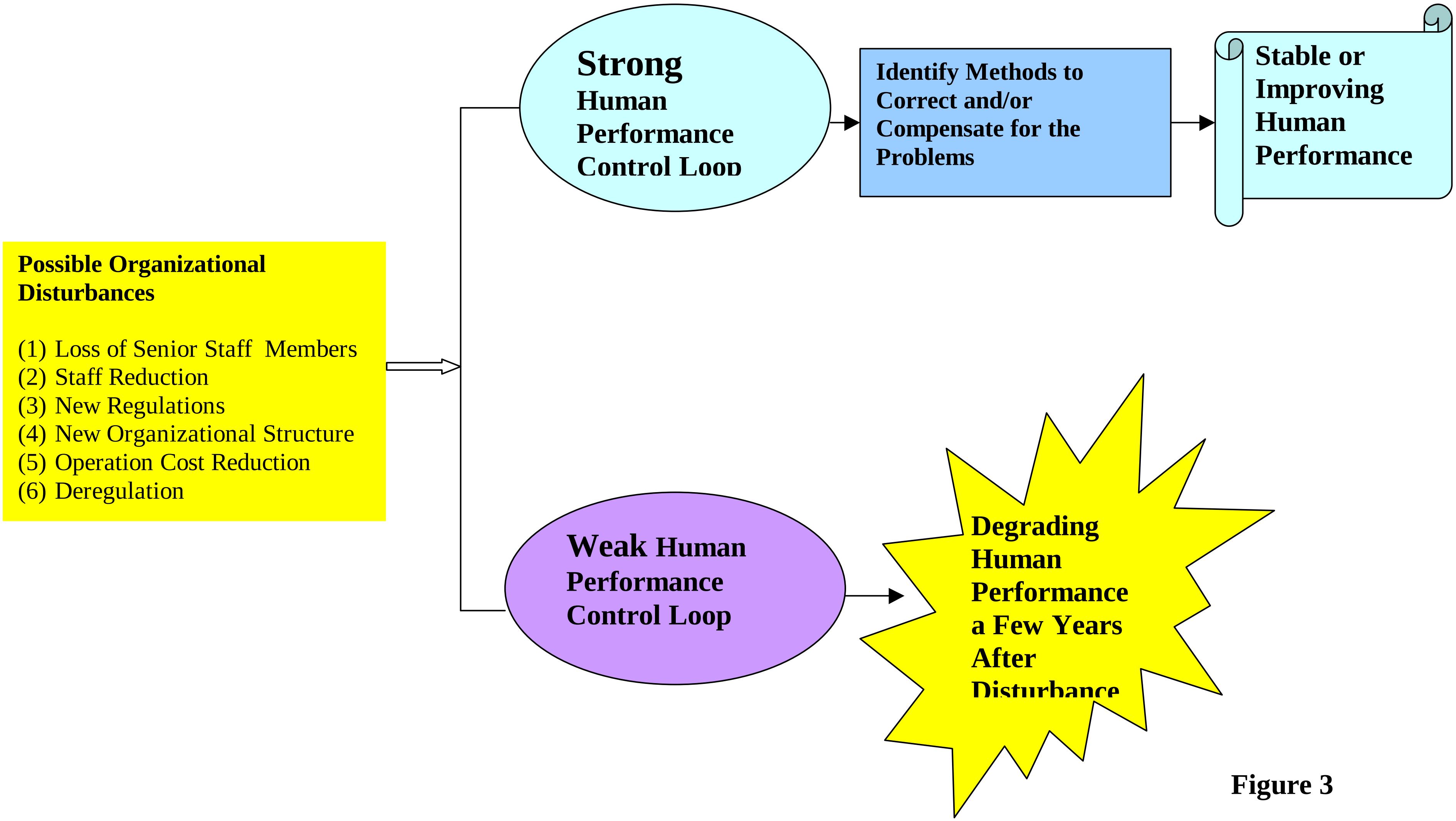


Figure 3

RECOMMENDATION MATRIX TO IMPROVE OFIs

	Event Initiation Phase	**Consequence Containment Phase**	**Recovery Phase**
Work Practice Improvement	• Work Culture Assessment and Improvement • Human Error Reduction Skill Improvement • Supervisory Command and Control • Critical Equipment and Operation Concept	• Work Culture Assessment and Improvement	• Repeat Back Communication • Transmission Operation Center (TOC) Command and Control
Equipment or Design Improvement	• Interlock between Differential Relay and Breakers • Ground Cable Visibility	• Digital Distant Relays • Relay Setpoint Alignment (Zone 2 Protection for 3-Phase Faults) • Under Voltage Load Shedding • Load Shedding for Generation-Load Balance	• Integration of Distribution Switching Center (DSC) and TOC
Work Process Improvement	• Tagging and Pinning of Grounds • Bus Post-Maintenance Tests	• Tracking Abnormal Operation Status	• Equipment Installation Testing • Breaker Post Maintenance Testing • Maintenance Backlog Reduction
Management System Improvement	• Management Expectation Alignment For Human Performance Control • Human Performance Monitoring and Trending • Root Cause and Common Cause Analysis • Corrective Action Program • Integrated Vulnerability Assessment	• Integrated Protection System Assessment	• Staggered Load Recovery Strategy • Enhanced Training on Problem Identification and Recovery of Affected Areas

Figure 4

INTRODUCTION

BACKGROUND

This investigation was initiated by the California Public Utilities Commission's (CPUC's) Order Instituting Investigation (OII), No. 98-12-013 issued on December 17, 1998. The purpose of the investigation is to understand the underlying causes of the December 8, 1998 San Francisco outage and to recommend cost-effective actions to prevent the recurrence of a prolonged San Francisco outage. To avoid sub-optimization of future improvements, the team was asked by the CPUC to examine all potential underlying causes involved in the outage, including human errors, equipment failures, process failures, and management system deficiencies. To determine the underlying causes, the areas investigated covered the various organizations directly or indirectly involved in the outage and covered the transmission, distribution, and generation of electricity. The California Independent System Operator (CAISO) supported the investigation by helping to collect relevant data related to Pacific Gas and Electric's (PG&E's) transmission and generation systems.

The purpose of the investigation was to understand the underlying root causes of the December 8, 1998 San Francisco Outage and to prevent recurrence of a prolonged electricity outage in San Francisco. To carry out the investigation, the CPUC employed Performance Improvement International (Orange County, California, USA), which assembled a team of investigation professionals and consultants. This team is independent of Pacific Gas and Electric Company (PG&E) and other state and federal agencies that are directly or indirectly involved in the December 8, 1998 event. The team was chartered to perform a full-scope and in-depth analysis on the reasons for the outage and ways to improve performance in order to prevent a recurrence with a high degree of assurance. The investigation team was commissioned on February 1, 1999 and it concluded its investigation on March 26, 1999. Its major findings are summarized in this report.

The report is divided into three major parts. The first part describes the investigation purpose, process, scope, and interactions with PG&E and the ISO. The second part describes the Opportunities for Improvements (OFI) based on the facts that surfaced during the outage and the data collected during the investigation. The OFIs are viewed by the investigation team as the areas that can be improved cost-effectively to prevent a recurrence. OFIs, if not corrected in a timely manner, may induce future events similar to the December 8 outage. **Figure 5** illustrates the definition of an OFI. The third part of the report contains the recommendations to correct OFIs.

WHAT IS AN OPPORTUNITY FOR IMPROVEMENT (OFI)?

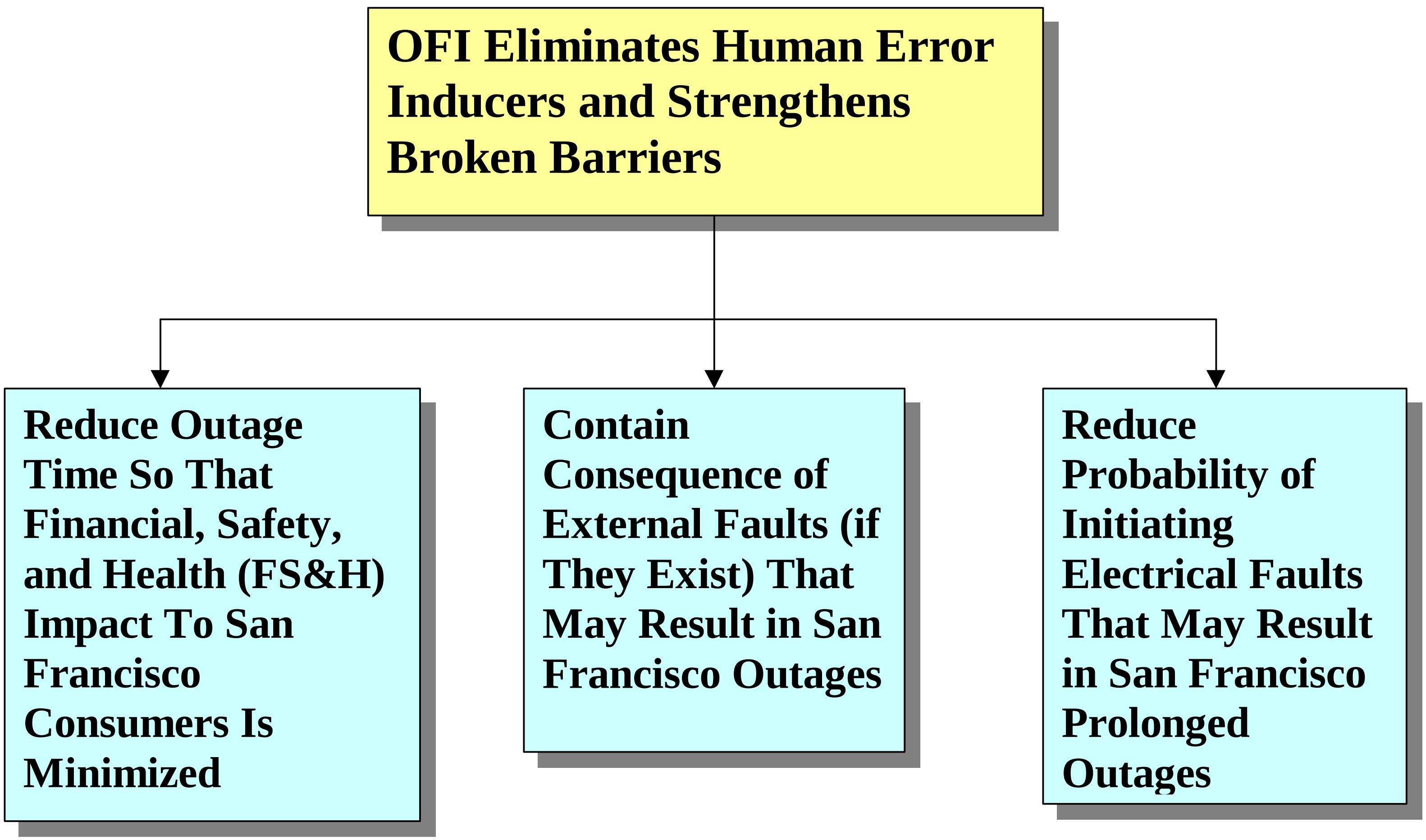


Figure 5

LIMITATION OF THE INVESTIGATION

Limitations on the team's ability to collect relevant data provided hurdles to understanding some of the underlying root causes of the December 8 outage. For example, the investigation team was unable to interview PG&E workers involved in the event. Interviews of other field workers performing similar work were not adequate to identify the actual work practices at the facilities involved in this incident. Moreover, the investigation team was unable to perform a wide ranging safety culture survey necessary to understand the extent and severity of the procedural non-compliance culture.

To work around the limitations imposed on data collection, the investigation team used indirect data to reach preliminary conclusions about the workers' non-compliance culture and its potential underlying causes. The team recommends that the CPUC and the ISO perform a follow-up culture survey and analysis to truly understand the underlying causes and develop positive means to eliminate these causes.

An investigation is only as valid as its input data. The investigation team relied on PG&E's notes of interviews with the involved workers, data contained in PG&E's original root cause analysis report, and PG&E's responses to data requests submitted by the investigation team and CAISO to reach its conclusions. The validity of its conclusions depends on the validity of the information provided by PG&E. Without being able to interview the workers involved in the December 8 outage, the investigation team can only validate the data provided to the team with a consistency check. None of the data used in the investigation could be independently verified.

Also, because the investigation team focused on the December 8 outage in an attempt to prevent a recurrence, it did not assess the overall adequacy of PG&E's work practices, processes, and management compared to industry standards. Therefore, OFI's identified in this report should not be treated as deficiencies or below-standard practices. Rather, they should be viewed as factors that can be improved to prevent a recurrence.

GOOD PRACTICES NOTED

The investigation team noted several good practices that have helped PG&E maintain the reliability of its electricity generation, distribution, and transmission systems. These good practices are briefly described in this section to provide a more balanced view of PG&E's work culture, work practices, processes, and management system. Without considering these good practices, an analysis of only the OFIs would provide an unfair view of the PG&E organization's performance.

The investigation team was impressed with PG&E's efforts to understand what actually happened before, during, and after the December 8, 1998 San Francisco outage. Even though this investigation discovered a few additional facts that were not included in the report of PG&E's investigation, the majority of the data collected by PG&E is factual and thorough.

The investigation team was also very impressed by PG&E's analytical capability to analyze the instability of the system. PG&E's computer analysis of the outage is not only accurate, but also very thorough.

Also, the investigation team noticed that PG&E implemented a root cause program in 1998 which was designed to help each switching center understand the apparent causes of daily problems. The investigation team has reviewed more than 100 of the event reports issued in 1998 and found that some of them contain simple root cause analyses. While the root cause program could be improved by adding a capability to analyze human errors or underlying processes and management issues, the program is a good start in the right direction.

UNIQUENESS OF SAN FRANCISCO

The investigation team notes that the San Francisco generation, distribution, and transmission systems are different than those in other major cities. The difference is mainly a result of the location of San Francisco at the tip of a peninsula. San Francisco's transmission system is located in a narrow corridor south of San Francisco. All of San Francisco's power must flow up this narrow corridor, while other major cities receive power from corridors extending in several different directions. Also, about 50% of the San Francisco electrical load consists of networked distribution systems. Recovering loads for networks is harder than for non-networked loads (called radial loads).

Because San Francisco is special in terms of its geographic location and its generation, distribution, and transmission systems, the recommendations in this report to prevent recurrence may not be applicable to other cities. To prevent blackout events for areas other than San Francisco, area specific vulnerability analyses should be performed.

PURPOSE OF INVESTIGATION

The purpose of the investigation is to *understand the underlying root causes of the December 8, 1998 San Francisco outage, to reduce the risk of a recurrence, and to recover rapidly if a similar event occurs.*

Included in the above description of the purpose of the investigation are three key elements. They are:

- Underlying root causes
- Prevent recurrence
- Recover rapidly from any electrical outage in San Francisco

"Underlying root causes" include the human errors and equipment failures experienced during the San Francisco outage but also include process and management problems of which the human errors and equipment failures are symptoms. According to W. Edwards Deming, one of the leading experts in quality improvement, only about 10% of human errors are truly isolated human errors, not induced by deficiencies in processes or management system. Those isolated human errors are usually related to only a few specific individuals. The human errors induced by deficiencies in processes and management systems are usually pervasive throughout an organization, independent of individuals. In the case of the December 8 outage, significant human errors were made by the majority of the PG&E organizations involved in the event. Therefore, the investigation team believes that the underlying causes of the majority of these errors are deficiencies in processes and management systems.

To "prevent recurrence" means that the investigation team shall make recommendations that, if accepted by PG&E, will significantly reduce the probability of a recurrence of a San Francisco outage with a high confidence level. Based on FERC statistics, the probability of occurrence of a major prolonged outage, (defined as one that impacts more than 1,000,000 people for more than 4 hours), is once every 100 years. Regardless of the causes, San Francisco does experience a higher probability of major, prolonged outages. In the past five years, San Francisco has experienced two major, prolonged outages, which is equivalent to a rate of about one every three years The recommendations made by the investigation team are aimed at reducing the probability of major, prolonged outages by a factor of thirty or more.

To "recover rapidly from" means that if an outage similar to that which occurred on December 8, 1998 occurs in the future, service can be rapidly restored.

"Prolonged electrical outage in San Francisco" defines the type of occurrence that needs to be prevented. The investigation team's recommendations are not concerned with short, small scale outages, nor are they limited to those potential events that have the same causes as the December 8 outage, i.e., human errors in failing to remove grounds. They cover all factors under the control of PG&E that can cause major prolonged electricity outages.

ROOM FOR IMPROVEMENT

At the beginning of the investigation, the investigation team estimated the financial, health and safety impact of the San Francisco outage. This figure provides an estimate of the resources expected to prevent recurrence. In general, it is reasonable to expect a company to spend between 10 to 20 percent of the total impact to prevent recurrence.

The total financial, health and safety impact of the San Francisco outage was estimated to be between $200 million and $400 million. **Figure 6** summarizes the simple method used by the investigation team to estimate the total impact. With this estimation, the investigation team believes that it is reasonable for PG&E to spend an average of $10 to $20 million over the next few years to upgrade its work force, management systems, and electrical protection systems to prevent recurrence.

The investigation team also examined the following data to determine if there is room for future improvement.

- The trend of PG&E's System Average Interruption Duration Index (SAIDI, excluding storms, earthquakes, and the San Francisco) over the past ten years, which measures the average overall transmission and distribution system reliability
- The SAIDI (excluding storms, earthquake, and the San Francisco blackout) for other California utilities
- The switching error rates over the past four years (1995, 1996, 1997, and 1998)
- The total number of errors throughout the San Francisco outage

Figure 7 shows the trend of PG&E's SAIDI for the past ten years. As can be seen in this figure, an upward trend exists. In 1998, PG&E's SAIDI was 180 minutes, whereas the average SAIDI for other public utilities was 68 minutes. It should be noted that the 180 minutes versus 68 minutes is not an indication that PG&E is worse than other utilities. It only means that from a consumer's perspective, there is room for improvement.

Figure 8 shows the trend of the switching error rate, which was derived from dividing the switching errors by the number of switching logs operated by PG&E on a yearly basis. As can be seen in **Figure 8**, the switching error rate rose in 1998.

The investigation team counted the number of human errors of various types (grounding errors, engineering errors, operator switching errors, review errors, testing errors, maintenance errors, etc.). This analysis revealed that there were more than 140 human errors committed throughout this outage.

Based on the data discussed above, it seems that PG&E has room for improvement, especially in the area of human error reduction throughout the organization.

ESTIMATED FINANCIAL, HEALTH AND SAFETY IMPACT OF SAN FRANCISCO OUTAGE ($200 TO $400 MILLION)

Production

- **One Day Loss of Production in San Francisco (~ $200 million)***
- **Damage to or Loss of Property (~$10 million)**

Health

- **Food Contamination**
- **Medication Problems**
- **Health Emergency Administration Problems**
- **Anxiety**

Safety

- **Traffic Accidents**
- **Accidents Due to Visibility Problems**

*Loss= State Domestic Product Per Year / 200 Working Days Per Year / Number of Employed in State * People Affected * 65% * One Day
= $960 billion per year /200 working days per year /15.6 million Employed * One million * 0.65
= $200 million
65% of affected in San Francisco Area are assumed to perform work during weekdays
It is assumed that every person affected lost $10 worth of food or other properties (such as computer information)
The maximum health and safety impact is assumed to be of the same magnitude as that resulting from production loss.

