Outage Investigation
Larkin Substation Outage on April 21, 2017

Exponent®

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on April 21, 2017

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Acronyms and Abbreviations

DCC	Distribution Control Center
DO	Distribution Operations
FD	Fire Department
GC	General Construction
IC	Incident Command
LTC	Load Tap Changer
RTU	Remote Terminal Unit
SCADA	Supervisory Control And Data Acquisition
UG	Under Ground

Limitations

At the request of Pacific Gas & Electric Company (PG&E), Exponent conducted a causal assessment of the Larkin substation outage in San Francisco, CA on April 21, 2017. Exponent has investigated specific issues relevant to the event as requested by PG&E. The scope of services performed during this investigation, as well as our findings as described herein, may not adequately address the needs of other users and any re-use of this report, conclusions, or recommendations presented herein are at the sole risk of the user.

The findings presented herein are based on observations and information available at the time of the investigation. This report may be supplemented to expand or modify our findings based on additional work or review of additional information. Thus, if new data become available or there are perceived omissions or misstatements in this report, we ask that they be brought to our attention as soon as possible so that we have the opportunity to fully address them.

Executive Summary– Direct Cause and Lessons Learned

PG&E is investigating an outage event at the Larkin substation that occurred on Friday, April 21, 2017, which resulted in an outage in downtown San Francisco (the incident). The objective of this effort is to determine the cause of the substation outage as well as to identify lessons learned from the emergency response. The conclusions herein are prepared with the information available to date. We reserve the right to supplement or amend this document should additional information become available or should additional testing or analysis provide further insight.

Incident Investigation

Problem Statement

On April 21, 2017 at approximately 9:06am, an outage occurred at the Larkin substation due to a fire at the station resulting in the loss of electric power to approximately 88,000 customers in downtown San Francisco.

Findings and Observations

1. An arc flash incident occurred in a 12 kV feeder circuit breaker cabinet in the Larkin substation (incident cabinet) at 9:06am on April 21, 2017. The arc flash resulted in a fire that caused additional thermal and smoke damage to the Larkin substation. Based on the witness accounts of personnel at the substation, there was no prior sign of a problem at the failed breaker cabinet before the incident, and the incident occurred without warning.

2. The incident breaker did not operate, likely because the breaker cabinet was damaged due to the arc flash. The substation protection scheme detected the fault and tripped in less than one second, as designed. This resulted in the loss of the Larkin substation and all associated customer service.

3. The failure most likely originated near the top of the incident circuit breaker at the connection points.

4. The most likely cause of the failure was an abnormal configuration of the station that persisted for approximately 27 hours prior to the incident. The abnormal configuration resulted from the closing of a second circuit breaker at the incident feeder after a scheduled switching operation, approximately 27 hours prior to the incident. This configuration effectively made the two station bus bars in parallel and resulted in overstressing the electrical components between the two bus bars at the incident feeder, including the incident circuit breaker connections.

5. The Supervisory Control and Data Acquisition (SCADA) system detected the abnormal configuration of the station approximately 27 hours prior to the incident and created an alarm at the Distribution Control Center (DCC). Although the alarm was high priority, it was not audible. It would have been easy for the distribution system operator to miss this

alarm due to the large number of non-audible alarms that the system receives during daily operations.

6. The SCADA system also reports the status of all the breakers inside the station, which would have made the abnormal configuration visible to the distribution operation (DO) prior to the incident. However, it would have been easy for DO to miss the abnormal configuration because the breaker status was reported in a tabular form for the Larkin station rather than in a more user-friendly graphical (single-line diagram) form.

7. Detection of the abnormal configuration using the breaker status in the Larkin station was even more difficult for DO because the SCADA system in that station did not differentiate between a breaker "close" status and an out of operation or "racked out" breaker status due to the hardware design in that particular station.

8. The abnormal configuration resulted in overstressing and eventual failure of the connection to the switchgear at the top of the incident breaker. This failure led to an arc flash followed by a fire inside the incident breaker cabinet. This is based on the following:

    a. SCADA data log shows that both breakers on the incident feeder were closed the day before the incident. This is a known abnormal operational configuration that resulted in the two station bus bars being in parallel and causing excessive currents through the electrical components between the bus bars at the incident feeder.

    b. Recorded data of the position of the Load Tap Changers (LTCs) at the station transformer banks show increasing voltage deviations at the two station bus bars immediately after the station's configuration became abnormal. This translates into an increase in current through the electrical components between the bus bars at the incident feeder, including the incident circuit breaker connections. The voltage deviation increased to a maximum value just before the failure on the morning of April 21, 2017.

    c. Estimated currents through the breakers of the electrical components between the bus bars at the incident feeder reached approximately 1800 Amperes. This exceeded the rated current of the feeder breakers and their components. The feeder breakers and their components are rated for 1200 Amperes.

9. The following is relevant to the cause of the abnormal configuration in the station approximately 27 hours prior to the incident:

    a. Equipment malfunction leading to the closing of the second breaker due to the network automatic transfer mechanism and network group close mechanism has been ruled out. This is based on a review of the system design and implementation, and in-station testing by PG&E.

    b. Human influence causing inadvertent remote closing of the second breaker at the incident feeder has been ruled out. This is based on the SCADA control log, which does not include a "control select" or "control execute" command prior to the recorded closing of the second breaker, indicating that a remote command was not executed by DO for such operation.

c. Human influence causing inadvertent manual closing of the second breaker has been ruled out. This is based on the station logbook and security camera footage showing that the switching personnel inside the station signed out of the station approximately 10 minutes before the recorded time of the closing of the second breaker.

   i. Switching personnel inside the station performed manual operations according to the switching log in coordination with the system operators before handing over the switching activities to DO for further remote switching operations the day before the incident.

   ii. Exponent has not found any requirements for the switching personnel to remain at the site for the remote switching operations, although, it may be prudent to do so and to check for correct remote operations according to the switching log.

d. There have been reports of other feeder breakers being simultaneously closed in the past, which were corrected upon discovery. However, no evidence of a SCADA equipment malfunction has been discovered that may explain the presence of the incident abnormal condition.

10. The most likely cause of the abnormal configuration of the station prior to the incident is a malfunction of the remote operating and control systems, which led to closing of the second circuit breaker. This conclusion is based on review of the control diagrams and wiring inside the station, engineering assessment of associated circuits, and laboratory testing of the breaker control switch.

    a. The remotely operable control switch of the second circuit breaker was removed from service and examined/tested in the laboratory. The tests revealed that: (1) some of the switch characteristics have changed over time, likely due to aging; (2) the switch is vulnerable to some system transients that could result in closing of the switch.

    b. PG&E has reported modifications in the SCADA system to immediately detect and report paralleled bus bars via feeder breakers inside Larkin station.

    c. PG&E has plans to replace the old Larkin station with a new Gas Insulated Substation.

Causal Analysis

The results of the causal analysis indicated the following causes of the event:

- Primary cause: Equipment malfunction due to age and wear. Based on the elimination of other possible causes of breaker closure, the malfunction of the remote operating and control system is the most likely cause of the CB 1121/12 closure and placing the circuit in a parallel bus configuration.

- Secondary cause: Human factors design of the SCADA monitoring and alarm system that did not provide for easy identification of the parallel bus configuration. For the Larkin substation, the breaker closure function is a Priority 9 alarm and it does not include an audible alarm. In addition, the visual cues for the breaker closure included an alarm list and a tabular configuration of the station. There was no graphical representation of the breakers status for the Larkin station. Additionally, the SCADA system in that station did not differentiate between a breaker "close" status and an out of operation or "racked out" breaker status due to the hardware design in Larkin station.

Actions Initiated Since Incident

PG&E has made developments in the SCADA monitoring and alarm system since the incident to help with the human factor and ease of identification of similar abnormal conditions in the future. The developments include replacing the tabular report of the breakers status in Larkin substation with a more user friendly graphical representation. The new graphical representation of the breakers status is in the form of the single-line diagram on the SCADA screen in the DO control center. Additionally, PG&E has plans to develop a separate alarm system to create additional alarms in the case of abnormal parallel bus bars in the Larkin station using the SCADA software and existing SCADA signal from the Larkin station.

Corrective Actions

Corrective actions recommended to address the causes of the event include the following. It should be noted that there is an on-going project to upgrade and replace the switchgear in the Larkin Station that will address equipment age, wear and obsolescence issues.

1. Replace the remotely operable switch for the second circuit breaker (CB 1121/12) at the incident feeder inside the station (completed).

2. Develop an improved approach to identify and alarm the parallel bus configuration via feeder breakers, including:

    a. Reevaluate the SCADA alarm categories, priorities of the alarms, and which alarms should be audible.

    b. Replace the existing tabular reports of the breakers status in the Larkin station with a graphical (single-line diagram) report for ease of identification (completed).

    c. Provide a separate detection and alarm system using SCADA for the closed feeder breakers causing a parallel bus bar in the Larkin station (in progress).

Extent of Condition

At the Larkin substation, PG&E occasionally utilizes a parallel bus configuration via bank breakers for short durations. On those occasions, slight voltage differences between the two bus bars add stress at the bank breakers, which have higher current-carrying capacity. The feeder breakers may also be closed on those occasions, providing an alternate parallel path between the bus bars without putting too much stress on the circuit components at the feeder.

The cause of this incident required two specific conditions: a parallel bus configuration via feeder breakers only, and a relatively long duration in this configuration that resulted in development of a high circulating current. The circulating current at the incident feeder increased for approximately 27 hours and reached a maximum value before the incident occurred. If the parallel configuration via feeder breakers is identified in a timely manner, then, this type of event can be precluded.

Exponent recommends that PG&E consider reviewing the other stations that utilize a similar switching and SCADA reporting scheme to determine whether the above recommendations are applicable to those facilities.

Better tools to identify the parallel bus configuration via feeder breakers may exist at other substations with similar configuration. These tools include graphical representation of the breaker configurations and different SCADA hardware to differentiate between a racked out breaker and a closed breaker status. For the Larkin station, operators are aware that the parallel bus configuration is not a standard operating mode, except for short duration and only in particular circumstances. However, better SCADA tools for this station could help with ease of identification of abnormal operational configurations such as parallel bus bars.

Emergency Response Lessons Learned

The Larkin Substation outage occurred at 9:06am on April 21, 2017. The outage event was concluded at 4:46pm that day when the final customers were restored. The key outcomes of this event included:

- All personnel at the substation exited safely after the event and there were no injuries to any PG&E personnel, Fire Department personnel, or members of the public at the substation during the event.
- The fire was extinguished successfully and the substation was returned to service.
- Customers were restored both before and after PG&E was able to re-enter the substation after the fire was extinguished, and customers were being restored as PG&E was in the process of entering the substation and after the substation was returned to service. Given the work to return the substation back to service, the restoration time appears reasonable.

An assessment of the Larkin outage response was performed to identify lessons learned and to provide recommendations for continuous improvement.