Figure 6

PG&E System Average Interruption Duration Index (major disasters excluded) and 3-Year Rolling Average

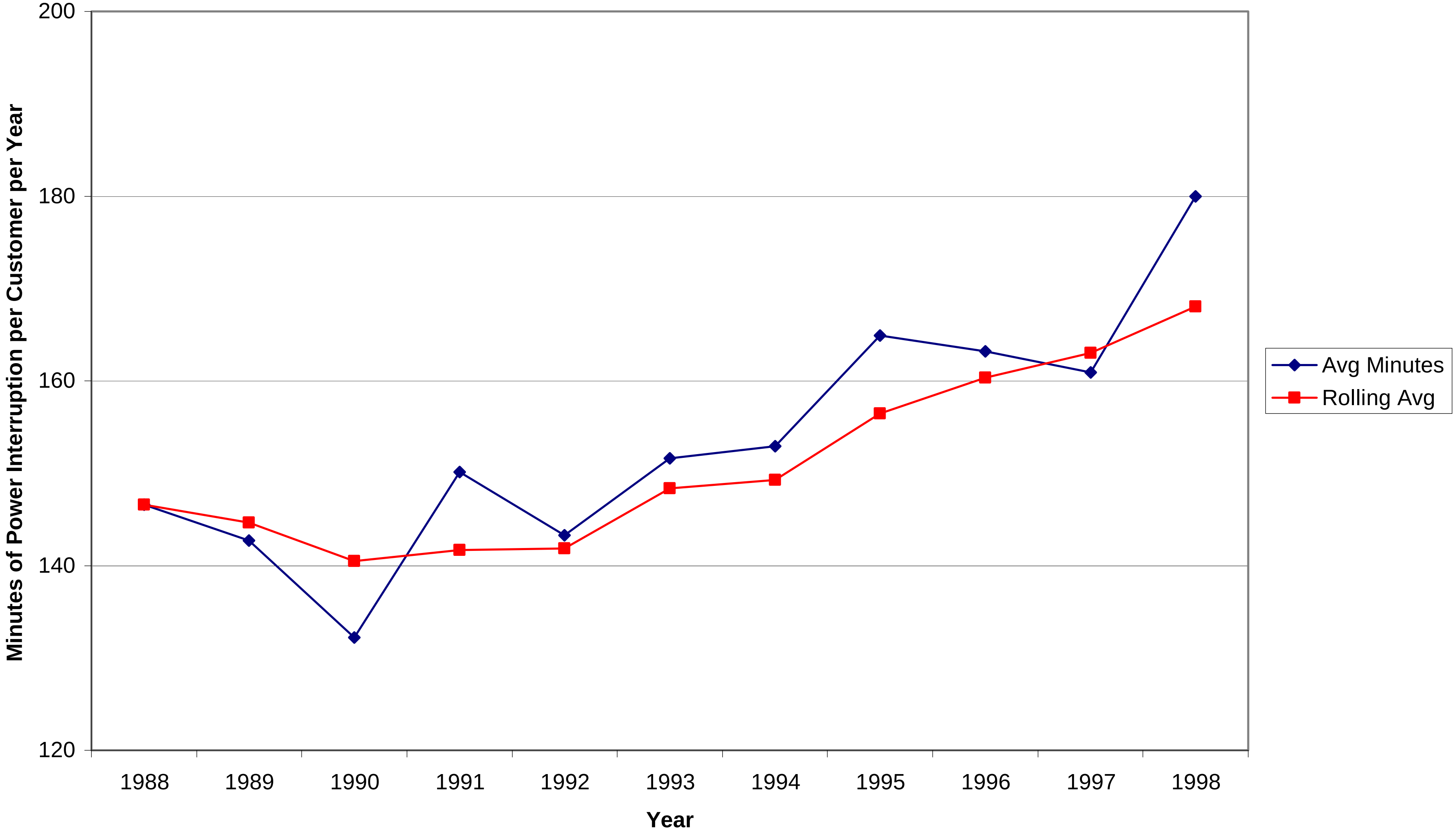


Figure 7

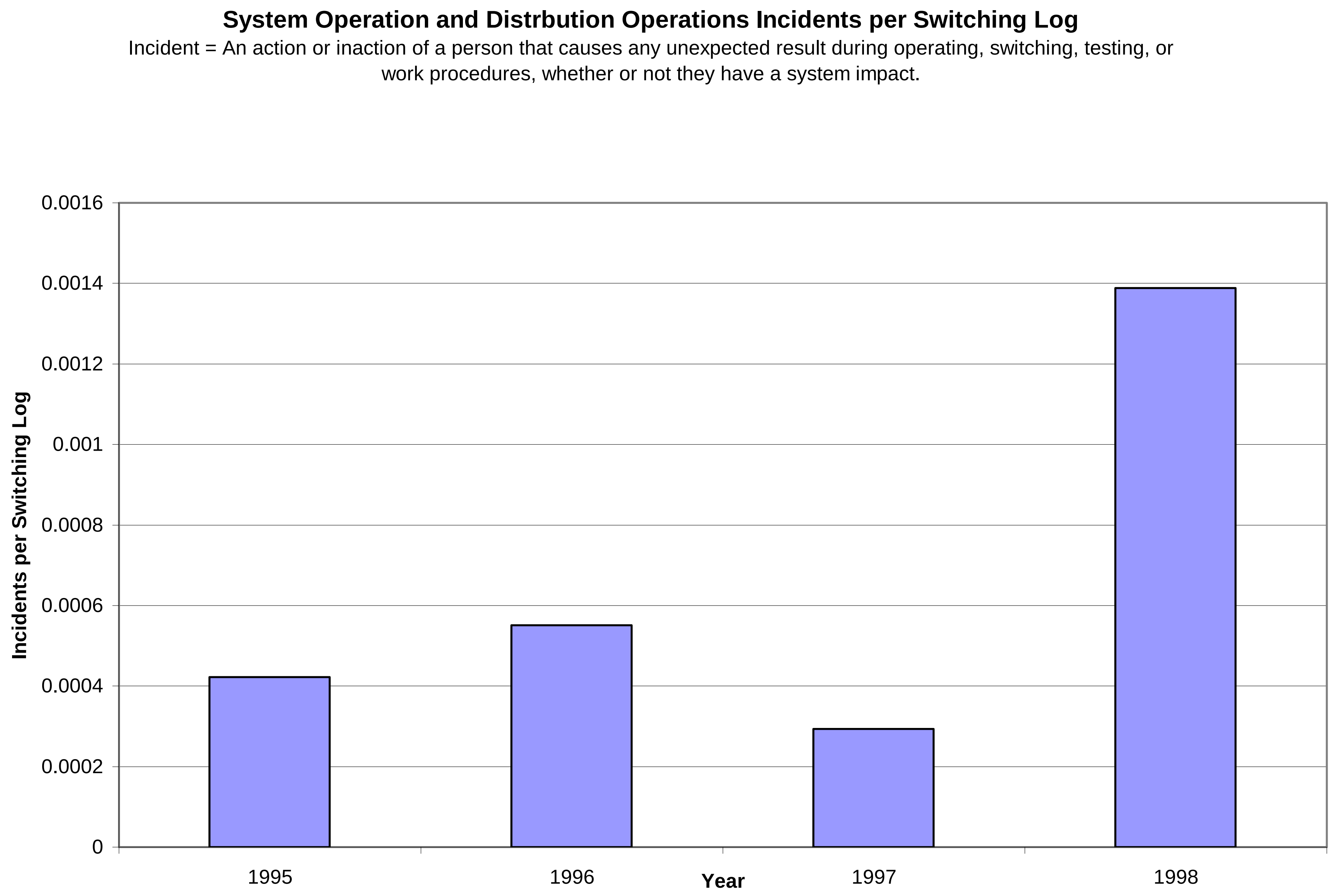

System Operation and Distrbution Operations Incidents per Switching Log
Incident = An action or inaction of a person that causes any unexpected result during operating, switching, testing, or work procedures, whether or not they have a system impact.
Incidents per Switching Log
0.0016
0.0014
0.0012
0.001
0.0008
0.0006
0.0004
0.0002
0
1995
1996
1997
1998
Year

Figure 8

PROCESS OF INVESTIGATION

Figure 9 illustrates the six-step investigation process. The investigation process has four characteristics:

- A forward looking process to identify OFIs and the actions to improve or correct them, as opposed to an audit assessment that focuses on who and what failed to comply with procedures and regulations
- A full scope investigation process, which analyzes existing work practices, processes, and management to identify opportunities for improvement
- An integrated process to examine OFIs in the three areas of electricity generation, distribution, and transmission
- An independent process that is not influenced by interests of the parties involved in the outage

The investigation process begins by collecting the following data:

(1) Sequence of event data (most of which were presented in PG&E's root cause analysis report)
(2) Past similar occurrences and implemented corrective actions
(3) Existing work practices, processes, and management expectations
(4) Human errors and equipment failures

The second step in the investigation is to validate the data collected. The validation is performed with a consistency check. Any data, before it is used to help reach a conclusion, has to be consistent with:

(1) Expectations of the investigators in terms of its value, form, reasonableness or usage
(2) Other references to the data from totally independent sources

The third step is to identify human error inducers and broken barriers that are designed to prevent a human error from causing an event. Note that human errors are made frequently and can not be totally avoided. However, by setting up barriers, human errors can be contained so that they will not cause any event. For example, a worker may make an error in failing to open a valve that was needed to transfer water to a boiler before it heated up. Without the water, the boiler could melt down in a few minutes. However, if the error was detected by his supervisor and the valve was opened in a timely manner before the boiler heated up, no event would occur. The barrier to prevent a human error (failure to open a valve) from causing an event (boiler meltdown) was the supervisory review and verification of activities performed by the worker.

A FULL SCOPE INVESTIGATION PROCESS

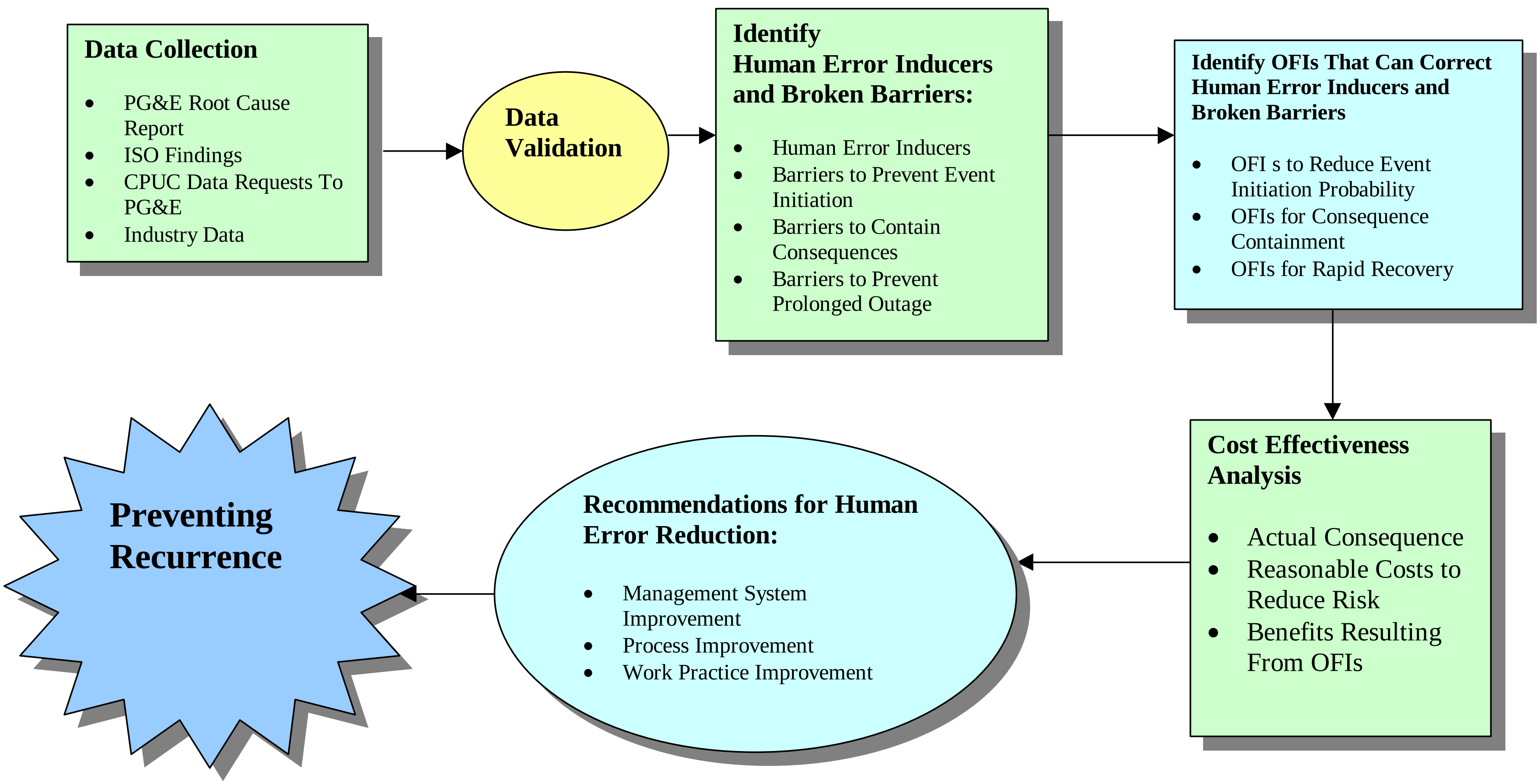


Figure 9

Figure 10 shows the human error inducers, which are divided into either internal or external factors. In general, both internal factors and external factors can induce human errors. Internal factors, such as illness and careless personality, are specific to individuals. External factors, such as vague or incorrect orders or procedures, distractions, etc., are not specific to individuals. Workers can make similar types of errors when they are induced by the same external factors. The underlying causes of external factors are inadequate work processes and/or inadequate management systems. For example, vague instructions in procedures (such as using the word recommended versus required) may induce errors and events. The underlying cause of vague instructions might be failure to train procedure writers to write human error proof procedures. Inadequate training is a management issue.

The fourth step is to identify Opportunities for Improvements (OFIs) that can cost effectively eliminate human error inducers and strengthen broken barriers. The OFIs do not necessarily indicate deficiencies or substandard practices relative to other similar utility companies. OFIs , if not corrected, will result in the recurrence of events similar to the December 8, 1998 San Francisco outage.

The fifth step is to formulate recommendations (improvements) that address the identified OFIs and to do a simple cost effectiveness analysis. Only those OFIs that can be cost effectively improved are examined further for detailed corrective actions.

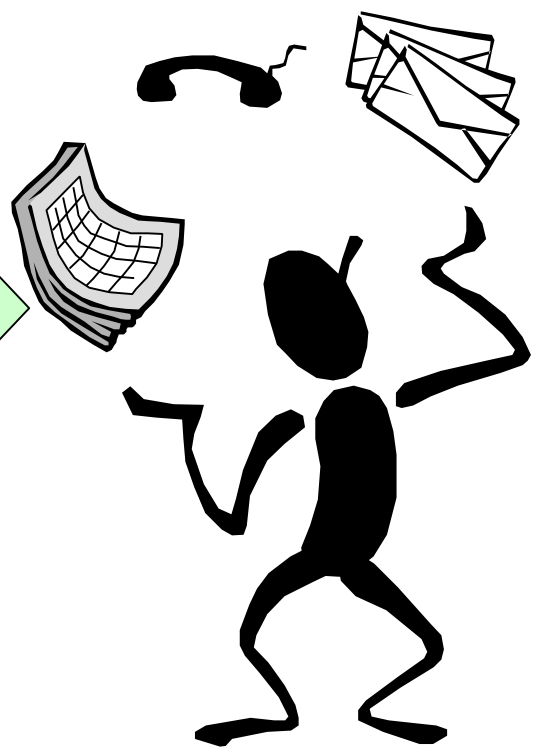
The sixth step is to select recommended improvements that are considered by the investigation team to be the most cost effective in reducing the total risk of recurrence.

HUMAN ERRORS (SYMPTOMS) ARE INDUCED BY INTERNAL AND EXTERNAL FACTORS AND THEIR UNDERLYING CAUSES

INTERNAL FACTORS (~10%)

(1) Illness (such as Attention Deficit Disorder)
(2) Careless personality

Internal factor induced human errors are made by a few individuals who have higher error rates



EXTERNAL FACTORS (~90%)

External factor induced errors are prevalent, independent of individuals

(1) Vague or incorrect guidance, orders, or procedures
(2) Distractions
(3) Over-confidence inducers
(4) First day after days off
(5) Work stress
(6) Working with low alertness
(7) Infrequent evolutions w/o adequate training
(8) Burdensome work requirements
(9) Time pressure
(10) Inadequate communication channels

Underlying Causes Are Inadequate Processes and/or Management Systems

Figure 10

DATA VALIDATION

The second step of the investigation process is to validate critical data. Critical data is defined by the investigation team as the data that, if invalidated, will change the investigation conclusion significantly.

In general, the sequence of event data reported in PG&E's investigation report is factual. However, the investigation team found that there was an inconsistency between what was stated in the PG&E report and what was believed to actually occur. That is, the investigation team believes that the handwritten step in the switching log was added into the log after the event, not before the event as reported in PG&E's report. **Figure 11** describes the differences in what PG&E reported and what the investigation team believes to have occurred regarding the handwritten step in the switching log.

Figure 12 shows the first page of the switching log and a close view of the handwriting in the switching log. As can be seen in these two figures, it is obvious that the writing instrument (and/or the writing style) that was used to write the time 0813 (time of cutting in the relay) was the same as the one used for writing the step into the switching log. This means that the step was not written during the switching log preparation. Had the step been written in during the preparation of the switching log, the writing instrument and handwriting associated with the time of 0813 would have been consistent with those of the other times.

Figure 13 shows the differences between what PG&E reported and what the investigation team found. In essence, the investigation team invalidates the reported data regarding switching log preparation and operation activities.

INVALIDATION OF REPORTED SWITCHING LOG ACTIVITIES

PG&E REPORTED….

Operator Used Computer Document (Stored Reference Material) to Prepare Switching Log SAM 98-840.

→ Because the Computer Document Did Not Require the Differential Relay be Cut In, a Single Step Was Handwritten Into the Log.

→ The Switching Log Was Checked and Reviewed by a Reviewer at the San Mateo Switching Center.

→ The Operator Performed All Steps, But Missed the Relay Cut-in Step Due To Inattention and Single Step (as opposed to four steps).

THE INVESTIGATION TEAM BELIEVES…

Operator Used Computer Document (Stored Reference Material) to Prepare Switching Log SAM 98-840.

→ Because the Computer Document Did Not Require Differential Relay be Cut In, the Switching Log Missed the Cut-in Step.

→ The Switching Log Was Checked and Reviewed by a Reviewer at the San Mateo Switching Center. The Missed Step Was Not Detected or Added in.

→ Event Occurred Resulted From Operator Errors

→ Switching Log Was Altered By Operator With a Handwritten Step to Make the Switching Log Look Correct.

Figure 11

1	CREW	REPORTS	OFF THE	#2 115 KV BUS #2 SECT D, ALL MEN AND GRDS IN THE CLEAR READY TO RESTORE BUS NORMAL EXCEPT THAT 657,658 WILL REMAIN OPEN TAGGED MOL	0810	[redacted]	0810	[redacted]
2	SAN MATEO	CHK	622	OPEN IN YARD	0800		0806	
3	"	RT/CLOSE	623	CC&L			0808	
4	"	CHK	402	OPEN IN YARD			0810	
5	"	CHK	401	CLOSED IN YARD			0811	
6	"	RT/CLOSE	403	CC&L			0812	
7	"	RT/CLOSE	SECT D	# 2-115KV BUS POTS(3 PHASE KNIFE BLADE)			0819	
8	"	Chk CHK	# 2 115KV [illegible] 402	Bus Diff Rly SCADA C/OUT			0813 0814	
9	"	CHK	402	BREAKER FAILURE C/IN			0814	
10	"	CHK	402	SEL SW DEV # 121/187N-BPD IF ON OFF POS			0815	
11	"	CHK	402	SEL SW DEV # 121/187NBU-BPD IF ON OFF POS			0815	
12	"	RT/CLOSE	402	C/CLOSED ENERGIZING # 2-115KV BUS SECT D			0816	
13	"	PLACE	SECT D	115KV BUSS DIFF SEL SW ON POS 2				
14	"	TEST	SECT D	ALL LAMPS LIT IN 115KV BUS DIFF CAB				

(13) SWITCHING PREPARED BY

(15) SWITCHING CHECKED BY

(16) SWITCHING 7/?2

A FEW THOUGHTS ON TWO HUMAN ERRORS PG&E REPORTED AS CAUSES OF THE OUTAGE…

	PG&E Reported…	The Investigation Team Believes…
Failure to Remove Ground	The immediate cause of this event was the failure of the transmission station construction crew to remove and account for all protective grounds…several causal factors work together… (Page 1-8, PG&E Report)	The major underlying cause are inadequate procedure development process and weak management's control of human performance in the field that induced the human errors which led to the failure to remove grounds.
Failure to Follow Switching Log	At 0710…a single line item was handwritten by the operator into the switching log to cut-in the differential relay protection scheme…reviewed and checked... At 0806, operators personnel started switching in accordance with switching log SAM 98-840. The handwritten step…was noted as have been performed at 0813. (Page 1-7, PG&E Report)	The handwritten step was written after, not before, the event, to make the log look correct. The actual cause of failure to cut in the relay was related to poor preparation of the switching log, missing the relay cut-in steps completely.

Figure 13

EVENT INITIATION PHASE

This phase covers the human errors involving ground removal that contributed to the initiation of the electrical fault at the San Mateo substation. Based on the data examined by the investigation team, the two underlying causes that contributed to the initiation of the event were error prone procedures and human error prone work practices. Based on the fact that there are many human error traps, such as vague instructions, in the procedures (e.g., Grounding Manual), some human errors are inevitable in the execution of the procedure. Therefore, both the error proneness of the procedure and work practices contributed to the failure to remove grounds.

Figure 14 shows how a human error involved in the failure to remove grounds can result in an electrical fault. It has to penetrate three barriers. These three barriers are:

- Supervisory review and verification
- Independent review and verification
- Post work testing

The OFIs that can be corrected to reduce the probability of initiating electrical faults due to inadequate ground removal are:

- Inadequate supervisory skills to command and control field work (OFI-1)
- Error prone work culture that tends to bypass procedures and work practice requirements (OFI-2)
- Lack of a positive means to track and count grounds installed and removed (OFI-3)
- Inadequate independent review process to verify field work (OFI-4)
- Inadequate post-work testing procedure that allowed the electrical bus to return to service before finding unremoved grounds (OFI-5).
- Inadequate attention to critical operation and critical equipment (OFI-6)

EVENT INITIATION BY HUMAN ERRORS INVOLVING FAILURE TO REMOVE GROUNDS

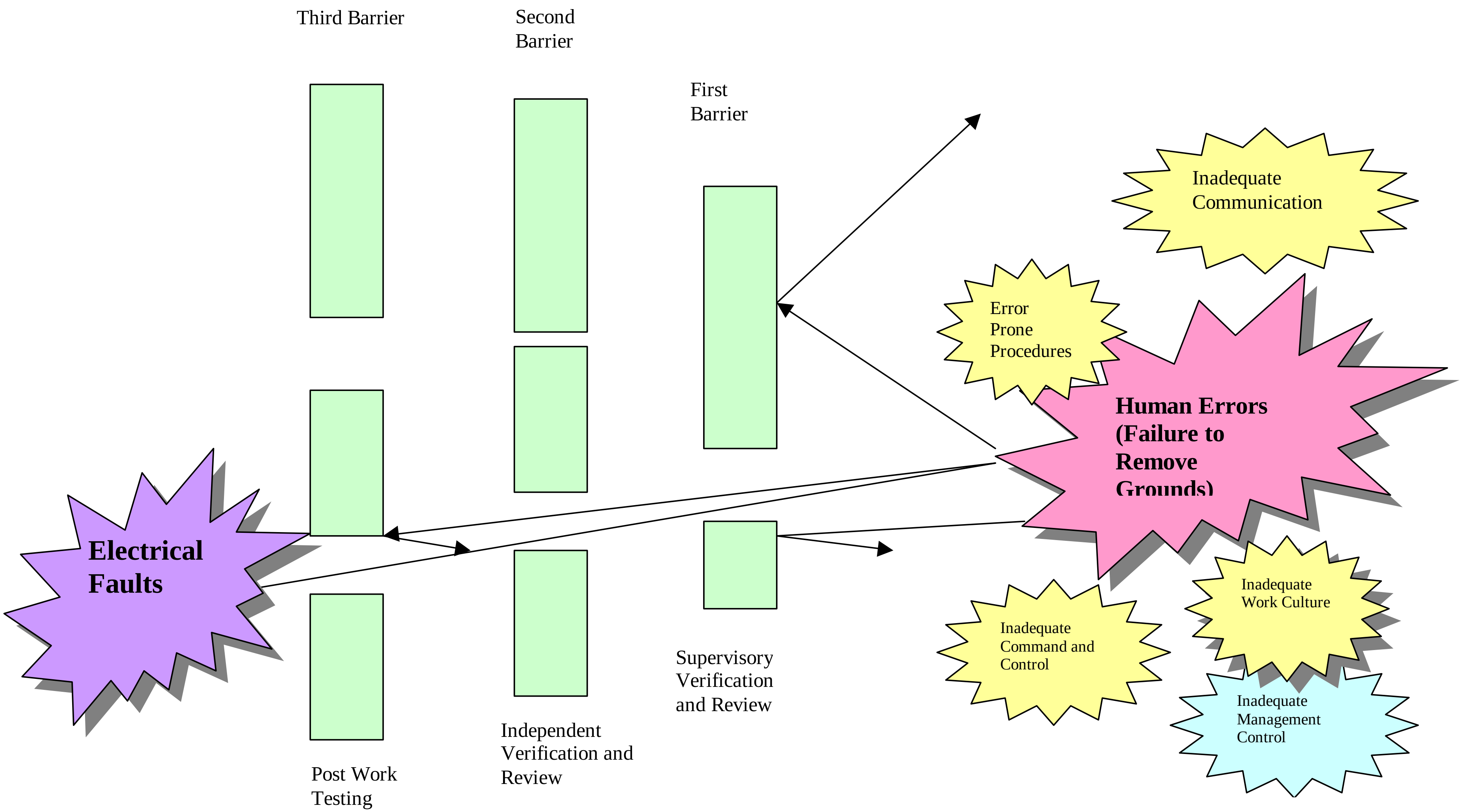


Figure 14

OFI-1 INADEQUATE SUPERVISION TO COMMAND AND CONTROL FIELD WORK

The work practices associated with the ground removal activities on December 4, 1998 and with the reporting off the clearance on December 8, 1998 contributed to leaving some protective grounds installed. Inadequate supervision contributed to the human errors made on December 4 and 8, 1998.