Evaluation of Emergency Actions to Identify Lessons Learned

There are two primary activities related to the outage restoration: (1) emergency response for the substation fire; and (2) PG&E customer restoration activities.

1. The emergency response to put out the fire in the Larkin Substation

The emergency response time frame is defined as starting with the beginning of the outage and fire and ending with the Fire Department clearing the substation for PG&E's reentry. The emergency response activities from PG&E's perspective are governed by Work Procedure TD-3320P-03, "Fire Entry Procedure for an Indoor Substation". This procedure is directly applicable to the emergency response at Larkin and spells out the duties for PG&E personnel during this time. The emergency response time frame is divided into three major steps: (1) start of incident until arrival of Fire Department; (2) arrival of Fire Department until their entry into the substation for firefighting activities; and (3) Fire Department entry into the substation until an all clear is given for PG&E reentry

Start of Incident to arrival of Fire Department (9:06 to 9:32am):

The assessment indicated the following key observations during the initial step:

1. The incident arc flash (incident) occurred at 9:06:06am on Friday, April 21, 2017.

2. Four personnel present in the substation (three substation construction electricians and a Canus Corporation contract inspector), heard an explosion, and began evacuation. Those present within the substation evacuated safely through the front entrance per safety procedures and called their supervisor while exiting by 9:07:51am. Within the first 10 minutes, the employees evacuated, ensured everyone was out and safe, contacted DO and, upon noticing that the fire department may not have been automatically notified, started to make 911 calls.

3. Other personnel were present outside the main entrance of the substation (another Canus contract inspector, a cable splicer acting as temporary foreman and his crew from the underground) on Larkin Street.

4. There was a 22-minute delay in fire department notification from the start of the incident as a result of the confluence of three independent events:

    i. The third party fire alarm monitoring company reported that they did not receive an automated notification of the fire due to an error in the fire alarm panel's communication system and thus did not call the fire department.

    ii. The DO personnel at the Distribution Control Center did not call 911 upon receiving the fire alarm despite the requirements of the Work Procedure TD-3320-P03. It appears that there was a miscommunication regarding whether the Fire Department had been called and the DO personnel were under the impression that the Fire Department was on its way to the substation.

    iii. The substation electricians standing outside of the substation tried but did not get through to the 911 operator; they ultimately called the front desk equivalent of the San Francisco Fire Department which then conveyed their message to dispatch.

5. The Fire Department were dispatched at 9:28am and first arrived on the scene at 9:32 am (with a fire engine at the front of the station and a truck at the rear of the station.

Arrival of Fire Department to entry into the substation (9:32-9:46 am):

The assessment of this second part of the emergency response activities indicated the following key observations:

1. Approximately coincident with the arrival of the first-in fire engine at 9:32 am, a restoration cableman arrived in response to the outage alert on the outage management tool (OMT/OIS). The cableman was informed by the substation personnel present outside the front entrance that no one was allowed to enter per instructions of their supervisor, who was en route to Larkin. This was disputed by the cableman, who then assumed the role of Incident Command (IC) and attempted access through the front door of the substation, but the badge reader was not functioning and the proper keys were not available. At this time, a responding restoration troubleman (serving as the rotational supervisor) arrived and moved to the rear of the building with the cableman.

2. Around 9:38am, a contract inspector used his badge to open the rear stair door. Around the same time a firefighter radioed that PG&E employees wanted to enter. Around 9:39:20am, fire department personnel at the back radioed that the rear door was open and that the highest ranking PG&E employee was with them.

3. At 9:43:29am, DO told a responding substation maintenance electrician to tell the fire department that the whole station was de-energized from the sources, and so, once they can get in, they can extinguish the fire.

4. Sometime after 9:38am and before 9:46am, the cableman, the troubleman, and two other PG&E employees entered the Larkin substation to assess the fire. Smoke was reportedly present at this time. The troubleman came back out to inform the fire department that only one cell was involved. The cableman reportedly went through the building on the inside towards the front door and was present when the fire department entered after forcing open the front door, at approximately 9:46am. PG&E procedures (TD-3320P-03) prevent PG&E personnel from entering a burning, or potentially burning, substation.

5. During this time (before 9:46am), an electrician sent to Larkin by the Crew Lead Electrician to act as the first responder, arrived and assumed the IC role. At the request of the substation maintenance supervisor on the phone, the electrician instructed the fire department to retrieve the fire pre-plans and the station logbook from inside the front door.

6. The fire department entered the back and the front of the building around the same time, shortly after the arrival of the electrician, the designated PG&E first responder. Around 9:46am, approximately 14 minutes after first arriving on scene, the fire department opened the large roll-up door at the back and reported a visual on a trash-can size fire after stepping in the doorway about 20 feet. Around the same time, other

firefighters made entry through the front main door. The fire panel logs indicated that the silence button, which is located near the front door, was activated 38 seconds after the fire department reported making an entry through the front main door.

7. Opportunities for improvement from this time frame include:

   i. The role of IC was not clearly understood by all personnel at the site during this time.

   ii. The cableman responding to the incident assumed the IC role, but did not communicate with DO.

   iii. The cableman and other restoration personnel entered the burning substation along with other restoration personnel. The IC role includes communication with DO and prevention of PG&E employees entering a burning, or potentially burning, substation.

While there are opportunities for improvement during this initial time from the start of the event until the Fire Department made entry into the substation, this initial period had a small impact on the overall duration of restoring all customers back to service.

Fire Department entry until all clear (9:46 am-12:12 pm):

The assessment of this third part of the emergency response activities indicated the following key observations:

1. At 9:53am, photographs were taken inside the substation on the troubleman's cell phone showing flames inside the Y1121 cabinet. At 9:54 am, another cell phone photograph taken shows firefighters fighting the fire with extinguishers.

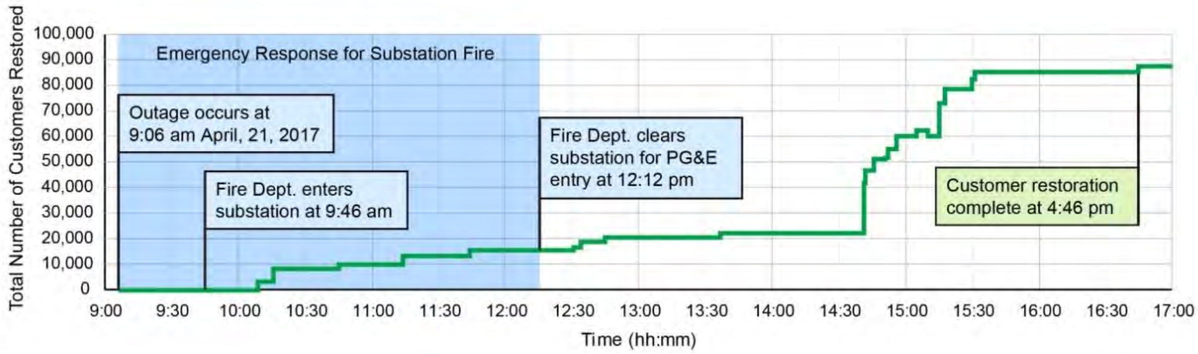
2. By 9:57 am, firefighters radioed that they may want the CO_2 truck unit responding because they were able to knock the fire down, but the fire seemed to be coming back.

3. At 11:17am, a PG&E employee at the Larkin Station informed DO that the fire was extinguished and that ventilation was underway. By 12:12pm, the fire department allowed PG&E employees to enter the Larkin substation for restoration.

4. Around approximately 12:12 pm, the Substation Maintenance Superintendent and other PG&E personnel went inside with the Fire Department. They restored station service from 1104 source at 12:15pm, and initiated the substation restoration process.

2. Customer restoration activities that can be performed with switching from other locations and ultimately completed after entry into the Larkin Substation

PG&E initiated restoration activities shortly after the outage began. The graph below shows the time frame for customer restoration.



Key observations from the customer restoration include:

1. During the emergency response period, PG&E restored customers through alternate sources by switching outside of the Larkin Substation.

2. Around 2:30pm, all bank breakers and tie breakers were checked, banks 2, 4, and 6 were isolated, and banks 1 and 5 were energized.

3. Bank 3 would not energize due to a problem with its low side breaker. Between 2:38pm and 2:56pm, the 115 kV bus was returned to normal operation and Bus 1 sections D, E, and F were energized.

4. At 3:10pm, smoke was reported again and the Y3 network was opened for further investigation. By 4:25 pm, the bank 3 low side breaker was replaced, switches were opened in the field to isolate back feed on Y3, and the Y3 network was tested and reenergized.

5. The remaining customers were restored by 4:46 pm, 7 hours and 40 minutes after the incident, and 4 hours and 34 minutes after PG&E employees were first allowed back in to the station by the fire department.

Lessons Learned and Recommendations

The requirements for emergency response due to a fire in a substation are defined in PG&E Procedure TD-3320P-03 “Fire Entry Procedure for an Indoor Substation”. The lessons learned are based on an evaluation of the procedure and the effectiveness of its application. The lessons learned are primarily focused on the emergency response from identification of fire to the fire department entering the building.

Lesson Learned	Recommended Corrective Action
It appears that the protocol for the assumption of the PG&E IC role, as outlined in TD-3320P-03, section 2.2, “Fire Entry Procedure for an Indoor Substation”, was not clearly understood by some of the PG&E’s restoration personnel who responded to the incident. As a result: b. Multiple PG&E personnel initially assumed the role of IC concurrently. c. The cableman responding to the incident assumed the IC role, but did not communicate with DO d. The cableman and other restoration personnel entered the burning substation along with other restoration personnel. The IC role includes communication with DO and prevention of PG&E employees entering a burning, or potentially burning, substation.	1. Perform a review of the effectiveness of the fire entry procedure for indoor substations and update the procedure as appropriate. 2. Update training materials and provide training to the PG&E employees, as appropriate.
The TD-3320P-03 procedure assumed certain scenarios and did not address others. Specifically, the procedure assumes that the station would be unmanned at the time of the incident and that the PG&E first responder would have to be dispatched. This turned out not to be the case during this incident as personnel were already present on the scene who could potentially have served as first responder.	1. Expand the fire entry procedure to include situations where qualified personnel could be already present at the site.
The third party fire alarm monitoring company reported that they did not receive automated notification of the fire alarm due to an error in the fire alarm panel’s communication system, and did not call the fire department. The alarm panel communication to the monitoring company was last tested successfully during an annual fire system inspection on June 11, 2016 by the third-party monitoring company. The problem with the communication system was identified after the incident.	1. Conduct random audits of the fire alarm panel’s operation. 2. Review communication systems at other facilities managed by the third party monitoring company.
The PG&E IC is required to discuss the fire pre-plans with the fire department, to advise them of hazards, and to communicate information regarding equipment clearances. This role is critical to ensuring timely access to the fire by the fire department. The procedure precludes PG&E entry into the substation until the fire department declares the building safe for entry.	1. Review fire entry requirements with the Fire Department to clarify the requirement that PG&E personnel should not enter the building prior to fire department declaring the building safe. 2. Incorporate these substation fire entry requirements in the joint fire department training exercises.