Based on PG&E's interview data, the investigation team found that the following are some examples in which weak supervision contributed to the failure to remove grounds from the bus:

- The subforeman on December 4, 1998 did not think he mentioned the use of observers to the crewmembers - he felt they had been trained and knew how to do it on their own. As mentioned above, two crewmembers had no grounding training.

- The focus of the entire crew on December 4, 1998 appeared to be on collecting 18 grounds for the job at Cooley Landing, rather than satisfying the requirement for removing the 15 grounds necessary for reporting off the Bus 2 clearance. Through the errors of tunnel vision and not considering the whole situation or viable options, the subforeman created a mindset in the crew that was established at the morning tailboard and was perpetuated throughout the day. The subforeman did not keep himself or his crew focused on the primary task at hand - removing the grounds from Bus 2 Section D in preparation for reporting off the clearance. The big picture was lost and the crew did not function as a team.

- The subforeman failed to perform a complete walk-down of the equipment prior to reporting off clearance on December 8, 1998. Although this was not a requirement, it is a normal practice for the subforeman and a normal practice of clearance holders in substations. This departure from the normally accepted standards was probably due in part to a recollection of misleading conversations on Friday (December 4), that "all grounds had been collected", that Tuesday, December 8, 1998, was the first day back after three days away from the job, and that the foreman did not effectively recap the situation before proceeding. To reduce human errors after days off from a job, supervisors usually use "recap" meetings to go over what has been done, the status of the work, and the plan for the future. In the auto industry, this type of "recap" meeting significantly reduced the problems with poor quality found in work done on Monday mornings (called the Monday morning lemon problem).

- On December 4, the subforeman was only present at the work site directing activities for approximately three hours. Over three hours were spent at his desk in preparation for the Cooley Landing job and approximately three hours were spent on two trips to Cooley Landing. This lack of presence and preoccupation with other activities diminished his effectiveness in providing the guidance, coaching, and field surveillance required of an effective supervisor.

- On the two occasions that the subforeman was away from the job site he did not clearly put anyone in charge. This apparently contributed to a lack of coordination and oversight of crew activities, and resulted in an individual rather than in a team effort.

- When the subforeman assigned two crewmen to help remove grounds, it appears that he did not question the qualification of either of the two crewmen and was not specific in his assignment. Neither crewman was ground qualified. The crewmen apparently did not question the assignment—each subsequently removed two grounds each. One believed it was okay to remove grounds, but not install them.

- A crewman was removing grounds at the T-Tap (with four down and two to go) when the ground collecting crewman stopped by. The ground collecting crewman commented that the T-Tap grounds were supposed to stay up. The crewman removing the grounds responded that they were down now. He removed the remaining two grounds and left to secure a line at Bank 5. The ground collecting crewman continued collecting grounds. When the foreman returned from a trip to Cooley Landing, he instructed the ground collecting crewman to replace the T-Tap grounds. The T-Tap grounds were not replaced until later that day when, at the final gathering of the crewmen at the end of the work day, the subforeman inquired if they had been replaced. These actions would suggest a lack of a self critical attitude indicative of an error prone work culture.

- Although the reconductoring work was completed on Friday, December 4, the clearance was not reported off until Tuesday, December 8. Not clearing off the bus on Friday after the reconductoring work was completed, as would normally have been the procedure, more than likely shifted the focus of the subforeman from that of removing grounds “to report off the clearance,” to removing grounds “for the Cooley Landing work.” In addition, a “first-day back” condition was created on Tuesday, December 8, when the crew returned to the job four days later and the existing conditions were not reviewed. The following conditions possibly contributed to the delay in reporting off:

    * Conversations between the subforeman and the operators during the week before the grounds were removed indicated that operations thought it would be better for the subforeman to report off the

following week on Tuesday, rather than the previous Friday. The subforeman said he would rather have reported off on Friday evening as would normally be the practice—reporting off in a timely manner after the work is completed. This could very well have set the stage for the mindset to gather grounds for Cooley Landing rather than to report off the clearance.

* In discussions with the Foreman, operators said that if you report off early it costs us points—fines are involved, they're not going to let us report off early.

* The subforeman told operations that he would be completing his work on Bus 2 on Friday, December 4, and asked if they wanted him to clear off on Friday or the following week. He had been asked when the work would be completed and returned to service several times since reporting on the clearance. The ISO wanted the bus back as soon as possible. However, operations stated they wanted the bus back the following week, but gave no reason.

* The Foreman didn't know that the subforeman was not clearing off Friday - he said that t was normal to report off when grounds are removed. Yet, there is no evidence that the Foreman questioned the subforeman about not reporting off Friday.

- Additional grounds were found to be available at another substation, yet they were not used. This viable option was available, and with proper planning could have been used for the Cooley Landing work. This could possibly have eliminated or reduced the distractions caused by collecting the grounds at San Mateo and allowed the crew to focus on the task at hand--returning Bus 2 to service. The Foreman knew the grounds were available, but did not know or question why they were not used.

- The supply of grounds available to the crew may have been a contributing factor, in that there did not appear to have been a sufficient number of grounds available for use in the department to support the numerous ongoing substation activities at that time. This could present an unnecessary planning concern in juggling the use and availability of grounds from one job to another that could result in distractions, preoccupation with unnecessary tasks, or time pressures. The second level supervisor feels that there is a shortage of grounds in the system, but with proper planning, they can be obtained from other locations.

- Both the grounding stick-end clamps and the cable-end clamps of the ground devices remaining on the bus were connected about 20 feet above the yard level and thus were not clearly visible as most protective grounds are. This condition may have been worsened when the ground tails were reportedly tied up high on a grade beam. Because of this, an opportunity for improved performance was possibly lost, as the tails were less likely to be spotted. Several opportunities presented themselves on December 4, 1998 during ground collection activities, on December 4, 1998 when testing Switch 659, and during the activities involved for returning the bus to service.

OFI-2 ERROR PRONE WORK CULTURE THAT TENDS TO BYPASS PROCEDURES AND WORK PRACTICE REQUIREMENTS

The investigation team believes that PG&E did not always ensure that the procedures and standards that supported crew grounding activities were clear and consistently used. Only clear and consistent standards can lead to the expected level of performance—specifically, the use of grounding observers, conducting a specific grounding tailboard, the use of the Grounding Tail Board Form, and the use of the Tailboard Checklist. .

The administrative control contained in the Protective Grounding Manual specifically requires the counting of protective grounds upon installation and removal. Furthermore, it specifies that the person in charge shall designate an observer to comply with Standard E-TS-S007, Grounding Observers for Grid M&C. The Standard in part required:…that the person in charge (subforeman in this case) appoints a qualified observer whose sole purpose is to direct the application and removal of protective grounds, that a separate grounding tailboard be held, and that the observer utilize the Grounding Tailboard Form covering all information contained on the form.

Inconsistent use and non-adherence of procedures and standards appeared to be present to some degree during initial grounding on November 12, 1998, and was pervasive during ground removal activities on December 4, 1998. This was apparently due in part to a crew culture that did not question the lack of procedural adherence, to crew members that did not know the procedures existed, and to confusion existing in the need for use of items such as the grounding form and checklist in which case the non-conservative approach was taken and neither was used.

The following are a few examples of inconsistencies in procedural use and adherence:

- On November 12, 1998 prior to ground installation on Bus 2, a detailed walk-down of the clearance was conducted by the subforeman and attended by the foreman; however, the grounding tailboard form was not used. There is no evidence that an observer was designated for ground installation; however, in most cases the crew assumed this to be the foreman.

- The tailboard grounding form was not used on December 4, 1998 during the morning tailboard (or any other time throughout the day during grounding activities). From PG&E's interview notes, the investigation team discovered the following:

    * The foreman said that its use was never enforced.

    * The subforeman said that the foreman had never discussed its use with him and had never seen E-TS-S007.

* The subforeman said that it was something new (although the Grounding Observers for Grid M&C, E-TS S007 Rev 1, effective date was September 1997); he was not familiar with it and had not used it.

* In addition, the ground qualified crewmembers at the tailboard had never seen the grounding form.

The Grounding Tailboard Form requires the recording of information pertinent to the grounding process, including the number of grounds installed and removed. This opportunity was lost by its non-use.

- The Tailboard Conference Checklist was not used on December 4, 1998 during the morning tailboard. The "checklist" is more generic than the Tailboard Grounding Form and provides reminders relating to specific grounding requirements and general safety requirements. The investigation team believes that the following factors contributed to its lack of use:

    * There was confusion on the expectation for its use, even though management had desired to make its use mandatory.

    * The foreman believed that the format of the tailboards followed the document and was more elaborate.

    * The foreman apparently had not discussed the use of the checklist with the subforeman.

    * The subforeman claims that he had never really used the checklist and was not aware of it.

    * The ground qualified crewmembers were not aware of the checklist.

    * The foreman did not think that the grounding manual and standards were clear; he felt they were confusing and provided some misinformation.

    * All ground qualified members of the crew had not received instruction on E-TS-S007.

- The subforeman did not designate the required grounding observer(s) at the morning tailboard on December 4, 1998. An observer's sole purpose is to watch and direct the application and removal of grounds. The observer would have ensured that all information required by the Grounding Tailboard Form was covered in detail at the grounding tailboard and would have documented such things as structures, clearance points, and, most importantly, the number of grounds removed and installed (PG&E Investigation Report, Sec 3.4.1). The following may have contributed to the confusion in the specific identification of an observer during grounding activities:

* Some crewmembers assumed that the subforeman was acting as the observer, which was typical for this crew. However, the subforeman was focused on other areas and not personally directing the removal of all grounds.

* Two crew members, with no ground training, removed grounds - they were directed to do so by the subforeman and said he was watching. One had been told that it was okay to remove grounds, but not install them.

* One crewmember, when asked about the need for an observer, said that normally the whole crew was present when pulling grounds. On this day, there appeared to be many activities in progress and the crew, for the most part, was dispersed with each member performing his individual assignment with little interchange of information.

OFI-3 LACK OF A POSITIVE MEANS TO TRACK AND COUNT GROUNDS INSTALLED AND REMOVED

The investigation team found that the failure to remove grounds that occurred on December 8, 1998 is just the latest incident of grounds being forgotten and left on when a bus was energized at PG&E. The investigation team found three similar incidents that also occurred at PG&E. These three incidents are:

(1) There was a grounding error at PG&E's Diablo Canyon Nuclear Power Plant on October 21,1995, which caused a transformer explosion that cost well over one million dollars to repair. The plant was shut down and stayed down for more than three months as a result of this failure to remove grounds.

(2) One of the emergency diesels at the Diablo Canyon Nuclear Power Plant was started into a set of grounds in 1995.

(3) On July 29, 1997, while preparing the Pittsburg substation to be switched back into service, a set of three-phase grounds were overlooked. The switchman closed the high side bank switch (60KV) to energize the transformer bank.

PG&E recognized past grounding problems and the importance of tracking and counting grounds. PG&E states in the Grounding Manual that grounds need to be counted when they are put up and counted when they are taken down. There is a grounding tailboard form that provides spaces to enter the number of grounds put up and the number taken down. E-mails have been sent out stating the necessity of these forms.

The investigation team believes that keeping track of personal grounds should have more than one level of accountability. One method of providing another level of accountability for attached grounds in stations would be for operators to "pin" all grounded points on their mimic boards. The mimic boards and pins are the operators' way of knowing the configuration of their stations. Grounds attached to a normally energized section of the station , even within clearance points, is definitely a configuration change for that station.

The investigation team also believes that there should be one caution tag on each set of grounds installed in the station. The caution tags could be numbered to meet the counting requirements stated in the grounding procedures.

The caution tags in electric substations should be treated similarly to "man-on-line" tags (for control purposes only). They would be held in the control room and not removed from the control room until the tag was removed from the physical equipment.

RECOMMENDATION ON OFI-3

It is recommended that PG&E institute a tagging and pinning practice to track the installation and removal of grounds. (Recommendation OFI-3.1)

It is recommended that PG&E institute a program that makes the ground cables, rods, or other ground devises more visible (such as a highly visible color, reflective tapes for easy identification in the evening). (Recommendation OFI-3.2)

OFI – 4 INADEQUATE POST-WORK TESTING PROCEDURE

General, post-work tests are required and performed to ensure functionality of a major component after repair, modification, overhaul, or changes in configuration. As can be seen in **Figure 14**, testing is the third barrier to prevent a human error from becoming an event.

The post-work tests are usually required for bus after reconductoring work (i.e., change the size of the bus). The main purpose of the post-work tests on buses is to ensure that there are no unintended grounds (such as mis-position of equipment, unremoved grounds, etc.).

Currently, PG&E's test program does not require post-work tests after bus reconductoring. As such, no post-work tests were performed on Bus 2, Section D before it returned to service after reconductoring. Had post-work tests been performed, unremoved grounds would have been identified and removed before Bus 2, Section D returned to service.

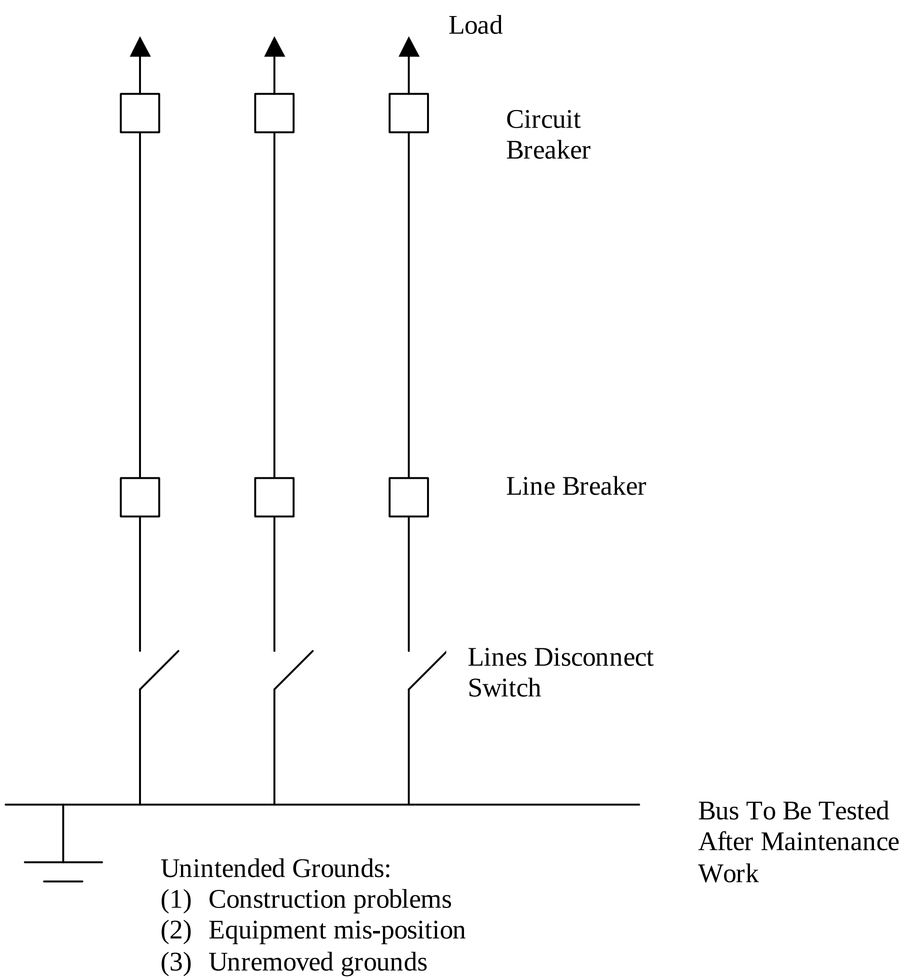
Figure 15 shows a sample test plan that has been used by other utilities to perform post-work tests after bus reconductoring. This plan uses a proven circuit breaker (i.e., a breaker to which has no work has been performed since previous tests) and a source of power from a lightly loaded line. By bringing in the voltage from the lightly loaded line, the bus can be tested using the remote circuit breaker as its protection system. If the circuit breaker trips, it indicates that there is an unintended ground on the bus. Otherwise, the bus is free of unintended grounds.

RECOMMENDATION ON OFI-4

It is recommended that PG&E revise its post-work test program to include tests after bus work. The test plan should be prepared according to the extensiveness and the type of bus work. (Recommendation OFI-4.1)

Moreover, it is recommended that PG&E review its test program to ensure there were no other exceptions that, if allowed, could lead to unexpected equipment failures. (Recommendation OFI-4.2)

BUS TESTING STRATEGY (AN EXAMPLE) TO DETECT UNINTENDED GROUNDS



How is a Bus Tested After Work?

(1) Select a lightly loaded line in which the circuit breaker is proven to work from a previous test.
(2) Trip the circuit breaker in the lightly loaded line.
(3) Close line disconnect Switch.
(4) Close line breaker to energize the line.
(5) If there are unintended grounds on the bus, the circuit breaker will trip off.

Figure 15

OFI-5 INADEQUATE ATTENTION TO CRITICAL OPERATION

In general, a critical operation that, if not correctly executed, may lead to significant consequence, is treated with special attention. For example, operation instruction or warnings of a critical switch is often displayed near the switch. Here are a few examples of critical operation:

- Any operation or component that can damage a space shuttle is singled out with a special classification (level 1 component). Critical operations have automatic interlocks to prevent unintended incorrect operation due to human errors so that unintended human errors can not destroy the equipment.
- At a nuclear power plant, any operation or component that can lead to the defeat of an emergency cooling system is called a safety-related operation or component. All safety related operations must be proceduralized and reviewed. All safety related components have to be maintained with a higher frequency. Deferring of maintenance of critical components is not allowed.

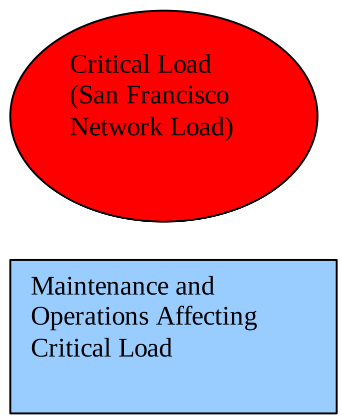
San Francisco load is very critical. Any switching operation(s) or equipment in which a single failure (one human error or one equipment failure) or two failures (two human errors, two equipment failures, or a human error plus an equipment failure) could cause the loss of San Francisco critical load, should be designated as critical equipment or critical operation.

The critical equipment and critical operation should be treated with special attention. **Figure 16** illustrates the critical equipment and operation concept. The following should be performed for critical equipment or critical operation:

- Critical operation should only be performed in a specified operation window so that, if San Francisco loses its load, the financial, health, and safety impact is kept to a minimum. For example, critical switching at San Mateo (or Martin) substation that may lead to a San Francisco blackout should be performed in operation windows when San Francisco load is off peak. For example, had the switching (closing the tie breaker 402 on the morning of Tuesday, December 8) been performed on Sunday morning, when the load is low, the system fluctuations would have been small enough that the San Francisco outage could have been avoided. **Figure 17** illustrates a typical correlation between electrical system instability and load. At off-peak hours, the electrical system is inherently more stable. Therefore, a small disturbance may not result in electrical system instability.

- Critical operations should be independently audited at least once a year to identify areas that need to be improved.