Lesson Learned	Recommended Corrective Action
The CO2 truck unit was not dispatched to Larkin until approximately 30 minutes after the fire department arrived at Larkin.	1. Coordinate with the fire department to establish the practice of immediately mobilizing the CO_2 unit in the case of substation and switchgear fires, whether indoor or outdoor.
Based on the present procedure, which assumes the station is unmanned, in the case of a substation fire, the fire department could potentially wait for a significant amount of time while a PG&E first responder is dispatched and arrives at the substation.	1. PG&E should consider working with the fire department and other city emergency services to consider the procurement of emergency response vehicles and/or to establish effective emergency escort procedures to improve response time by first responders so that an IC can be established quickly.

Introduction

Problem statement

An incident occurred in the PG&E Larkin substation on April 21, 2017 at approximately 9:06am that resulted in a fire at the substation and a power outage. The outage affected approximately 88,000 PG&E customers in the San Francisco area. Power to all of the customers was restored by 4:46pm on the same day. The outage was due to a fire in a circuit breaker cabinet. The substation protection system was activated, and it de-energized the station as the system is designed to do.

The following is a discussion of Exponent's findings to date. The conclusions herein are based on the information available to date. We reserve the right to supplement or amend this document should additional information become available or should additional testing or analysis provide further insight.

Objectives

PG&E is investigating an outage event at the Larkin substation that occurred on Friday, April 21, 2017 which resulted in an outage in downtown San Francisco (the incident). The objective of this effort is to determine the cause of the substation outage and to evaluate emergency actions immediately following the incident as well as customer service restoration.

Background and Summary of Observations

An arc flash incident occurred in a 12 kV feeder circuit breaker cabinet in the Larkin substation at 9:06am on April 21, 2017. The arc flash resulted in a fire that caused additional thermal and smoke damage to the Larkin substation. Visible damage was discovered at the incident feeder (Y1121) and inside the cabinet where the incident breaker (CB1121/22) is located. Locations of significant damage were at the top of the CB1121/22 breaker (Figure 1); at the "Tee tap" located near the back of the incident cabinet (Figure 2); and, at the cable tray and cables between the circuit breakers CB1121/22 and CB1121/12 in the lower level (Figure 3). A schematic one-line electrical diagram is shown in Figure 4 that summarizes the damage locations at the incident feeder and the likely path of the initial fault current.

The incident circuit breaker was rated for continuous load of 1,200 Amperes and fault interruption time of 8 cycles. A mechanical service test was done on the incident circuit breaker approximately 7 months prior to the incident (9/20/16). The incident breaker had also passed the functional performance test at the same time (see Appendix D). Figure 5 shows the nameplate of a similar circuit breaker (exemplar breaker).

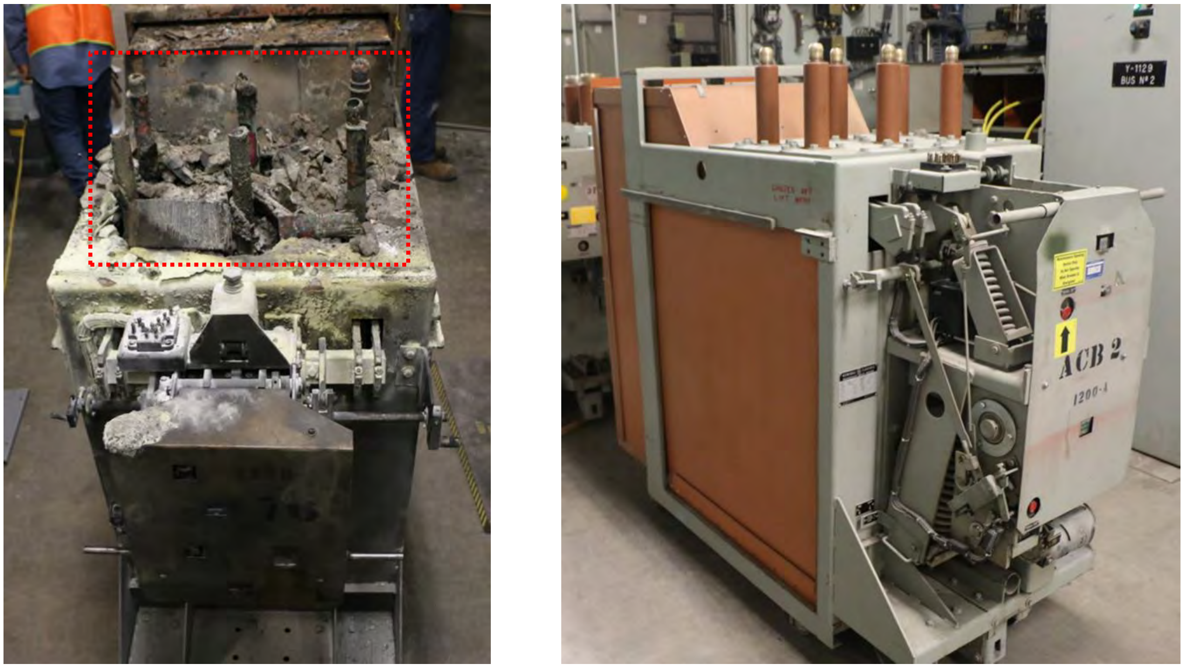


Figure 1. The incident breaker (left) and an exemplar circuit breaker of similar type (right). Most of the damage at the incident circuit breaker is near the top of the incident circuit breaker at the connection points.

Figure 2. Damage at the “Tee tap” near the back of the incident cabinet.

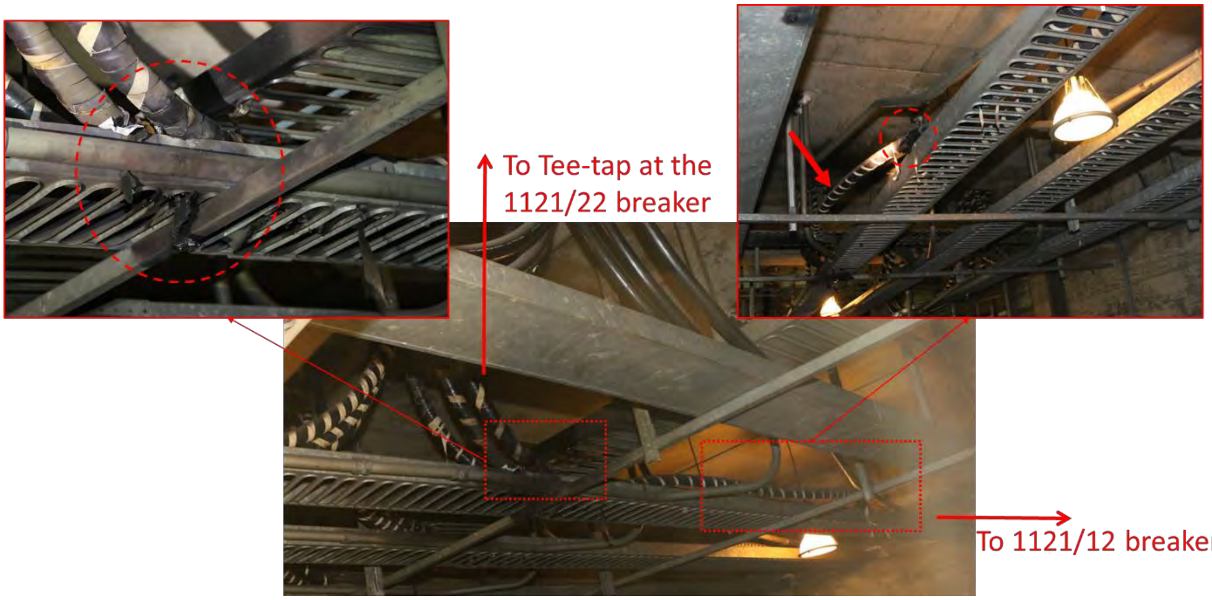


Figure 3. Damage discovered in the cable tray and cables between the two circuit breakers at the incident feeder (Y1121).

[redacted]

Figure 4. One-line diagram showing damage locations at the incident feeder (Y1121), and the likely path of the initial fault current.