CRITICAL EQUIPMENT AND OPERATION CONCEPT



- Special Audits
- Higher Maintenance Requirements
- No Deferred Maintenance
- Switching Window to Minimize Potential Impact
  (Holidays & Off-peak Time)

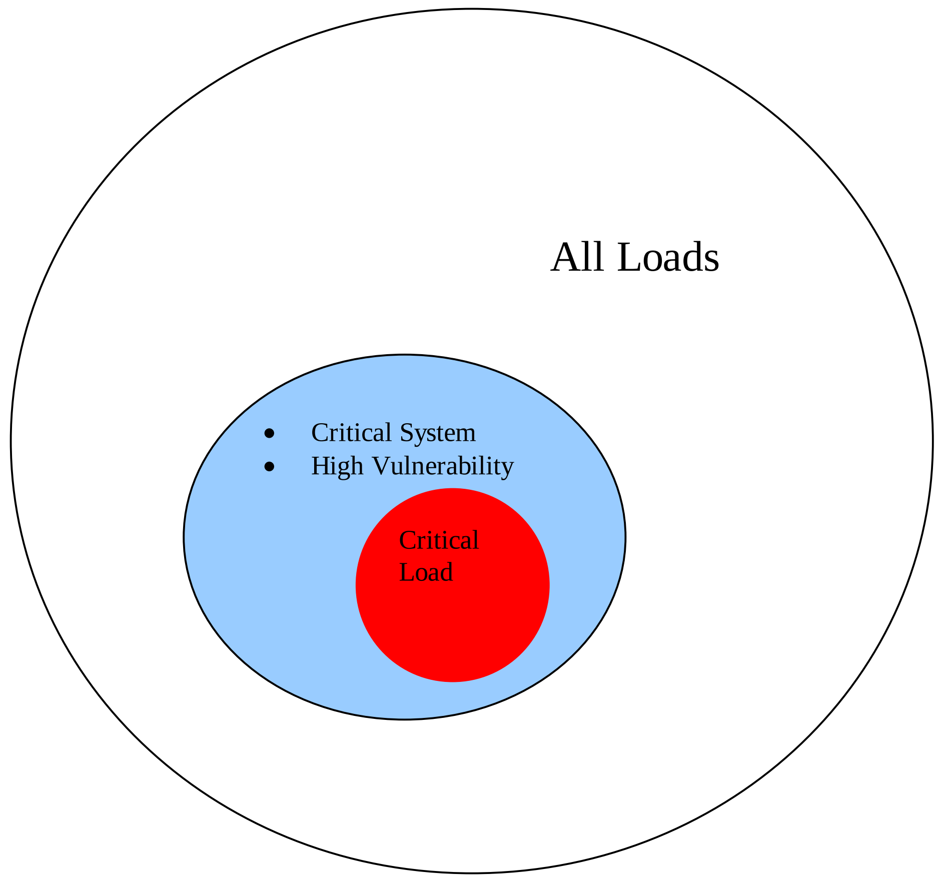


Figure 16

TYPICAL IMPACT OF ELECTRICAL LOAD ON SYSTEM STABILITY INDUCED BY FAULTS

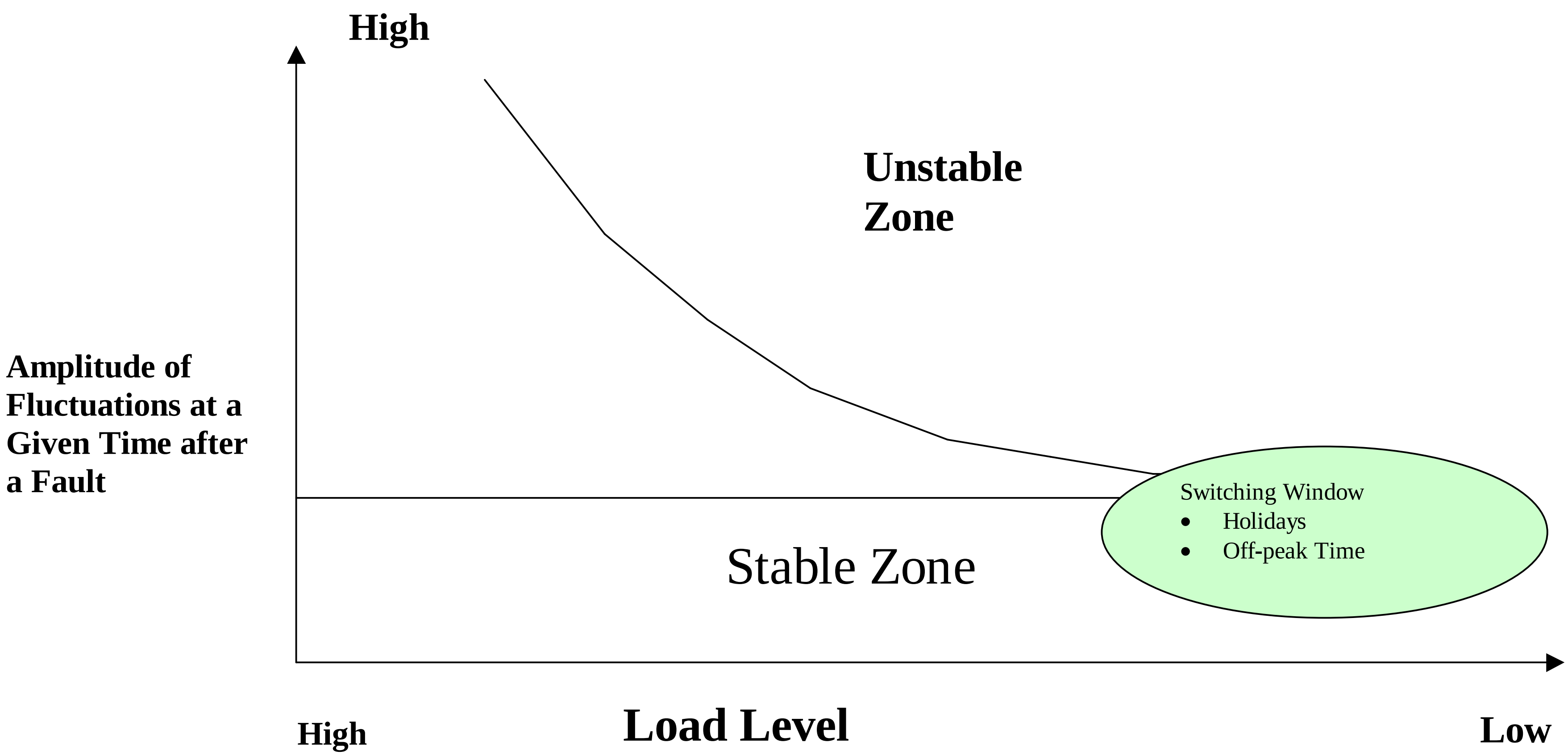


Figure 17

- The maintenance requirements for critical equipment should be higher than the non-critical equipment to ensure that higher reliability is achieved. The requirements include, but are not limited to:

    - Frequency of preventive maintenance
    - Use of condition monitoring to detect incipient failures
    - Procurement standards
    - Receipt inspection
    - Functionality testing before delivery

- Failures of critical equipment or switching errors involving critical equipment should be analyzed for root causes and cost-effective corrective actions should be implemented.

RECOMMENDATION ON OFI-5

It is recommended that PG&E establish a critical equipment and operation program (CE&O Program) that identifies critical operations and critical equipment which, if a failure occurs, can result in a loss of San Francisco critical load. Within this program, special operations and maintenance requirements should be established to help enhance the reliability of human and equipment performance (Recommendation OFI-5.1).

It is recommended that PG&E establish a special audit program to audit the human performance of critical operations on a yearly basis. Through the audits, non-compliance rates (such as actions that do not comply with the existing requirements) of critical operations should be compiled and trended. (Recommendation OFI-5.2)

It is recommended that PG&E analyze failures of critical switching operations or critical equipment for the root causes and implement cost-effective corrective actions to prevent recurrence. (Recommendation OFI-5.3)

It is recommended that PG&E establish a switching window policy so that all critical switching that may cause severe system disturbance in the event of equipment failures or human errors, should be performed within the off-peak switching window. (Recommendation OFI-5.4)

CONSEQUENCE CONTAINMENT PHASE

This phase covers the period from the time when the fault was initiated at the San Mateo substation to the time when the San Francisco electrical load was tripped off. After the initiation of a fault, there are local and distant protection systems designed to contain the consequences of the electrical fault. If these local and distant protection systems fail, the San Francisco Operating Criteria (SFOC) is designed, as a last defense, to isolate the San Francisco electrical system and preserve its critical load. The isolation ensures that the critical load be served by Potrero and Hunters Point power plants, which are located within the San Francisco area.

After initiation, the consequences of a fault are contained by three barriers. These three barriers are:

- Local clearing with primary protective relays (such as differential relay for bus)
- Distant clearing with Zone 2 relays which stop the faults at a distant substation
- A separation system to preserve critical load (such as the San Francisco Operating Criteria to preserve the network load in downtown San Francisco in the event oflow frequency fluctuations)

The three barriers to contain the consequence of an electrical fault described above are shown in **Figure 18**.

Based on data examined by the investigation team, the fault could have well been confined if the differential relay for Bus 2 Section D was cut in. The underlying cause of the failure to cut in the differential current relay was determined to be the error proneness of the switching log preparation process, rather than human errors in failing to follow the switching log that returned Bus 2 Section D to service. In other words, the underlying cause was related to inadequate switching log preparation, not a procedure error. **Figure 19** shows the human errors involved in the preparation of the switching log and the three barriers to prevent the log preparation error from becoming an operator error. The OFIs that can be corrected to contain consequences of a fault are:

- Error prone switching log preparation process (OFI-6)
- Error prone work culture that is not self critical or forthcoming with problems (OFI-7)
- Inadequate protection system for local clearing (OFI-8)
- The protection system for distant clearing is not designed for fast clearing of bus faults (OFI-9)
- Current San Francisco Operating Criteria (SFOC) not designed to preserve critical load against disturbance of large voltage fluctuations or loss of generation after islanding (OFI-10)

CONSEQUENCE CONTAINMENT OF ELECTRICAL FAULTS

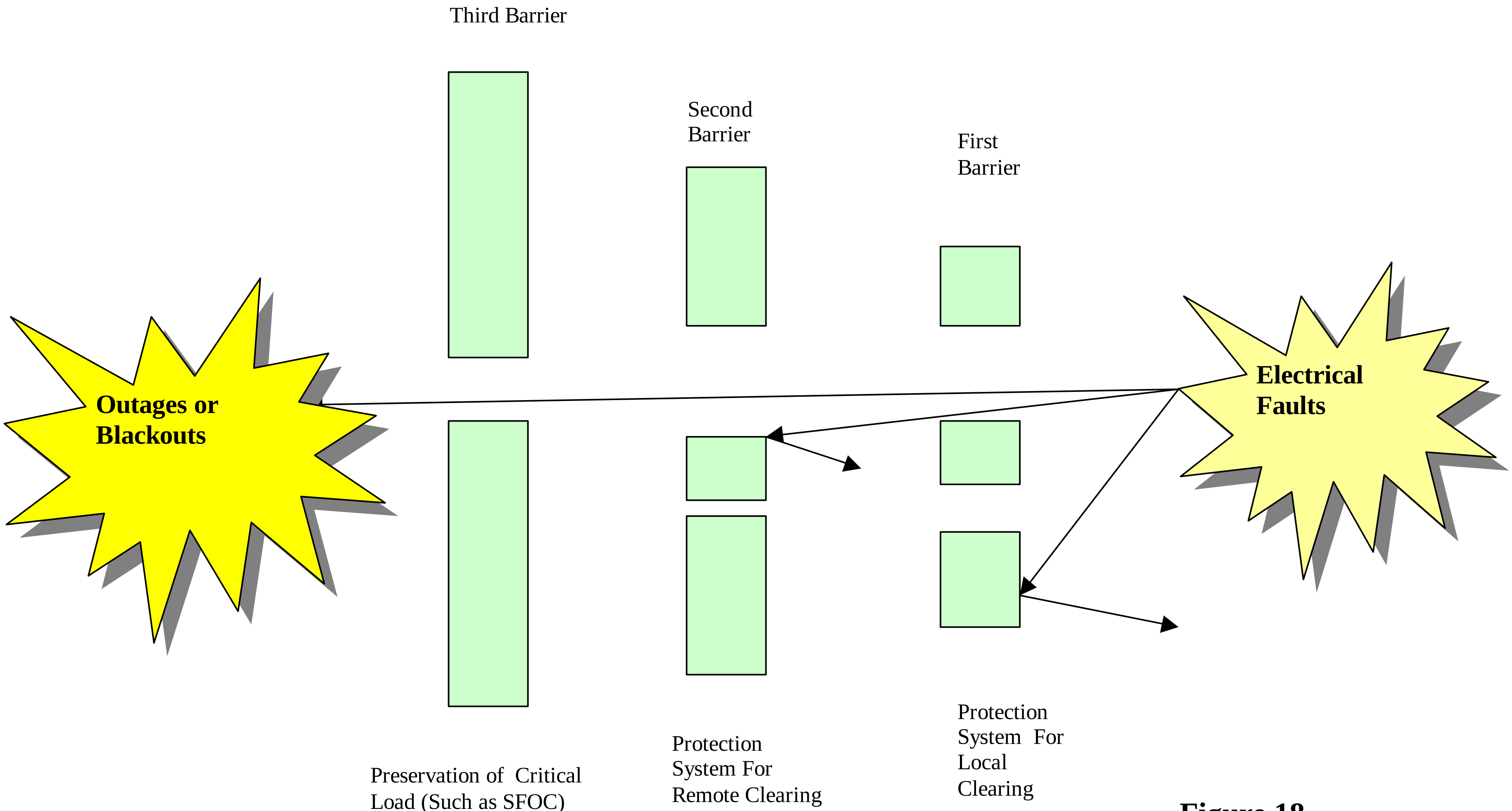


Figure 18

HUMAN ERRORS INVOLVED IN DEFEATING PROTECTION SYSTEM FOR LOCAL CLEARING

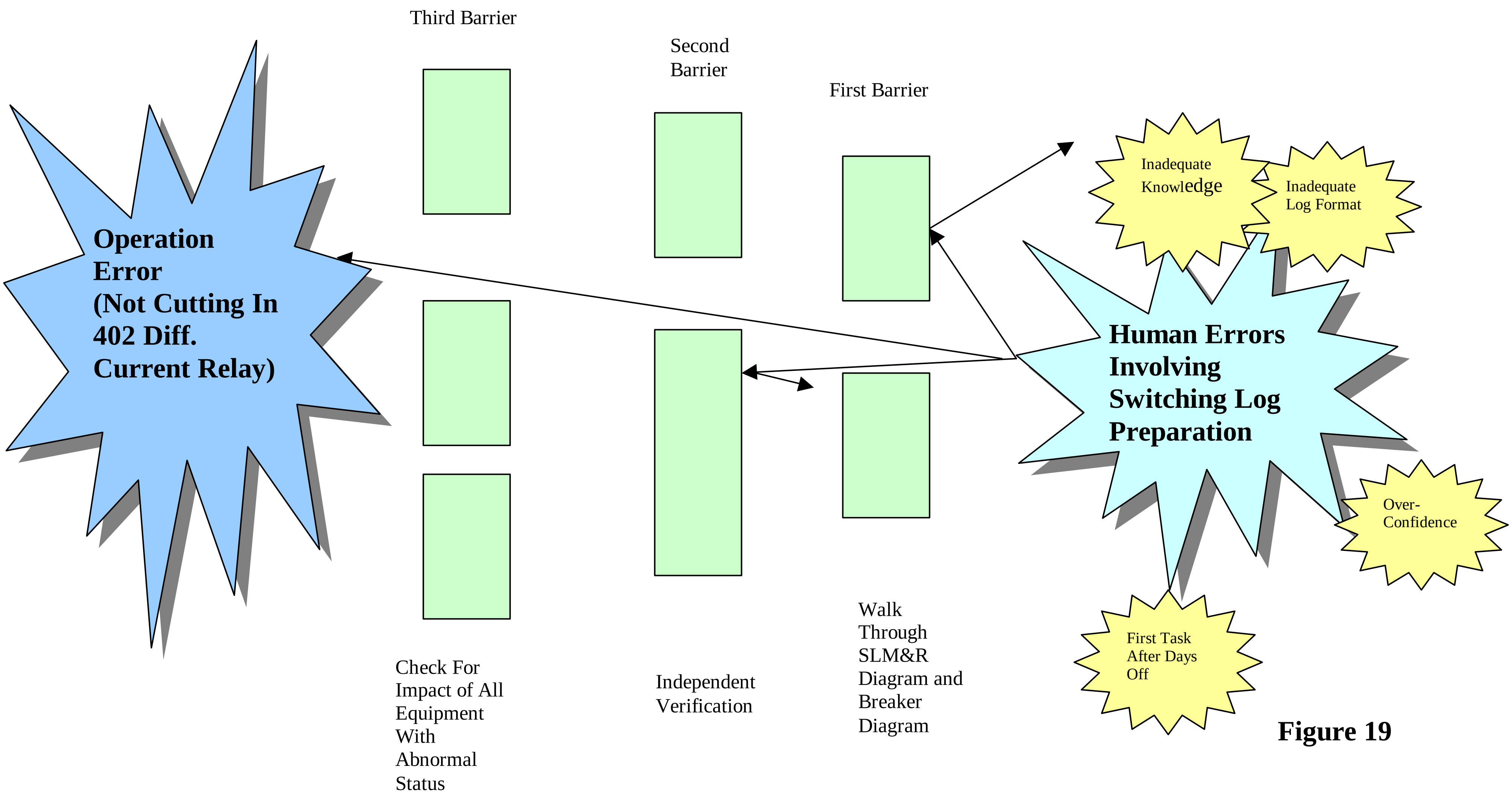


Figure 19

OFI – 6 - ERROR PRONE SWITCHING LOG PREPARATION PROCESS

Current switching log preparation practice at PG&E allows the preparers to use the "stored reference document", i.e., previously used switching logs, as references to prepare new logs.

Using reference material to prepare new switching logs can help workers save preparation time. However, the referenced switching logs may become human error traps if the operators do not know the following:

- The differences between the assumptions made in preparing the previous log versus the assumptions made in preparing the current log,
- the differences in the protection requirements, and
- the differences in configurations (breakers, relay settings, disconnects, buses, etc.) between the previous switching and current switching.

The investigation team found that there was no specific training or guidance given to the operators that would require them to examine the above mentioned differences when a referenced material is used to prepare a new switching log. Without a specific requirement to examine the differences, it is possible that an operator may fall into the over-confidence error trap, feeling that the referenced material has been used several times before and is sufficient for the current switching log.

RECOMMENDATION ON OFI-6

It is recommended that PG&E provide special training and guidance for operators to check differences when previously used switching logs are modified to prepare new switching logs. (Recommendation OFI-6.1)

OFI-7 - ERROR PRONE WORK CULTURE THAT IS NOT SELF IMPROVING OR FORTH COMING

As discussed in the DATA VALIDATION section, it is apparent that the switching log SAM98-840 was falsified. Even though the motive to do such a thing was unknown, the investigation team believes that it was done to cover the switching log preparation error. This falsification was committed and not reported to the PG&E investigation team after the event, and required more than just one individual. As such, this case reveals a severe cultural problem. That is, the work culture was not self improving (or self critical) and forthcoming in facing the actual problems.

RECOMMENDATION ON OFI-7

It is recommended that a work culture survey be performed that, among other things, determines the self improvement attitude of the work force. This type of survey will provide PG&E with data on the spread and the severity of the problem. (Recommendation OFI-7.1)

It is recommended that PG&E take actions, based on the results of the survey, to increase the self improvement attitude of the work force. The survey should be used to trend the effectiveness of the actions. (Recommendation OFI-7.2)

OFI-8 - INADEQUATE PROTECTION SYSTEM FOR LOCAL CLEARING

It is standard practice at PG&E when a bus section is taken out of service, to cut out the differential relay protection scheme for that bus section. The reason for cutting out the differential relay is to prevent spurious trips when line breakers are actuated.

The differential relay protection scheme was cut out as part of the clearance for the work on Bus 2 Section D. In its report, PG&E concludes that the differential relay protection scheme was not cut in prior to closing CB 402. It bases this conclusion on three facts. These facts are:

(1) CB 402 failed to reopen upon being closed into a fault.
(2) The differential relay operated correctly when later tested.
(3) The operator who performed the switching operations noticed that the bus differential relay switch was in the cut-out position three to four hours after the fault occurred.

Cutting out the differential relay protection scheme when taking equipment out of service is not standard practice at all utilities. For example, one of the major California utility companies does not cut out the differential relay when performing bus work. It believes that spurious trips are not as much of a problem if cutting in the differential relay has been forgotten.

As can be seen in **Figure 18**, the first barrier to prevent an electrical fault from propagating is local clearing. Local clearing for an electrical fault resulting from bus grounds is achieved by the differential relay. To ensure the existence of local clearing capability, two schemes can be used:

- Use of a back-up relay (such as an over-current relay for opening of the sectioning breakers between Bus E and D)
- Use of an interlock that prevents closing of the 402 breaker unless the differential relay is cut in

The second scheme is simpler and more reliable because its functionality does not require human actions.

RECOMMENDATION ON OFI-8

It is recommended that PG&E implement an interlock system that ensures that the differential relay is cut in before closing the bus breaker to energize the bus. A suggested interlock scheme is shown in **Figure 20**. This interlock system should also be implemented at other critical substations in which bus faults may result in San Francisco outages. (Recommendation OFI-8.1)

It is recommended that PG&E implement an over-current protection scheme for the sectioning breakers between two sections of buses. (Recommendation OFI-8.2)

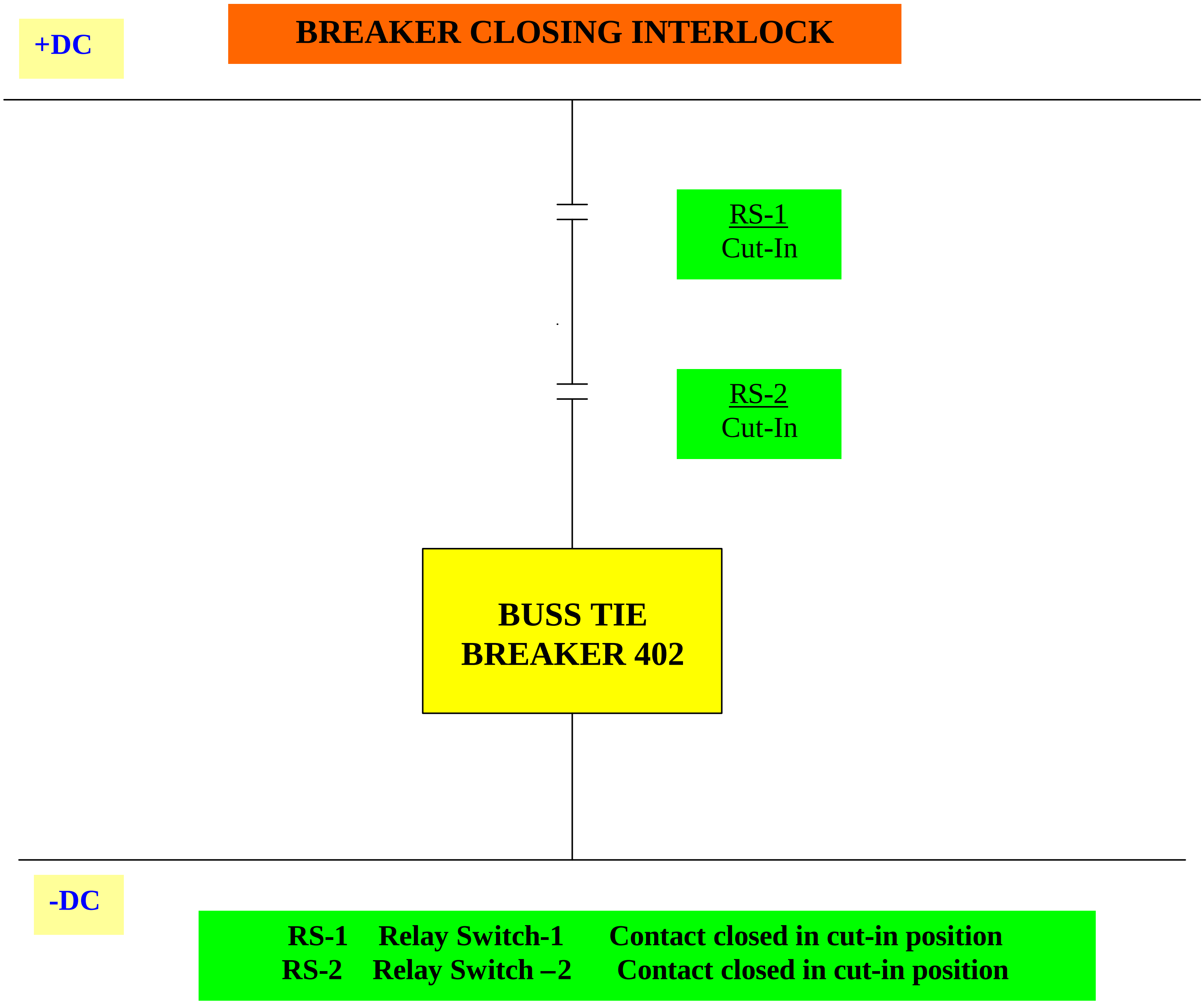

BREAKER CLOSING INTERLOCK
+DC
RS-1
Cut-In
RS-2
Cut-In
BUSS TIE
BREAKER 402
-DC
RS-1 Relay Switch-1 Contact closed in cut-in position
RS-2 Relay Switch –2 Contact closed in cut-in position

Figure 20

OFI-9 - THE PROTECTION SYSTEM FOR DISTANT CLEARING IS NOT DESIGNED FOR FAST CLEARING OF BUS FAULTS

When the primary protection is not functioning, the Zone 2 protective relays will actuate. The Zone 2 protective relays that protect ground faults that occur at San Mateo are located at Martin substation.

After the event, PG&E analyzed the instability of that system. It concluded that if the Zone 2 relays trip within 15 cycles (covering both winter and summer load conditions) after a ground fault occurs at San Mateo, the system would remain stable. As such, the San Francisco outage would have been avoided.

To effect the fast Zone 2 trip (15 cycle trip), the current directional relays currently installed at the Martin substation should be changed into digital time triggered relays.

RECOMMENDATION ON OFI-9

It is recommended that PG&E replace the Zone 2 directional overcurrent relays with digital time triggered relays with a response time of 15 cycles for three-phase faults. **Figure 21** shows a recommended design for Zone 2 fast acting relay. (Recommendation OFI-9.1)

PROGRAMMABLE LOGIC SETTINGS FOR DIGITAL DISTANCE RELAYS

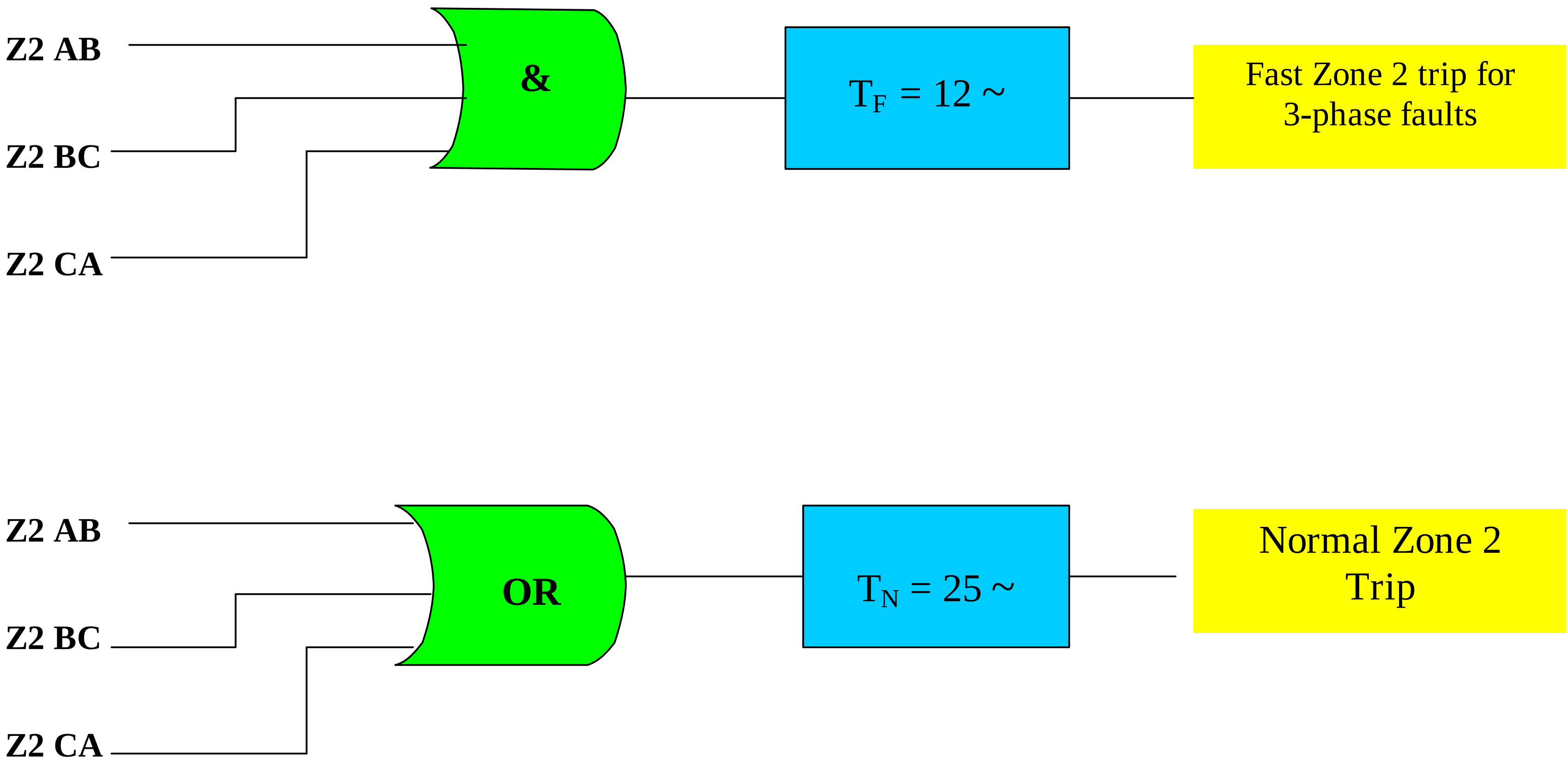


Figure 21

OFI-10 – CURRENT SAN FRANCISCO OPERATING CRITERIA (SFOC) IS NOT DESIGNED TO PRESERVE CRITICAL LOAD AGAINST DISTURBANCE OF LARGE VOLTAGE FLUCTUATIONS OR LOSS OF GENERATION AFTER ISLANDING.

BACKGROUND

The third barrier to prevent a fault from becoming an outage is the preservation of San Francisco's critical load. This barrier was achieved through the San Francisco Operating Criteria (SFOC) and the San Francisco Separation Scheme (SFSS), which is a part of the SFOC.

One of the emphases of the SFOC is to dispatch sufficient generation in the San Francisco metropolitan area so that on-line generation serves islanded load in the event of a major system disturbance or catastrophic loss of transmission at San Mateo substation. The current version of the SFOC addresses the loss of all five 115 kV transmission lines. The SFOC ensures that, if San Francisco generation does not trip during the loss of the five lines, San Francisco can be successfully islanded.

The San Francisco Separation Scheme is an under-frequency load shedding scheme, designed to protect San Francisco's critical loads (10 network group loads) against system disturbances. The SFSS separates San Francisco as an island when the frequency of disturbance drops below 58.3 Hz and the internal power generation (from Potrero and/or Hunters Point power plants) is sufficient to provide the critical load within the island, i.e., San Francisco metropolitan area. The SFSS monitors the direction of power at the Martin substation to determine if the internal power generation is sufficient to cover the critical load. If the direction of power is outgoing from Martin to San Mateo, the internal generation is sufficient to cover the critical loads.

As the frequency drops below 60Hz, but remains above 58.3 Hz during the disturbance, SFSS trips off various non-critical loads at several discreet frequencies. When the frequency drops to below 58.3 Hz and the power is flowing outward from the San Francisco area, the SFSS trips (1) all five 115 kV lines at the Martin end of the San Mateo-Martin 115 kV lines and (2) the Martin end of the San Mateo-Martin 230 kV underground line. The trips actuated by the SFSS make San Francisco act as an island, within which the internal generation is sufficient to supply its critical loads.

Since the inception of the SFOC in 1978, the SFOC (together with SFSS) has operated successfully as designed and islanded San Francisco network loads with San Francisco generation on December 22, 1982 and on August 10, 1996, when there were major system disturbances.

PG&E reported in its root cause analysis report that the San Francisco Separation Scheme was not designed to protect against the San Francisco disturbance that occurred on December 8, 1998. PG&E reported in its root cause analysis report as follows:

"The December 8, 1998, three phase fault at San Mateo substation with primary protection disabled causing system instability sufficient to lead to transmission system and power plant shutdown is outside of the Operating Criteria scope."

"The San Francisco Separation Scheme did not protect San Francisco loads from interruption during the Loma Prieta earthquake in October 1989 and December 8, 1998, outage because there was a substantial or total loss of generation along with a substantial loss of the transmission system".

The investigation team found that the key reason that the existing SFOC failed to preserve the critical load was that the voltage fluctuations of the electrical disturbance were very large so that they tripped off the generation (on low voltage trip) before the frequency ever dropped to below 58.3 Hz. Once generation was tripped off, SFSS won't operate per design because power was flowing into, not out of, San Francisco.

During the 1989 earthquake, the investigation team found that the SFSS operated successfully for a very short period of time, islanding San Francisco with a balance of generation and critical load. Soon after islanding, earthquake waves tripped off one of the plants and produced a generation-deficient situation. This situation caused the frequency to drop further and tripped off another power plant. Finally, the whole generation tripped off within San Francisco.

LIMITATION OF CURRENT SFOC AND SFSS

Comparing the SFSS responses in the two events in which they operated successfully and two events in which they failed, per design, to preserve the critical load, the investigation team found that the SFSS has two major design limits (illustrated in **Figure 22**).

(1) SFSS is not designed to protect against disturbances with large voltage fluctuations.
(2) After islanding and a balance is reached between generation and network loads, any trip in a generation plant may produce enough frequency drop to trip off all other generation plants.

ADVANCED SAN FRANCISCO OPERATING CRITERTIA

To improve the existing SFOC, the investigation team adopted the defense-in-depth concept to conceptualize an advanced SFOC. The defense-in-depth concept, which has been used to improve safety and reliability of nuclear power plants, space shuttles, and aircraft, calls for incorporating a last ditch defense regardless of what type of disturbance (or failure scenario) is encountered. For example, the current SFOC (SFSS) is designed to guard against certain types of events, such as loss of all five 115 kV lines, loss of the underground 230 kV line, etc. As such, when an event that is not analyzed or is

DEFENSE-IN-DEPTH CONCEPT FOR ADVANCED SAN FRANCISCO OPERATING CRITERIA

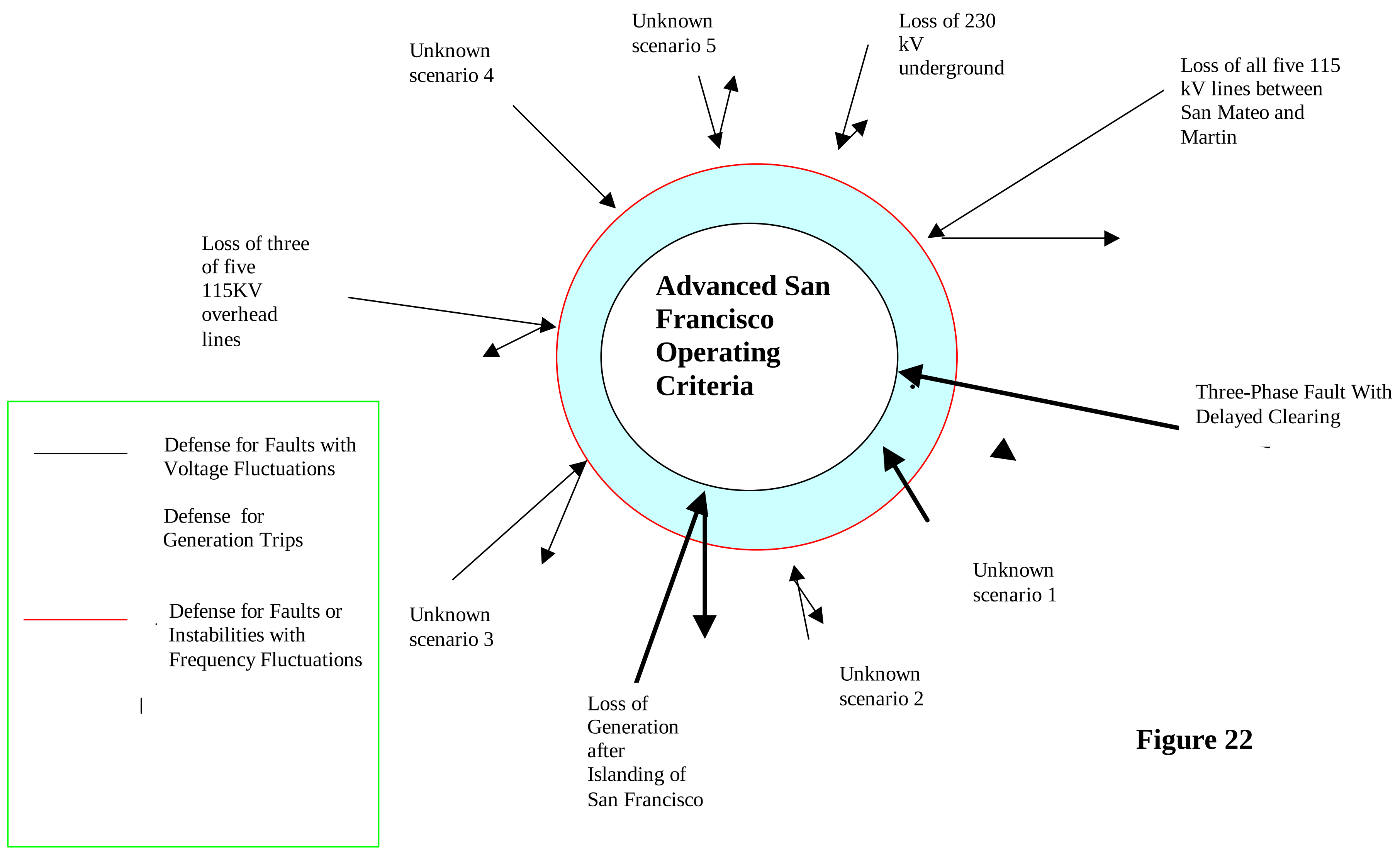


Figure 22

protected against occurs, the SFOC may fail. Because it is impossible to analyze all types of events, the defense-in-depth concept calls for a last ditch defense that covers all the events. For example, at a nuclear power facility, the last ditch of defense is sufficient cooling of the nuclear core. Regardless of failure scenarios, each of which is responded to differently by operators, the nuclear power plant is equipped with a reliable emergency cooling system that always delivers sufficient water during events.

The last ditch of the SFOC is a defense that responds to both types of disturbance, i.e., disturbances with large voltage fluctuations and disturbances with large frequency fluctuations. Also, this defense ensures that the generation and load is always in balance. **Figure 23** illustrates the concept of an advanced San Francisco Operating System.

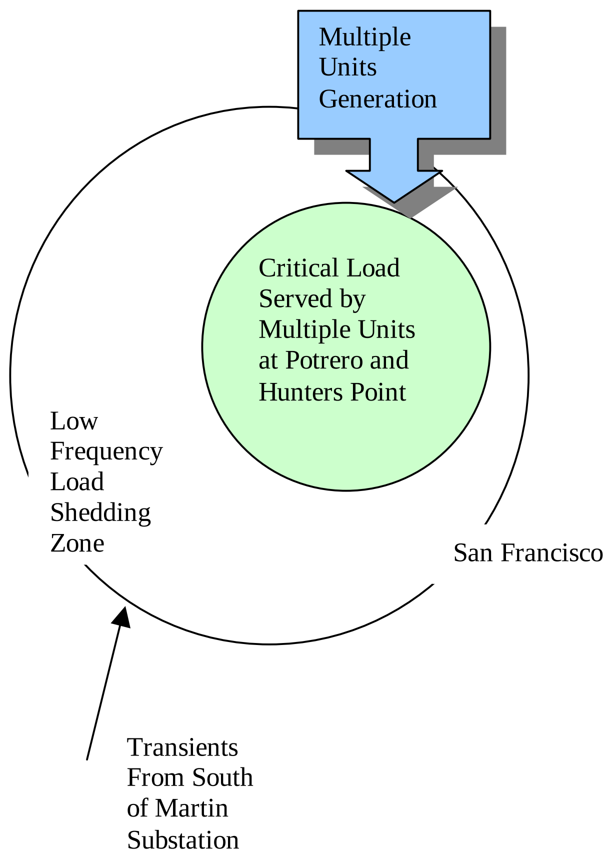
RECOMMENDATION ON OFI-10

It is recommended that PG&E design an advanced SFOC (and SFSS) that has the following two capabilities:

(1) Load shed non-critical loads and island San Francisco not only on low frequency, but also on low voltage (Recommendation OFI-10.1).
(2) After islanding, load shed equivalent load when a generation plant trips off (Recommendation OFI-10.2).

SFOC CAN BE IMPROVED TO REMOVE SOME OF ITS LIMITATIONS…

CURRENT SYSTEM



Limitations of Current SFOC

- **Low voltage transients may trip the generation and defeat the system.**
- **Loss of generation from other causes (such as earthquake, setpoint mis-setting, or equipment malfunctions) in conjunction with of low frequency transients may defeat the system.**

Advanced SFOC Concept To Remove Current Limitations

- **Load shedding on low voltage and/or low frequency.**
- **Tripping a generation unit trips an equivalent portion of the network load.**

Figure 23

RECOVERY PHASE

This phase covers the time period from when San Francisco dropped its electrical load to the time when that load was fully recovered. The total outage time was seven hours and thirty nine minutes.

Figure 24 illustrates the three barriers that can help prevent an outage from becoming a prolonged outage. These three barriers are:

- Rapid problem identification and resolution
- Rapid restoration of affected areas
- Staggered strategy (between transmission and distribution systems)

Based on the data examined, the investigation team found that the recovery time could have been reduced to about three hours from the initial fault to restoration of the last section of customers in the distribution system, had the following OFIs been avoided or corrected:

- Inadequate command and control during recovery (OFI-11)
- Inadequate human performance in communication (OFI-12)
- Not identifying and confirming the grounding problem in a timely manner (OFI-13)
- Not restoring the affected, but undamaged, lines in a timely manner (OFI-14)
- Not recovering the distribution load using a staggered recovery strategy upon recovering the transmission load (OFI-15)
- Inadequate Maintenance of Breakers (OFI-16)

Had the above OFIs been avoided or corrected, the total recovery time would have been reduced to about 3 hours. **Figure 25** shows the comparison of four major categories of recovery activities (in terms of problem identification and resolution, generation re-start, energizing transmission, and recovery of the distribution load) actual and the “should-be” situations during recovery. **Figure 26** shows a comparison of the number of the consumers versus outage time between the actual and “should-be” recoveries.