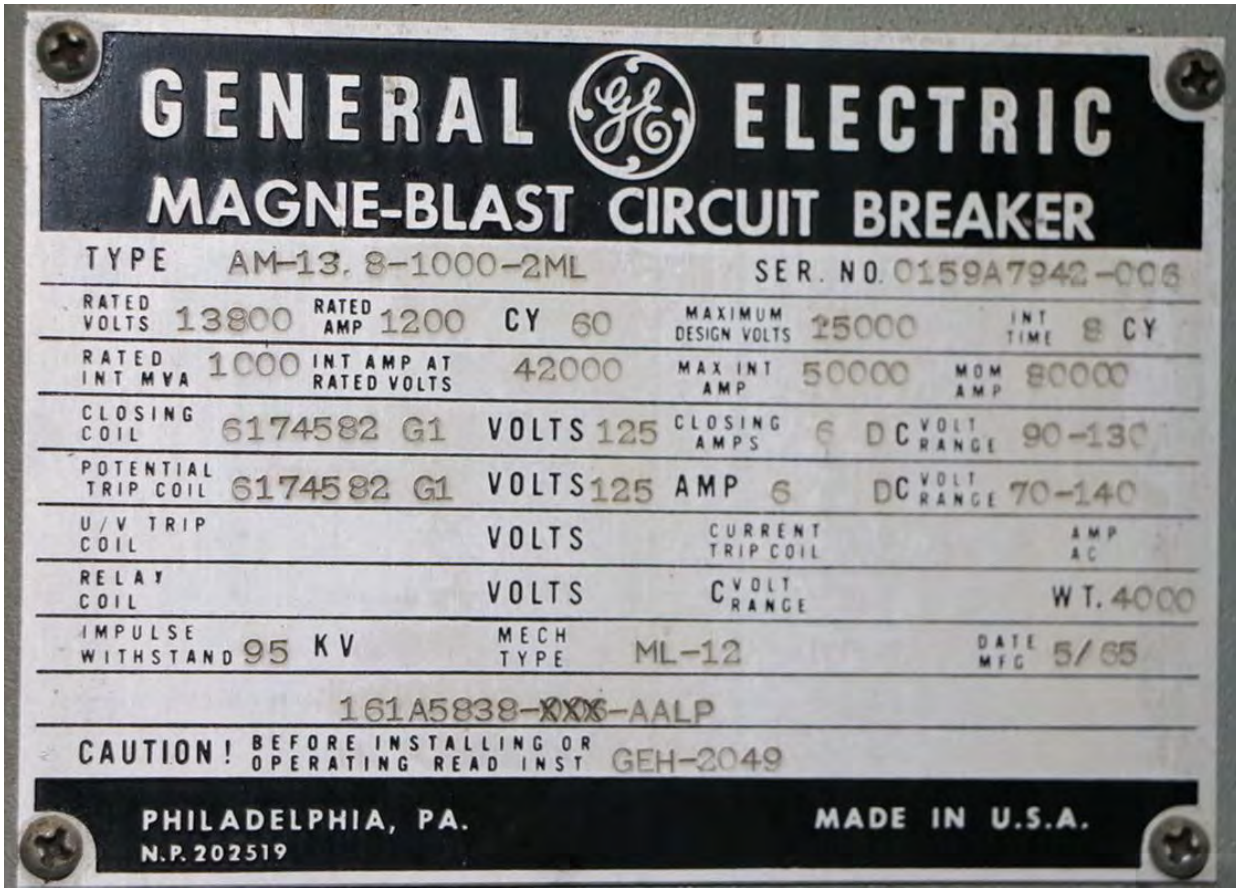


Figure 5. Nameplate of an exemplar circuit breaker.

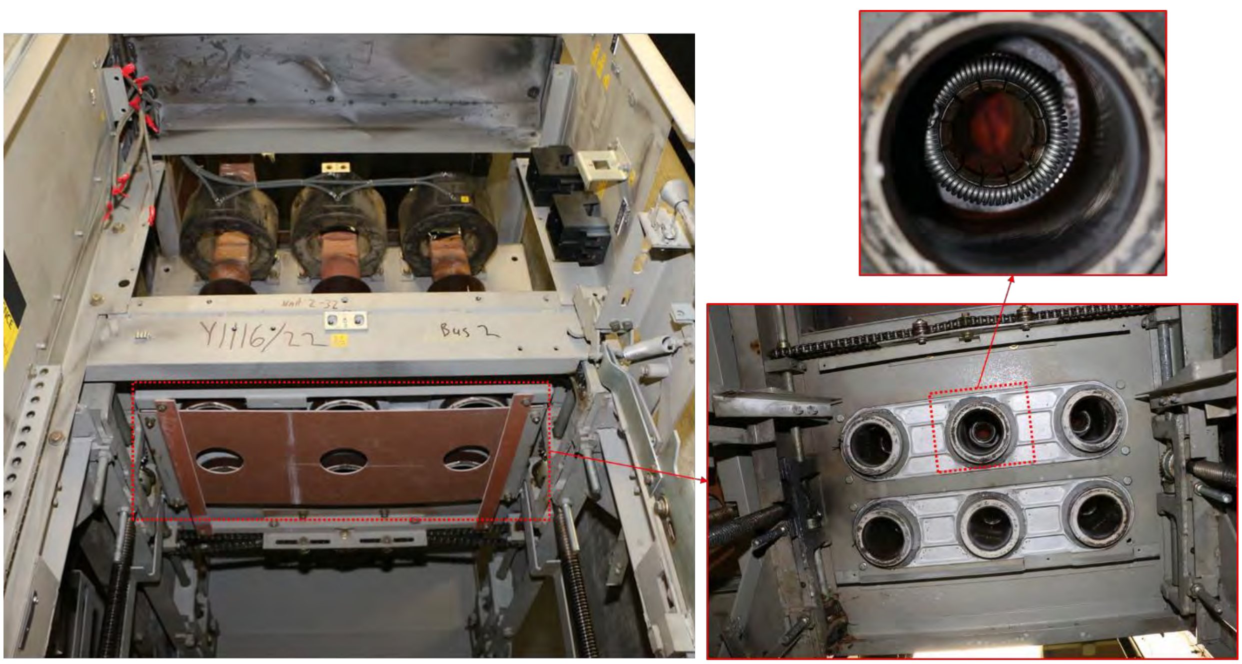


Figure 6. Connections inside an exemplar cabinet at the top of the circuit breaker cabinet.

Figure 7 shows the station configuration at the time of the event. The substation protection scheme detected the fault and tripped in less than one second, as designed. This resulted in the loss of the Larkin substation and all associated customer service. The high-side (115 kV) circuit breakers operated and interrupted the fault. The AY-1, XY-1, and HY-1 transmission lines to the substation de-energized. The AY-2 transmission remained energized, but disconnected from Larkin (open-ended). This line was de-energized via SCADA after the incident for safety. The substation protection operated as designed for this type of fault inside the station.

[redacted]

Figure 7. Station configuration at the time of the incident.

Sequence of Events

The sequence of events leading to the incident started two nights prior to the incident on April 19, at approximately at 10:30pm when clearance was established on Y1121 feeder for a routine maintenance outside the station. By early next morning on April 20, the maintenance work was complete and electricians inside the station started a pre-planned switching operation[1] in coordination with DO to bring the feeder back online. The switching plan consisted of two parts: in-station switching and remote switching. At 5:56 am on April 20, Electrician 1 and Electrician 2 completed the in-station part of the switching and handed the operation over to DO for remote switching. Less than 5 minutes later at 6:00am, the circuit breaker CB1121/22 was closed remotely via SCADA per switching plan. Approximately 9 minutes later, the network auto-transfer function was cut in remotely per switching plan. SCADA logs show that approximately 1 minute later at 6:10am, the circuit breaker Y1121/12 was closed; this was an unintended operation that paralleled the two station bus bars through the Y1121 breakers and

1 Switching log number 17-0035489.

put the station in abnormal configuration. The station remained in abnormal configuration until approximately 27 hours later on April 21, at 9:06am, when the incident occurred.