In order to institute the staggered recovery strategy, PG&E must integrate its Distribution Switching Center and its Transmission Operation Center. At the present time, PG&E’s load recovery strategy and operator training emphasis is to recover the majority of its transmission lines (i.e., energizing the lines with voltage) after a system blackout before picking up the distribution load. To speed up the load recovery for metropolitan consumers, it is a common practice to restore transmission lines and distribution loads in a staggered fashion. That is, part of the distribution load is picked up immediately after a portion of the transmission system is energized. Then, more of the distribution load is picked up after another portion of the transmission system is energized. The staggered

RAPID RECOVERY FROM OUTAGES

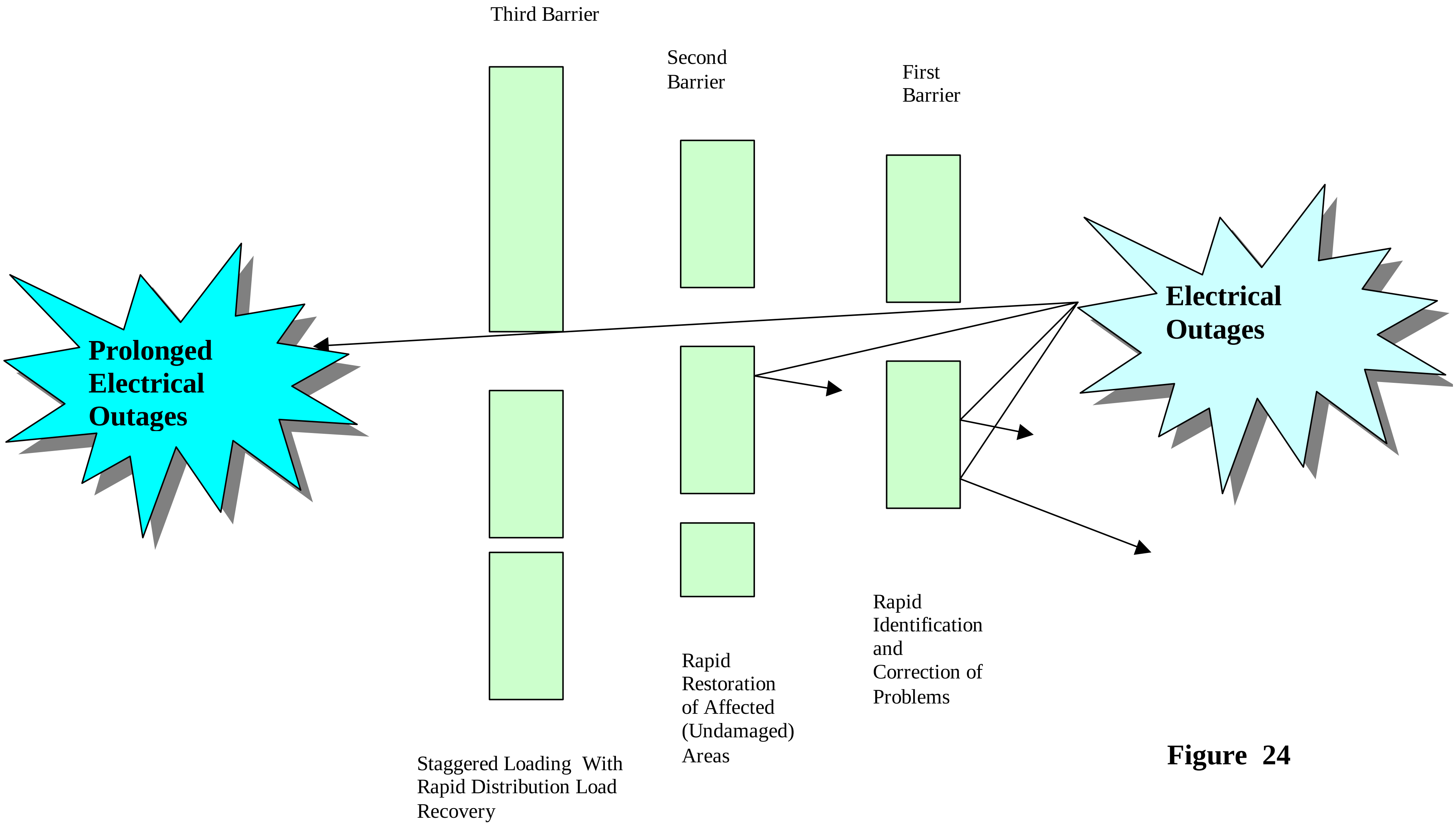


Figure 24

THE RECOVERY TIME SHOULD BE REDUCED TO LESS THAN THREE HOURS…

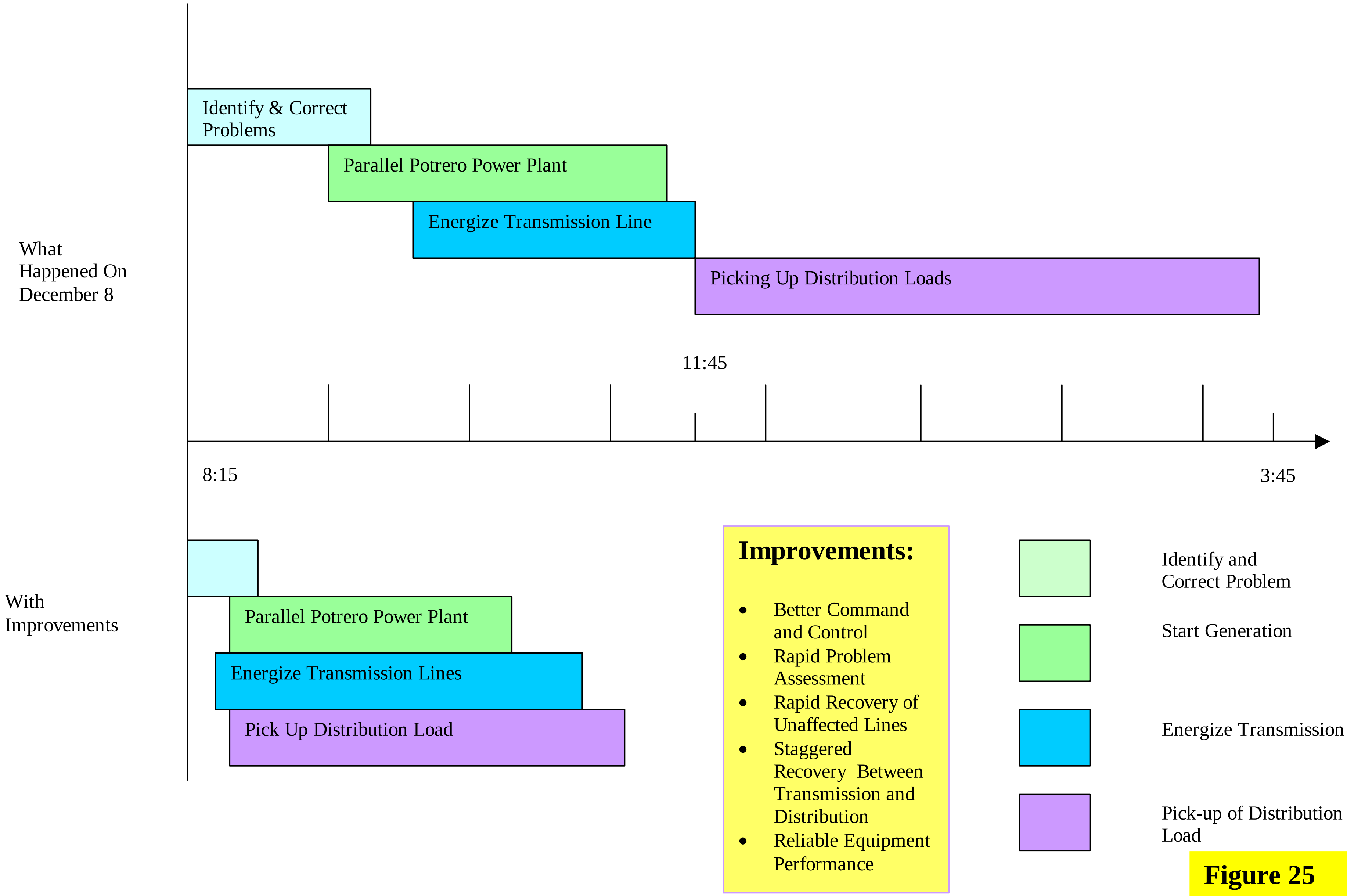
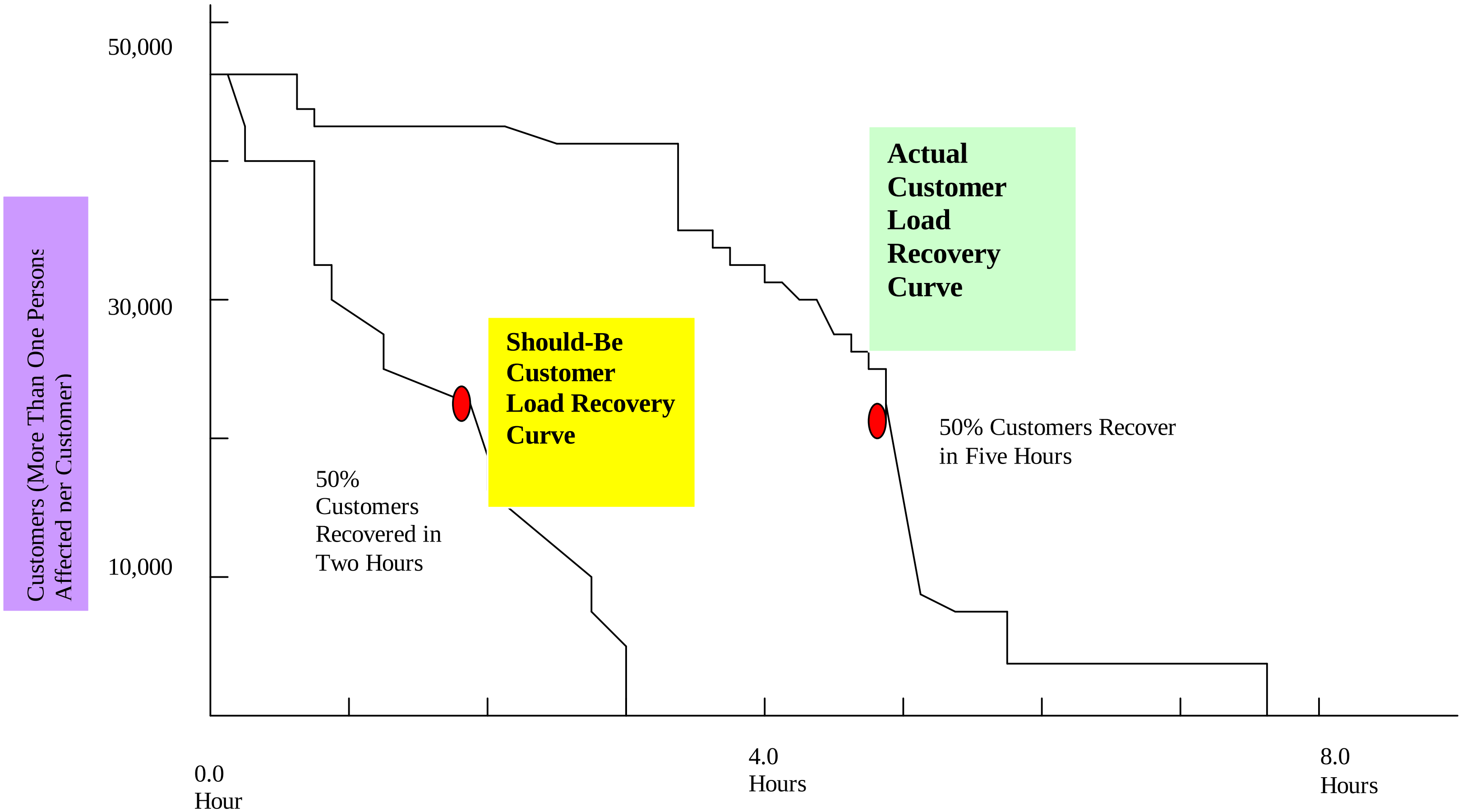


Figure 25

ACTUAL VERSUS SHOULD-BE RECOVERY TIME



[11]Performance Improvement International

Figure 26

recovery load recovery strategy usually provides a much faster recovery time during a major outage.

OFI- 11 INADEQUATE COMMAND AND CONTROL DURING RECOVERY

The investigation team believes that the command and control of the outage recovery activities was inadequate. Based on the communications recorded, it seems that neither the TOC nor the San Mateo Switching Center (SMSC) was in charge of the recovery. The inadequacy was partly due to the fact that the outage structure between the TOC and the SMSC is not clearly defined. The following are some quotes from several procedures that have different ideas about the command and control of recovery activities.

- The System Restoration-Appendix 3.2, page A3.2.2, states, "The TOC took the lead in assessing the nature of the emergency, developing a restoration strategy with the concurrence of CAISO, and implementing restoration measures."

- The Outage Investigation Report states that "It is the responsibility of operating personnel to make the initial assessment of the system and begin the restoration effort by applying their knowledge, training, and operating experience consistent with established restoration plans and priorities, General Operating Instructions, and safety rules".

- The General Operating Instructions, page 1, Switching Centers, Paragraph a, states "Switching centers shall direct and supervise the operation of those portions of the electric system delegated to them as their jurisdiction."

During the outage, the San Mateo Switching Center operators first took the lead in the restoration process. Without specific communication to the TOC, the operators planned to clear faulted Bus 2, Section D and restore Bus #1.

From 08:20, when the San Mateo Switching Center operators found they could not reset the differential relay to allow CB612 to close, until 09:05, when they did reset the relay and close 612, they did nothing else to start the restoration process.

At 09:00 it appears that the TOC senior operator did take control by instructing the San Mateo Switching Center to energize Martin Bank 7, parallel Martin 115 kV bus with energized lines from San Mateo, and energize the 115 kV lines to each power plant. The TOC's recommendation was disregarded and San Mateo Switching Center operators continued on with what they were doing with bus #1, and the four 115 kV lines off the bus. Thirty nine minutes later, after the recommendations from the TOC, at 09:39, the San Mateo Switching Center operators started energizing Bank 7 at Martin.

RECOMMENDATION ON OFI-11

It is recommended that PG&E clearly define the responsibility, accountability and authority for outage recovery activities for switching center and TOC jurisdiction. At any given time for a given type of outage, there should be no confusion about who is in charge and who is taking the role of coordinating data to identify and assess the causes and the scope of the problem. (Recommendation OFI-11.1)

OFI- 12 INADEQUATE COMMUNICATION AMONG TOC AND SMSC

Poor communications played a major role in the length of the outage. The following are a few examples of poor communication between the TOC and SMSC.

- As discussed in the "Problem Identification" portion of this report, the first two calls from the SMSC operator at 08:18, and again at 08:21, to the TOC disclosed nothing about what happened in the San Mateo switchyard at 08:15. The desk operator at SMSC heard loud explosions in the yard and was told by his operators what had happened immediately after the event, but did not disclose these facts to the TOC senior operator in the two phone calls three minutes and six minutes after the event.

- At 08:32 the SMSC operator clearly stated to the TOC operator what had occurred (grounding problem), but did not identify what station he was talking about. The SMSC operator was talking about San Mateo and the TOC thought they were talking about Martin.

- At 08:40 the TOC notified CAISO that the problem was at Martin. At this time he was confused due to the poor communication that occurred at 08:32. The TOC did not clearly understand, until forty five minutes after the event at 9:00, when or where the problem was. This miscommunication translates to a delay of about forty five minutes in recovery.

- Throughout the recovery, both the TOC and the SMSC operators did not follow the repeat-back communication requirement. This requirement requires that after receipt of a message, the receiver repeats the message back to the sender. The sender acknowledges the correct and accurate receipt of the message. This requirement is common for critical operations (cockpit operation- piloting, nuclear power plant operation, etc.). This requirement was documented in the PG&E General Operating Instructions, page 5, paragraph J, procedure for unwritten message acknowledgement.

- At 09:00, the TOC speaker 2 told the SMSC operator exactly what to do, i.e., energizing Bk 7 at Martin and paralleling the hot lines from Bus E at San Mateo to Martin 115 kV bus and energizing the 115 kV lines to the power plants. This instruction was not followed by SMSC until 09:38.

- The TOC stopped using EMS (Energy Management System) during recovery partly because of one communication error. The TOC operator thought the problematic San Mateo breaker 612 (reported as failure to close by the San Mateo operator) was the Martin breaker 612. He then noticed on the EMS that the Martin 612 breaker had a closed status. This inconsistency caused the TOC operator to question the functionality of the EMS. The abandonment of EMS resulted in some delay in recovery.

RECOMENDATION ON OFI-12

It is recommended that PG&E re-train all operators and enforce the requirement of repeat-back communication. (Recommendation OFI-12.1)

It is recommended that PG&E require all substation operators to identify their substation when they communicate to the TOC. (Recommendation OFI-12.2)

It is recommended that the TOC prepare a communication check list, in which the party (including CAISO) communicating and the information that needs to be communicated are clearly listed. The check list should be followed during the recovery phase of an outage. (Recommendation OFI-12.3)

OFI-13 NOT IDENTIFYING AND CONFIRMING THE GROUNDING PROBLEM IN A TIMELY MANNER

PG&E requires that switching centers report transmission problems to the TOC within six minutes, and the TOC communicate to CAISO within four minutes. (PG&E response to CPUC OII, 1.98-12-013.) PG&E did not meet this requirement. The following is the summary of the activities that shows that it took about 45 minutes before a clear identification of the transmission problem that occurred at 8:15 on December 8, 1998 was made.

At 08:15 the San Mateo Switching Center (SMSC) switchman closed CB402, energizing a grounded Bus #2, Section D. Because the primary protection relay was not cut in, the delayed clearing (Zone 2 relays) of the fault from the far end of the grounded lines actuated. Before the delay clearing opened the Martin breakers (35 cycles after actuation), Section D Bus #1 cleared the fault due to a ground tail burning open on section # 2, swinging o ver to Bus #1 and causing a bus differential fault on Bus #1.

Based on the interview notes, the three operators on duty at SMSC immediately heard loud explosions in the 115 kV switchyard. The operator at the desk (in charge) became busy answering telephones and assessing the situation. He did not check SCADA alarms because he was alone and very busy and was trying to stop the alarms.

The other two operators, the switchman immediately ran outside to check for personnel safety (construction crew in yard) and equipment damage. They saw a loose ground cable smoking and observed the other grounds attached to Bus #2, Section D. The switchman ran out to CB 402 to check for damage and the other operator ran back into the control room and reported the conditions to the operator at the desk.

The SMSC operator called the TOC at 08:18 and notified him that they had alarms and were investigating. The operator used non-specific communications to the TOC and did not correct the TOC senior when the senior said, “It looks like Martin 712”.

The SMSC called the TOC senior at 08:21 and again gave non-specific information to the TOC. After the communication, the TOC senior decided not to trust his EMS data partly because of miscommunications regarding breaker 612, which was shown on EMS to be closed when it was reported open.

The SMSC operator clearly stated to the TOC at 08:32 what had occurred, but did not identify the station about which he was speaking. The SMSC was talking about San Mateo and the TOC was thought they were talking about Martin.

At 08:40, the TOC notified CAISO that the problem was at Martin. The TOC did not understand, until 09:00, where or what the problem was because of several communication errors (or failures) between SMSC and TOC operators. These miscommunications caused a forty minute delay in recovery.

ANALYSIS

After the initiation of the event, the desk operator was busy at the phones assessing the situation and trying to stop the alarms. For some time after the fault, SCADA alarm point changes were averaging 100 changes per second. They averaged 100 points per minute for the next two hours, which equaled 10,500 changes.

To avoid information overload, the SCADA alarms should be made more user friendly. For example, SCADA could be programmed so that in a large outage only the most important alarms come in first, such as Bk 7 at Martin and the 115 kV lines at Martin. Only when demanded would SCADA display other, less important, alarms.

The investigation team believes that a complete and proper identification and assessment of the fault at San Mateo should have taken no longer than 15 minutes. There were three operators, a construction crew, and two construction foremen at the station at the time of the fault. With a fifteen minute assessment time, the restoration could have started thirty minutes earlier at 08:30.

RECOMMENDATION ON OFI-13

It is recommended that PG&E develop a problem identification protocol, which clearly defines the actions needed to assess the problem in a systematic manner and the problem reporting requirements for timely reporting to TOC. This protocol should be taught to both substation and TOC operators. (Recommendation OFI-13.1)

It is recommended that PG&E modify the SCADA alarm system so that only the critical alarms come in after an outage. If needed, the operator should be able to obtain less important alarms. (Recommendation OFI-13.2)

OFI-14 NOT RESTORING THE AFFECTED, BUT UNDAMAGED LINES, IN A TIMELY MANNER

Based on the TOC senior log and interview notes, after the event, the first thing SMSC operators planned to complete was the isolation and clearing of the grounded Bus #2 so that grounds could be removed. They then planned to energize Bus #1 and close the four line circuit breakers they knew were open at SMSC. They thought the only area affected was locally at San Mateo substation. This plan and the conditions at SMSC were not reported to the TOC.

The SMSC operators were initially unaware that the problem extended north of San Mateo into San Francisco (per PG&E Investigation report.) According to the SMSC chronological log, at 08:19 the operators knew a large area of San Francisco was out of power, including Airport, Mission, Martin, HPPP, PPP, Bay Meadows and Bayshore.

From 08:19 until 09:05, the two extra operators spent 45 minutes trying to reset the bus differential relay for Bus #1 so they could restore power to Bus #1. At 09:05 the differential relay was reset.

At 11:34 at San Mateo Sub, inspection of Bus #2, Section D was completed and all grounds were removed.

ANALYSIS

The operators planned to clear the grounded bus so that grounds could be removed. This should have been low priority work, since the bus had been out of service for four weeks. This restoration plan distracted the operator from restoring power through the unaffected Section E lines.

When the operators tried to energize Bus #1, the differential relay would not reset. Two operators each spent forty five minutes trying to reset this relay. The reason for the failure to reset was later found to be caused by the mis-wiring of relays in 1991.

The investigation team believes that the two operators should have recognized that their time would have been better spent in the control room reviewing the scope of the outage and let the maintenance department work with the differential relay problem. By doing so, they might have saved a minimum of forty five minutes of restoration time.

RECOMMENDATION ON OFI-14

It is recommended that PG&E establish a policy regarding rapid assessment of the scope of the outage and the best way to recover the affected, undamaged lines. The division of work between maintenance and operations should also be addressed in the policy. (Recommendation OFI-14.1)

OFI – 15 NOT USING A STAGGERED STRATEGY TO RECOVER CUSTOMER LOAD

The PG&E restoration process took seven hours and forty minutes, including problem identification and assessment time. The restoration process used by PG&E requires that the transmission system be back to its normal configuration before much of the distribution load is restored. PG&E has three separate phases in the restoration process. The three phases are problem identification and assessment, transmission system restoration, and distribution system restoration (per PG&E outage report). The California Independent System Operator (CAISO) also has control over when PG&E can start their distribution system restoration.

The investigation team believes that there should only be two phases of restoration - problem identification and assessment, and customer restoration. It is understood that adequate transmission is necessary for customer restoration. However, the restoration of the transmission system and distribution system should be in parallel, while still allowing enough capacity on the transmission side to maintain stability of the grid. This is referred to as a staggered recovery strategy by utilities that restore customers in this manner.

With Energy Management Systems and SCADA systems available to operators, the TOC, and CAISO personnel, keeping transmission stable while restoring customers is feasible and should be practiced. This approach to restoration is used by many large utility systems in large metropolitan areas.

ANALYSIS

If this staggered recovery strategy of restoration had been used by PG&E, the customer restoration time could have been reduced by about ninety minutes.

The investigation teams reviewed the PG&E actual outage restoration sequence and the Electric Restoration Plan. 12 steps out of the Electric Restoration Plan between Martin, San Mateo, Mission, Larkin, Hunters Point Power Plant, and Potrero Power Plant could have allowed restoration of power to 54% of their customers while the grid remained stable. The investigation team realizes that because the outage was not a total outage, the emergency plans for Martin and San Mateo could not be used as written and parts of the plans had to be pulled out and used as needed.

At Martin, page 11 of the restoration plan:

#1 Perform step 6, energizing Bk 7

#2 Perform step 7, restoring 230 kV bus normal

#3 Perform step 8, restoring 115 kV buses 1&2 and station service

#4 Perform step 10, energizing HP-1

#5 Perform step 11, energizing HW-1

At San Mateo, page 7 of restoration plan:

#6 Perform step 6, close Martin end of #6 115 kV line

#7 Perform step 7, close Martin end of #5 115 kV line

#8 Perform step 12, close Martin end of #3 115 kV line

Page 20, restoration plan:

#9 Close Martin 122 to Larkin, HY-1 115 kV line

#10 Close Martin 362 to Potrero PP HW-2 115 kV line

#11 Close Bayshore 182 to Potrero PP AW-2 115 kV line

Page 17, restoration plan:

#12 Close PPP 182 to Mission AX 115 kV line

These steps are not meant to be a complete switching log, but these basic steps would place 918 MVA of capacity at Martin 115 kV bus and some 115 kV capacity at the downtown stations, Larkin, and Mission. 918MVA at Martin should allow about 450MW of actual power to be used to pick up selected customer load, while grid stability is maintained.

The 918 MVA of power is derived from the normal loading capacity of the Martin Bank 7, San Mateo-Martin Line #3, #5, and #6. The 918 MVA is derived as follows:

Martin Bk7	403MVA	
SM-Martin #3	200	
SM-Martin #5	115	(Minus 85MVA at airport)
SM-Martin #6	200	
	918MVA capacity at Martin	

ANALYSIS

Once the operators knew they could not reset the Bus 1 differential relay system for bus Section D, a quicker restoration of the system would have been achieved by using the energized 115 kV lines from San Mateo bus Section E to Martin and paralleling to Bk7 at Martin.

At 08:20 the SMSC operators found they could not close 612 to heat up bus Section D. They spent forty five minutes there before the relay was reset and they continued on Section D.

If the operators had left the differential relay problem to the maintenance department and continued restoration according to a plan similar to the plan described above (also described in the Electric Restoration Plan), the investigation team believes that the power would have been available (and available to pick up distribution load) to Larkin, Mission and Potrero by 09:00.

At 09:00, 54% of needed power to restore the customer load could have been available. At 09:30 customer load restoration could have started using the Staggered Recovery method of restoration.

By 10:15, 50% of customer load could have been picked up and the transmission system could have been complete by 11:00. 100% of customer load could have been restored by 11:15, three hours into the outage.

RECOMMENDATION OF OFI-15

It is recommended that PG&E adopt a staggered recovery strategy to reduce recovery time. This strategy should be proceduralized, taught to, and practiced by all TOC and Switching Center operators. (Recommendation 15.1)

OFI –16 INADEQUATE MAINTENANCE OF BREAKERS

In this section, two separate sections are written to cover breaker problems for distribution and transmission breakers.

DISTRIBUTION BREAKER FAILURES

The investigation team reviewed the post-outage test and before-outage test records. Of the ten distribution circuit breaker failures, eight were mechanical failures, one was an automatic reclose failure, which during re-testing would not repeat the failure to close, and one tripped because it was incorrectly wired to the underfrequency relay scheme.

Five of these failures caused even more extensive delays to some customers:

Millbrae 1102/2	1hour 42minute delay to 2,957 customers
East Grand 1400/2	1hour 30minute delay to12,004 customers
Martin Bk G-1/2	41 minute delay to 20,988 customers
Potrero 1110/12	35minute delay to1,351 customers
Martin 1108/2	30 minute delay to1,372 customers

Of the eight mechanical failures, three of them failed due to mechanism adjustments. Two of the three failed breakers were just overhauled in February 1998 and July 1998.

Four of the eight breakers failed due to aged grease, which caused operating coils to burn up.

TRANSMISSION BREAKER FAILURES

Five transmission circuit breakers failed and one opened early. Of the five circuit breakers, only three failed mechanically, one would not close because of a differential relay re-set problem, and one was due to a faulty setting on a timer relay.

San Mateo 612	failed to reset
Martin CB42	failed to close
Mission CB462	failed to close
Protrero CB192	failed to close

Attempts to reset the San Mateo 612 breaker delayed the recovery by about forty minutes. Failure to close the Potrero CB 192 delayed 104 MW delivered from Potrero Power Plant for 2 hours. The failure was related to a faulty closing valve, and later maintenance found aged (gummed-up) grease in the relevant mechanism.

ANALYSIS

Five of the failed distribution circuit breakers that were maintained in 1998 averaged 5.4 years of overdue maintenance before maintenance was done. Based on the lapsed time of overdue and lubrication aging problem, the investigation team believes that the current maintenance scheduling and backlog are inadequate.

RECOMMENDATION ON OFI-16

It is recommended that PG&E review all the overdue maintenance in the distribution and transmission breakers. (Recommendation OFI-16.1)

It is recommended that PG&E improve its maintenance program based on the feedback of root cause analysis results from failed breakers. (OFI-16.2)

It is recommended that PG&E improve its installation testing program (for breakers and other equipment) to detect failures before operation. This program shall cover all major equipment, including SCADA back-up power supply. (OFI-16.3)

INADEQUATE MANAGEMENT CONTROL OF HUMAN PERFORMANCE

More than 140 human errors were committed throughout the December 8, 1998 outage. Because human errors were very prevalent throughout the San Francisco outage, the investigation team examined several critical factors that are needed to control and improve field human performance. These factors are illustrated in **Figure 1**. **Figure 1** is called the human performance control loop. It begins with setting up expectations of workers' human performance by the senior management. The senior management's expectations are translated into various requirements in the operating procedures (such as the Grounding Manual or switching logs) and passed down through middle managers to supervisors (in supervisory expectations). Supervisory expectations and operating procedures set up the behavior standards in the field.

As can be seen in **Figure 2**, to control human performance in the field, human performance has to be constantly monitored and deviations from senior management's expectations must be noted. The root causes of the deviations are analyzed and cost effective corrective actions are implemented in a timely manner to change human performance of the organization. If all of the elements (such as performance monitoring, root cause analysis, accountability, etc.) depicted in the human performance control loop are in existence, the organization's human performance will always be at the same level as that expected from the senior management. If some of the elements are missing, the human performance will fluctuate or be substandard when there are resource challenges (such as high turn-over rates, inadequate training, etc.) to the organization.

Figure 3 shows the benefits of a human performance control loop. With a strong human performance control loop in place, the effects of disturbances in an organization (such as staff reduction, budget cut, re-organization, losses of knowledgeable personnel) are closely monitored and, if they result in higher human error rates, are corrected in a timely manner. Without a human performance control loop, organizations may run well in absence of disturbances. However, a few years after disturbances occur (such as a few years after a major re-organization or a major budget cut), human performance will gradually degrade and the human error rate will gradually increase.

Based on the data examined by the investigation team, the senior management's expectations of the workers' human performance are relatively high. Nevertheless, the high management expectations did not propagate to performance standards in the field. The following OFIs exist to improve the human performance control loop:

- Lack of field human performance monitoring and trending (OFI-17)
- Inadequate translation of senior management's expectations into operating procedures and supervisor's expectations (OFI-18)

- Inadequate analysis capability to identify underlying human performance problems (OFI-19)
- Inadequate lessons-learned process to learn lessons from previous events (OFI-20)

PG&E has started a root cause program for its construction, distribution, and transmission personnel since 1998. This root cause program helps correct problems specific to a switching center. However, the program is incapable of detecting and correcting underlying human performance issues (such as procedure development process problems). This root cause program helps correct problems specific to a switching center. The OFIs are described in detailed below.

OFI-17 LACK OF HUMAN PERFORMANCE MONITORING AND TRENDING

Without monitoring and trending human performance in the field, PG&E management cannot know whether there are human performance issues and, if they exist, the spread and the severity of the problem. Most methods used to monitor human performance in the field are shown in **Figure 27**. As can be seen in this figure, there are four methods used by other utilities to monitor human performance in the field. These four methods are briefly described below:

- Work Culture Survey (also called a Safety Culture Survey) – Based on extensive research performed by Performance Improvement International over the past eight years, there is a strong correlation (R-Square = 61%) between work culture and the future event rate. This correlation remains valid regardless of the type of organization or type of industry. Usually, work culture can be divided into five components:

    - Understanding of management's expectations in the field
    - Level of knowledge and skills
    - Lateral integration (communication and team work)
    - Reliable and simple processes
    - Self improvement attitude

- Field Audit – Field audits usually look at the operation and maintenance records to determine if the operation and maintenance policies are observed by the field personnel. The auditors sometimes observe and assess specific activities performed in the field to determine if they comply with company policies.

- Field Human Error Observation by Co-Workers – Some organizations use co-workers to observe human error traps or inducers in the field. The observations are grouped and trended so that major human error inducers are intervened and corrected before they cause major events.

- Root Cause and Common Cause Analysis – Significant events, such as events that result in loss of significant distribution load, are analyzed for the root causes that are embedded in the work practices, procedures, and management systems. The root causes of these significant events are grouped to find the common causes that cause multiple events. Based on the severity and spread of the common causes, the organizations implement corrective actions to prevent recurrence. The investigation team believes that common cause analysis can help solve multiple problems all at once. Therefore, it can help an organization improve its performance rapidly.   .

The investigation team reviewed PG&E's program for monitoring the human performance in the field. The review findings are summarized below:

- PG&E has a root cause program in place. However, based on a review of 100 sample root cause analyses, more than 97% of the reports reported only what happened, not

METHODS TO MONITOR FIELD HUMAN PERFORMANCE

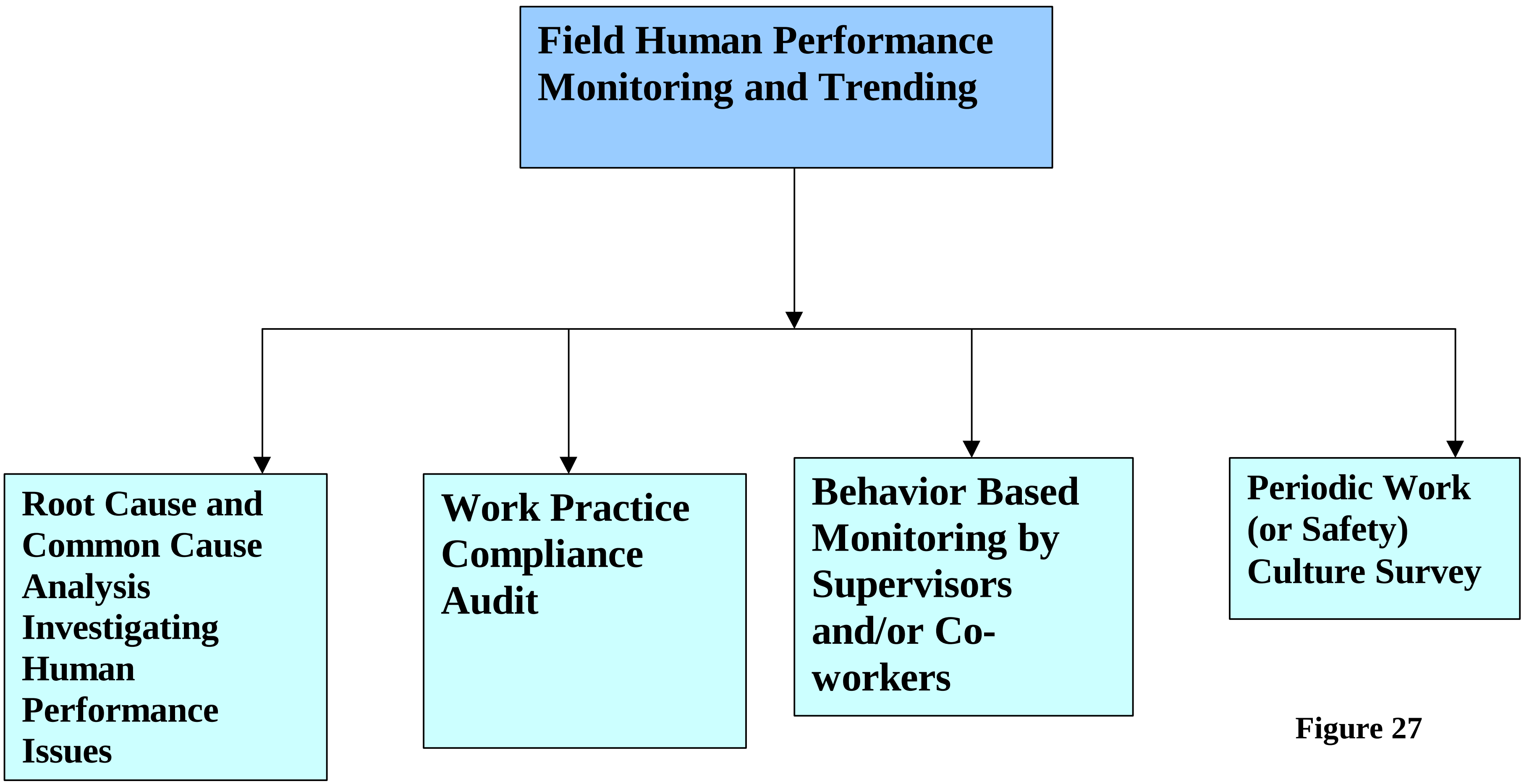


Figure 27

why the event occurred. These root cause analyses documented mainly what broke and when and how it was fixed. No or little analysis of the root causes (such as process problems, human performance problems, human error inducers, etc.) of events was included in the reports.

- PG&E does not perform periodic work culture surveys to understand the trend of the work culture.

- PG&E does not perform common cause analyses to understand the underlying causes of the events.

- PG&E has an audit program which, among other things, audits a few aspects of human performance in the field. The audited items include knowledge level of field operators of the San Francisco Operating Criteria. Based on a review of a few recent audit reports, the investigation team feels that the current field audits are very shallow and do not identify critical issues, such as high maintenance backlog, operation procedure non-compliance, etc.

- PG&E does not trend human performance problems in the field so that the senior management may not know the trend of human performance and, if needed, intervene human performance problems in a timely manner.

RECOMMENDATION ON OFI –17

It is recommended that PG&E improve the quality of its root cause investigations by instituting appropriate root cause training and by monitoring the quality (and feeding back to the writers) of individual root cause analyses. (Recommendation OFI-17.1)

It is recommended that PG&E improve its field audit program and train field auditors to observe and examine field human performance problems, such as procedural non-compliance. (Recommendation OFI-17.2)

It is recommended that PG&E perform a work culture survey (which covers critical components that directly affect future event rates) to determine the severity and depth of human performance problems in the field. (Recommendation OFI-17.3).

OFI – 18 INADEQUATE TRANSLATION OF SENIOR MANAGEMENT'S EXPECTATIONS INTO OPERATION PROCEDURES

Figure 28 shows how senior management's expectations can be translated into behavior standards in the field. As can be seen in this figure, the senior management's expectations of workers' performance are usually written down in a high-level policy procedure. At PG&E, this high level policy is its General Operating Instructions (GOI), written by two PG&E officers in 1990 for all transmission and distribution personnel. This GOI is still valid and used within PG&E.

The written senior management's expectations are incorporated either into low-level operating procedures (such as the Grounding Manual) or into middle management or supervisory training. Either through the operating procedures or through daily supervisory guidance, the workers comply with the senior management's expectations.

Figure 29 shows a comparison of four problematic aspects involved in the December 8, 1998 outage between senior management's expectations and the actual work practices in the field. As can be seen in this figure, the senior management's expectations of workers' performance in the field are high and adequate. However, these expectations are not followed by the workers in the field because they are not required by low-level operating procedure or reinforced daily by their supervisors.

The investigation team believes that had these four expectations been followed by PG&E workers, the December 8, 1998 outage could have been avoided.

RECOMMENDATION ON OFI-18

It is recommended that a PG&E senior management team perform an analysis to review the expectations of their workers and ensure that these expectations are still valid. Then, modify the GOI, low level operating procedures, and middle management and supervisor training accordingly. (Recommendation OFI-18.1)

PROPOGATION OF MANAGEMENT EXPECTATIONS

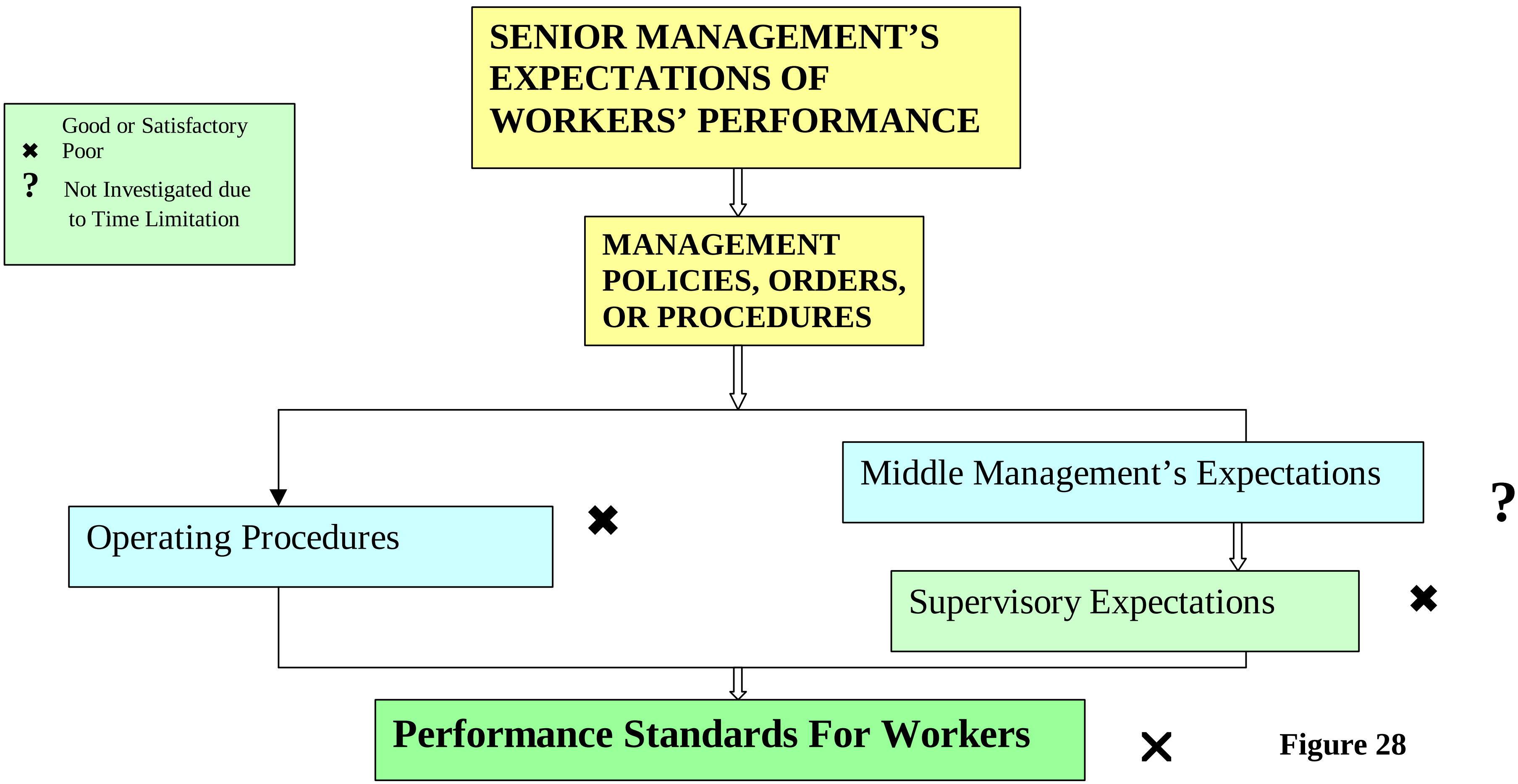


Figure 28

PROPAGATION OF SENIOR MANAGEMENT EXPECTATIONS HAS NOT ALWAYS BEEN EFFECTIVE – A FEW EXAMPLES.

Senior Management's Expectations	**Description in PG&E's General Operating Instructions (Authored by Officers of PG&E)**	**Work Practice Revealed By the December 8 Outage**
Acknowledge of Unwritten Messages or Orders	Any person receiving an unwritten message…*repeat the information to the sender, and receive an acknowledgement.*	Not a current practice (per TOC conservation transcript) - Had this expectation been carried out on December 8, confusion related to which 612 breaker and which station were problematic during outage recovery could have been avoided.
Testing Equipment After Work	In the event that it is impossible or unsafe to test at the time work is completed, testing *must be done* as soon thereafter as possible.	Not a current practice for bus work - Bus 2 Section D was not tested after work.
Caution Tags on Grounds	Station grounds … They should be *caution tagged* to the switching center.	Not a current practice for portable grounds - had the caution tags been put on the grounds and been tracked, grounds could have been positively tracked and removed.
Qualification of Personnel	Portable type grounds shall be applied and removed by *qualified personnel.*	Members of the construction crew at San Mateo who installed the grounds had not received ground removal training.

Figure 29

OFI –19 INADEQUATE CORRECTIVE ACTION PROGRAM

The purpose of a corrective action program is, on behalf of PG&E's senior management, to track and coordinate all corrective actions that are recommended from various substations or result from root cause analysis. The purpose of this type of program is to ensure timely implementation of cost effective measures to correct equipment and human performance problems.

PG&E has no such program for corrective actions derived from distribution and transmission root cause analysis.

RECOMMENDATION ON OFI-19

It is recommended that PG&E implement a corrective action program that tracks the implementation of the corrective actions. (Recommendation OFI-19.1)

It is recommended that PG&E's senior management be briefed on the status of corrective actions on a monthly basis. The senior management should be held responsible for timely implementation of committed corrective actions. (Recommendation OFI-19.2)

OFI-20 INADEQUATE LESSONS-LEARNED PROCESS TO LEARN LESSONS FROM PREVIOUS EVENTS

PG&E has started a root cause program for its construction, distribution, and transmission personnel since 1998. This root cause program will help to correct problems specific to a switching center. However, the program is incapable of detecting and correcting underlying programmatic issues or human performance issues (such as procedure development process problems). Moreover, the root cause program for construction, distribution, and transmission does not examine lessons learned from the generation division of the company. The following are a few examples that lessons were not learned from previous events.

- After the 1997 Pittsburg substation grounding event, a root cause analysis was performed. In its recommendations section, it stated that the following:

  " When it becomes necessary to perform grounding this way, different crews installing and removing the grounds, a written list of the number of grounds used will be made. This will be added where possible to the switching tag at the restore (restoration) of the tag"

- After the 1995 Diablo Canyon grounding event, a detailed root cause analysis was performed. The corrective actions implemented at Diablo Canyon Nuclear Power Plant consisted of the following:

  - Tagging and tracking the grounds used
  - Mandatory pre-job briefing (also called tailboarding) for grounding installation and removal

The investigation team found that neither of the recommended corrective actions above was implemented for the construction, distribution and transmission departments.

RECOMMENDATIONS ON OFI-20

It is recommended that PG&E strengthen its root cause program, which will track the implementation and effectiveness of the corrective actions. (Recommendation OFI-20.1)

It is recommended that PG&E exchange lessons learned between its generation unit and its construction, distribution, and transmission units related to human performance problems and major electrical components (such as breakers, transformers, etc.) failures. (Recommendation OFI-20.2)

ERROR PRONE WORK CULTURE

Work culture (also called safety culture) is an important parameter that determines future event rates. Work culture is a leading indicator for future human performance. The worse the work culture, the more the human error rate in the future. The higher the human error rate, the higher the event rate.

Based on Performance Improvement International's research, work culture is formed by the work force over time based on its perception and acceptance of the behavior standards established by the management. The higher the perceived behavior standards, the better the work culture. The behavior standards are established by senior management either through operating guidance or through supervisory reinforcement.

Regardless of organization type (engineering organization, operation organization, etc.), cultural background (i.e., Chinese culture, Spanish culture, etc.), or industry (i.e., power industry, manufacturing industry, etc.), it is found that work culture (which is quantitatively measured) is inversely proportional to event rate. Based on a linear correlation analysis, R-square is equal to 61%. This means that about 61% of the future events are affected by work culture.

How do we know there are work culture issues? **Figure 30** shows the four common symptoms of poor work culture. These symptoms are:

- Not self critical
- Not forthcoming to face problems
- Forming error prone habits over time
- Forming coalition to resist criticism or changes

Throughout the investigation, the investigation team observed all four symptoms for personnel involved in the event (i.e., TOC operators, SMSC operators, and construction crew). The following are a few examples:

- After the outage, the San Mateo operators decided to falsify a switching log. They were not forthcoming or self-critical regarding the errors they made that initiated the outage.
- The PG&E investigation did not cover problematic areas in the work culture or management system. Instead, its investigation focused on human errors made by workers.
- Even though it was required by PG&E's senior management to use the repeat-back technique to avoid communication errors, it was not used by the TOC or SMSC throughout the event. This means that a habit of not using the repeat-back

ERROR PRONE WORK CULTURE MAY RESULT IN AN INCREASING RATE OF EVENTS (OR OUTAGES)…

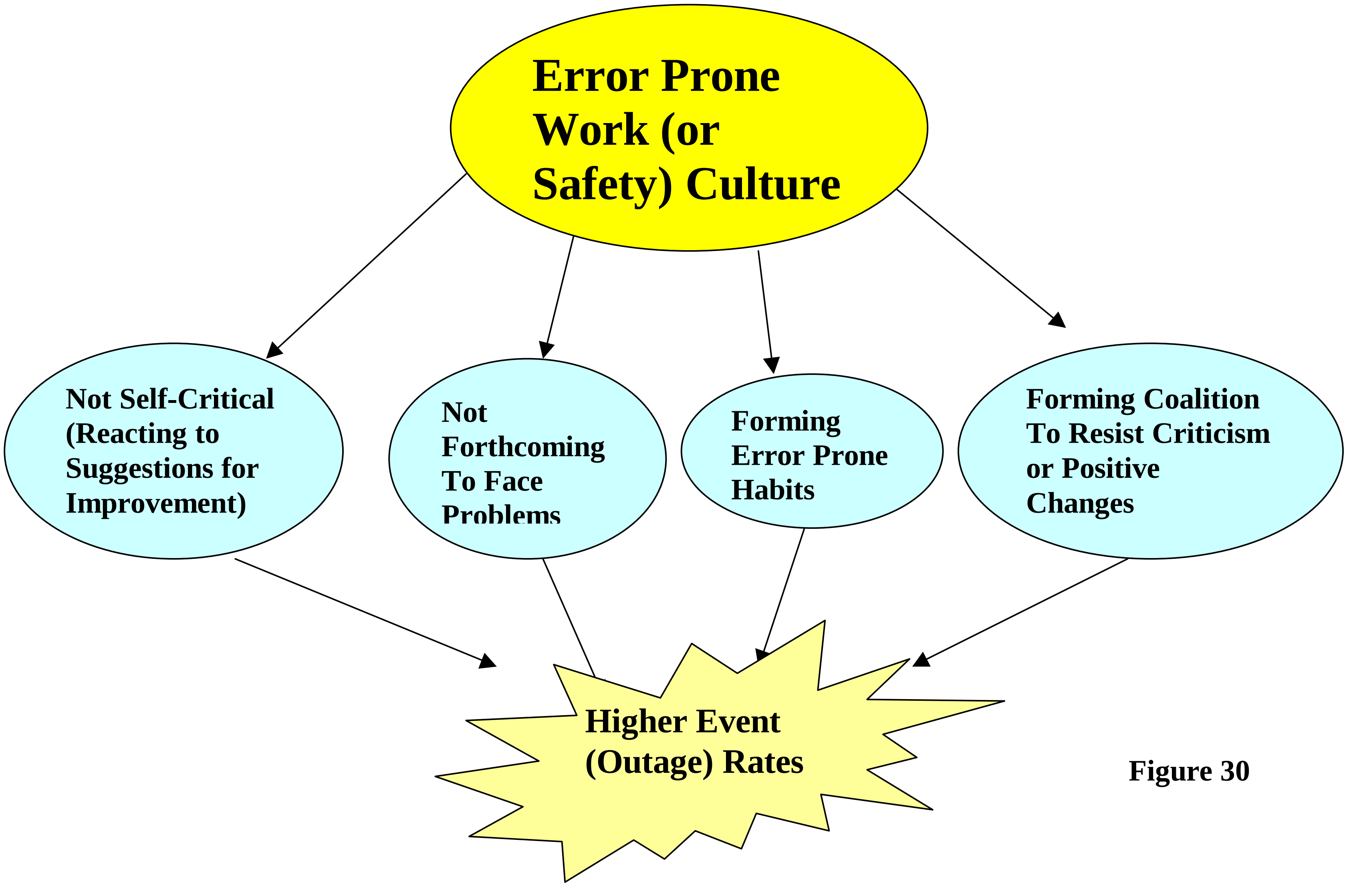


Figure 30

communication technique has been formed over time. This habit (not repeating back in critical communications) is very human error prone.
- Over 140 human errors occurred throughout the event. The large number of errors revealed by a single event indicates that error prone work habits have already been formed by a poor work culture.

Performance Improvement International's research has shown that poor work culture tends to increase the event rate over time. Unless there is a consorted effort to intervene and to improve the work culture, the human error rate will continue to rise and worse events will occur.

Work culture improvement is not an easy task. It takes management's real commitment to intervene with a poor culture and turn it around. In general, for an organization of a size similar to PG&E's transmission and distribution units (~1,000 staffers), it takes about one year to turn the work culture around.

Three steps are usually needed to turn around a poor work culture. The first step is to understand the severity and the spread of the cultural issues through a quantitative culture survey. The second step is to understand which critical component of the work culture affects future human error rates in which organization is substandard. The second step helps the senior management to focus on the cultural problems in organizations that truly need improvement. The third step is rapid intervention through re-training, management realignment, and accountability.

RECOMMENDATION ON WORK CULTURE IMPROVEMENT

It is recommended that PG&E perform an independent work (or safety) culture survey that identifies the severity and spread of the work culture problems and report the survey results back to the California Public Utilities Commission for assessment before June 1, 1999. (Recommendation OFI-21.1)

It is recommended that PG&E institute a work culture improvement program that corrects the identified work culture problems through training, management realignment, and accountability. (Recommendation OFI-21.2)

It is recommended that PG&E repeat the quantitative culture survey one year after the first survey and report the results (improvement) to the California Public Utilities Commission for assessment. (Recommendation OFI-21.3)

It is recommended that PG&E train its work force with human error reduction techniques that can help workers to recognize various error traps and to avoid the types of errors that occurred throughout the outage. The types of errors that should be covered in the training include, but are not limited to, the following:

- Management control errors
- Command and control errors

- Review errors
- Operator errors
- Maintenance errors
- Procedure preparation errors
- Decision errors
- Communication errors
- Problem solving errors

(Recommendation OFI-21.4)

INADEQUATE PROCEDURE AND PROGRAM DEVELOPMENT PROCESS

The investigation team believes that many procedural problems are the result of an inadequate development process of procedures and programs (P&Ps). The procedure and program (P&P) development process at PG&E developed many error prone procedures which, in turn, induce workers into making errors in the field.

Figure 31 shows five procedures or programs that are error prone. Each of the five procedures or programs induced errors during the San Francisco outage. The following are a few examples:

Post Installation Testing –

- The Auto Transfer Scheme of several recloser breakers did not work and caused an extra 90 minutes of outage for about 6% of the consumers. This deficiency should have been detected by a post-installation test.
- The SCADA system has no battery back-up power. This deficiency should have been detected by a post-installation test.

Clearance Procedure-

- The clearance procedure allows abnormal status of relays not to be reviewed before removal of the clearance. Had the clearance procedure required a review of all abnormal operations within the clearance boundary before reporting off, the abnormal status of differential relay 402 would have been noticed.
- The clearance procedure allows the grounds not be counted (in numbers) and reported to the operator before reporting off the grounds.

Grounding manual –

- The grounding manual was written with many vague terms, such as using “It is recommended” versus “It is required” to convey a hard-and-fast requirement.

Post-work testing –

- The post-work testing procedure excludes testing on bus. This exclusion allowed the Bus 2 Section D not to be tested after extensive reconductoring work. Had the bus been tested, the unremoved grounds would have been detected and removed.

Switching log preparation program-

INADEQUATE PROCEDURE DEVELOPMENT PROCESS IS AN UNDERLYING CAUSE FOR MANY PROBLEMS…

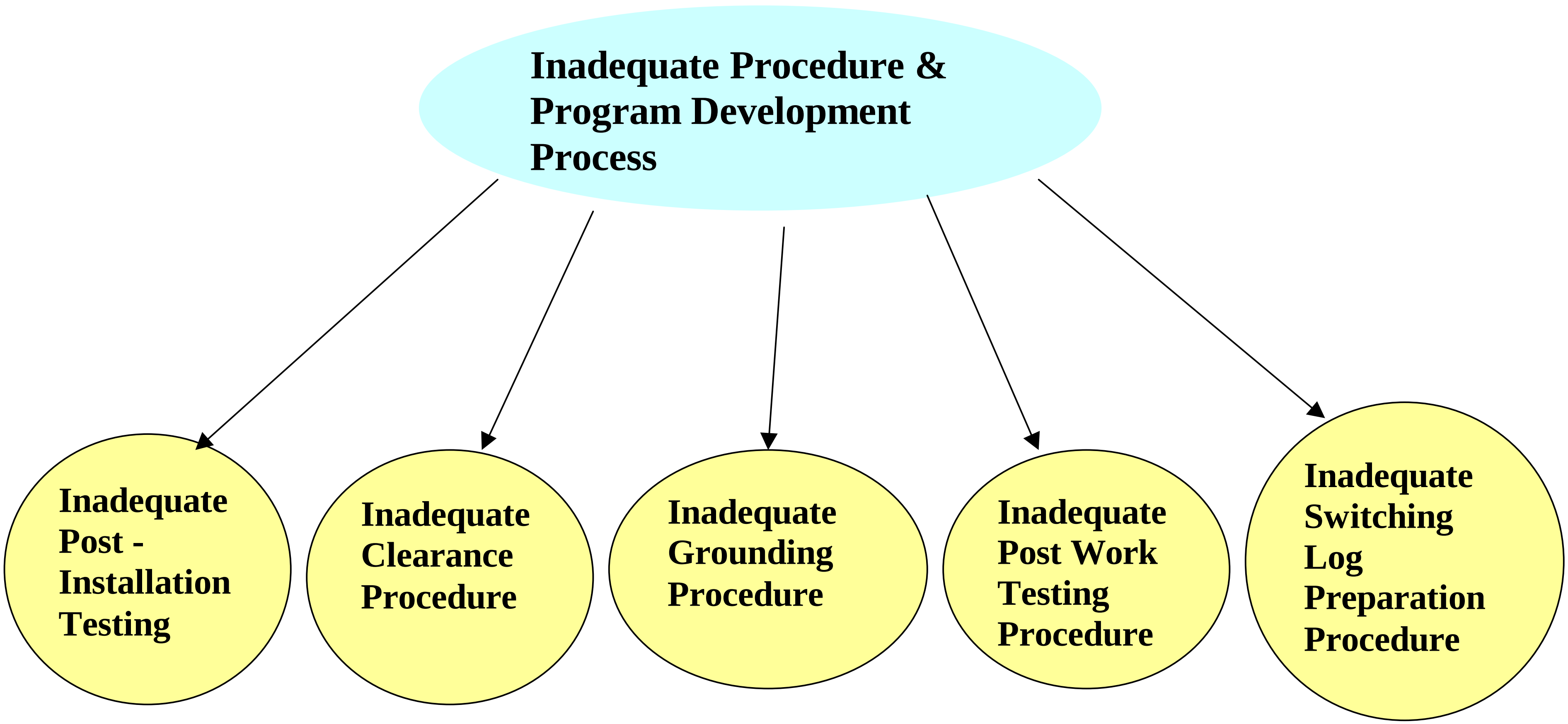


Figure 31

- The program allows the operators to used previously used switching logs and to modify them for new application without pointing out and compensating for the human error traps (such as check for changes, configuration changes, assumptions, etc.).

To understand the extent of human error proneness, the investigation team used its procedure error rate estimation technique to predict the ground removal problem. The error rate of complying with the Ground Manual is estimated to be 15.6%. That is, there is a 15.6% probability that the requirements in the Grounding Manual will not be followed. Assuming that only 10% of these errors are related to failure to remove grounds, it is estimated that the probability of failure to remove grounds is 1.5%. That is, for every 66 grounds installed, there is one chance that the ground will not be removed.

Based on past experience, the investigation team believes that the error rate of the existing grounding procedure is at least a factor of five higher than desired for a critical procedure. For a typical procedure, the general error rate is between 0.5% to 3%, versus 15.5% for the PG&E Grounding Manual.

RECOMMENDATION ON REDUCTION OF ERROR PRONEESS OF PROCEDURES AND PROGRAMS

It is recommended that PG&E develop and retain capability to assess and reduce human error proneness of procedures and programs. (Recommendation OFI –22.1)

It is recommended that PG&E review all existing critical procedures, including clearance procedure, Grounding Manual, post work test procedure, post-installation procedure, and switching log preparation procedure, in terms of its intended scope and error proneness. An improvement in these procedures will decrease the likelihood of inducing events or human errors. (Recommendation OFI-22.2)

It is recommended that PG&E evaluate the back-up power availability for the SCADA system and other systems needed to restore power during a prolonged outage. (Recommendation OFI-22.3)

PREVENTION VERSUS CORRECTION

It is easier and less costly to prevent a prolonged outage than to correct a prolonged outage. To prevent a prolonged outage, it is common to perform an integrated vulnerability analysis (IVA) which not only examines grounding errors, but examines all other possibilities (or scenarios) that may result in a prolonged outage in San Francisco. The possibilities that are likely to occur are analyzed and prevented with the following positive preventive measures:

- Fewer human error inducers
- Stronger barriers to prevent events
- Equipment enhancement to contain consequences

Likely scenarios that may cause San Francisco outages are those scenarios that involve the following:

- Error prone activities
- Error prone procedures
- Equipment failures that are likely to be induced by operators and maintenance

RECOMMENDATION TO IMPLEMENT INTEGRATED PREVENTIVE MEASURES

It would be prudent to perform an integrated vulnerability analysis (IVA) on the San Francisco electric supply in order to determine all the vulnerable points that could be eliminated with preventive measures. (Recommendation OFI 23.1)

It is recommended that PG&E perform an Integrated Protection System analysis to ensure that the existing protection system is adequate to protect the vulnerable areas identified in the IVA. (Recommendation OFI 23.2)

FUTURE OUTAGE PREVENTION AND INVESTIGATION

During the two month investigation, the investigation team observed the following:

- Many state and federal agencies are involved in regulation or oversight of different parts of the generation, distribution, and transmission system.
- Without an integrated, independent investigation, the root causes of outages are hard to find and improvement may be sub-optimized. Under the present regulated system, the incentive for a utility to perform such a full scope, in-depth investigation is not high.
- Within a utility, the transmission, distribution, and generation departments do not learn lessons from each other.
- Among utility distribution companies, lessons learned or good practices from one utility are usually not shared with other utilities.
- Very few "preventive" measures, such as analyzing and improving error prone processes and work practices to reduce outage probabilities, are in place to prevent outages.

To ensure long-term reliability of the electricity supply to consumers, it seems reasonable that future outage events in which the consequence exceeds a certain threshold (such as exceeding 100,000 consumer-hours in one continuous outage) be investigated by an independent board, which would be capable of performing full scope investigations. The board would ensure that lessons learned and good practices are shared among utilities. The board could also be chartered to coordinate with various state and federal agencies to ensure that measures to prevent outages are in place in generation, distribution, and transmission, and are not sub-optimized.

RECOMMENDED ACTIONS

Figure 32 shows the concept of cost-effectiveness of implementing the OFIs to prevent the recurrence of an outage similar to the one that occurred on December 8, 1998 in San Francisco. The total losses of the San Francisco outage are estimated by the investigation team to be between $200 and $400 million. The average value is $300 million.

As a prudent practice, it is reasonable to spend up to 10% of the consequence to prevent recurrence. This means that it is reasonable to spend up to $30 million to prevent the recurrence of a prolonged San Francisco outage.

To ensure the cost-effectiveness of the OFIs, the investigation team requested several individuals who have extensive experience in implementing the recommended actions to estimate the costs of each recommendation. The total cost to implement all recommended actions is estimated to be $10 to $20 million. The most expensive actions are related to those corrective actions that are needed to turn around the work culture and to set up the human performance control loop.

The recommended actions are summarized in the Recommendation Matrix, as shown in **Figure 4**. The benefits of the recommended actions, as an aggregate, are to prevent recurrence. The team estimates that with the recommended actions, the probability of recurrence of another San Francisco prolonged outage will be reduced by a factor of over one hundred. Moreover, if a prolonged San Francisco outage recurs in the future, the recovery time will be reduced to no more than three hours.

Because there are so many combinations of human errors and equipment failures that can result in recurrence of a prolonged San Francisco outage, the investigation team believes that without addressing the underlying causes, the probability of recurrence cannot be effectively reduced.

CONCEPT OF COST-EFFECTIVE SPENDING ON RISK REDUCTION FOR A MAJOR ELECTRICAL OUTAGE

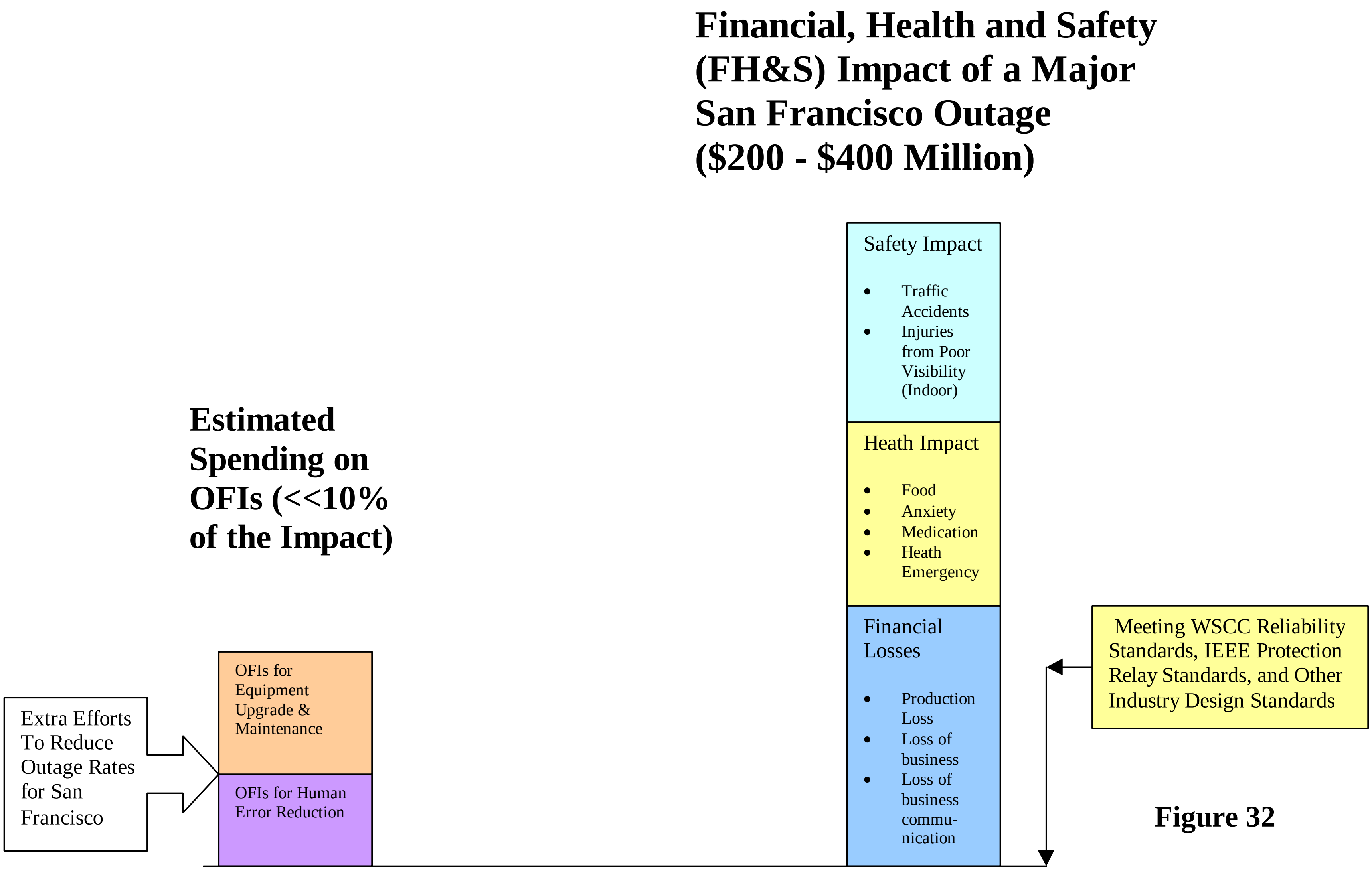


Figure 32

APPENDIX C

Common Cause Analysis of San Francisco Outage

PURPOSE

The investigation team uses common cause analysis to verify the validity of the OFIs identified in this report. The common cause analysis, by itself, has also been used by the investigation team to determine the underlying causes if data is available from many other outages.

This analysis categorizes the failures in three dimensions. These three dimensions are:

- Human error types (i.e., skill based, rule based, or knowledge based errors)
- Human error failure mode (such as inattention to detail, misjudgment, etc.)
- Organizational or programmatic failure mode (such as inadequate program scope, inadequate interface among programs)