An electric fault occurred in Larkin at the time of the incident. The fault activated the feeder protection that sent a trip signal and opened the CB1121/12 breaker The CB1121/22 did not operate and the fault continued until it was interrupted by the high-side circuit breakers in less than 1 second. This resulted in the total loss of power and the substation went dark. The fault resulted in fire and smoke in the station. Emergency actions followed and restorations started shortly after the outage began. The substation was back online and all PG&E customers restored by 4:46pm. Figure 8 shows a high-level timeline of the events.

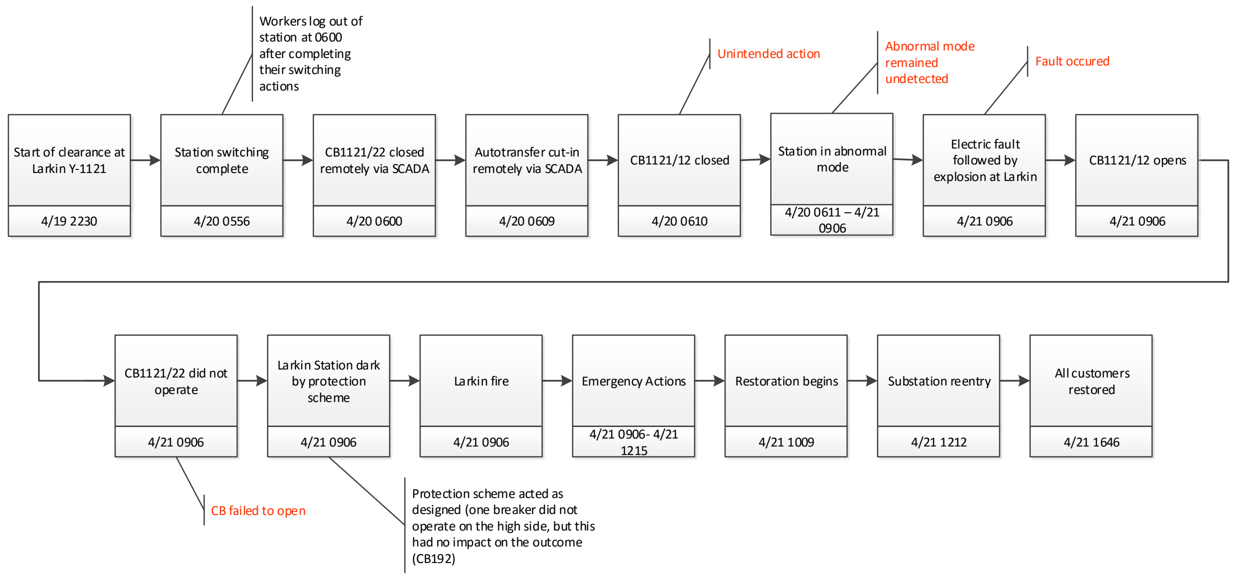


Figure 8. A high-level timeline of the events

The Abnormal Configuration

Figure 9 shows a simplified diagram of the substation in abnormal configuration. The abnormal configuration resulted from closing of the second circuit breaker (CB1121/12) at the incident feeder after switching operations approximately 27 hours prior to the incident. This configuration effectively made the two substation bus bars in parallel. It is known that this abnormal configuration can create excessive “circulating current” within the station through the paralleling feeder (the incident feeder). This resulted in overstressing the electrical components between the two bus bars at the incident feeder, including the incident circuit breaker and its connections. The overstressed electrical connections above the incident breaker CB1121/22 eventually failed and resulted in an arc flash within the breaker cabinet.

[redacted]

Figure 9. Larkin simplified diagram – abnormal station configuration.

What follows is a description of the analysis method used in this investigation. It follows by the direct cause of the incident, including the cause of the substation abnormal configuration and barriers against discovery of such abnormality. Causal analysis and corrective actions related to the direct cause are outlined next, followed by the analysis of the emergency actions after the incident and restoration process.

Analysis Method

Approach

The approach used in this causal analysis is summarized here to provide context for the discussion and results presented in this report. The causal assessment team evaluated this event in accordance with a structured approach for causal analysis consisting of the following five (5) steps:

Data Collection

Data collection was performed through site inspections, review of event-related documents, digitally recorded data, recorded voice conversations, public records, and interviews. The collected data included the digitally recorded data at the time of the incident by the digital protection and SCADA system. Exponent was at the substation the night of the incident on April 21, during which time Exponent interviewed the available personnel, collected data, and photographically documented the substation condition. Exponent performed numerous site inspections in the months following the incident during which Exponent documented removal of the failed components and tagged them as evidence, inspected several protection and SCADA systems, and performed data collection for analysis of the existing systems as part of the direct cause analysis. Subsequently, Exponent interviewed 20 individuals that included PG&E personnel and a contractor as part of the direct cause and emergency action investigations. Exponent also collected the publically available information about the incident as part of this investigation.

Reconstruction of Problem Scenarios

As a result of the data collection activities, an event timeline was prepared to identify the relative time of events for use in evaluating the event. The detailed timeline included the emergency actions after the incident until the restoration was complete. The timeline was constructed using all available data, including: SCADA logs, fire alarm panel logs, audio recordings of DO calls, phone records, cell phone photographs following the incident, security camera footage, badge reader logs, station logbook, the fire department's Computer Aided Dispatch (CAD), and the fire department's radio recordings.

Performance of Causal Analysis

The causal analysis was performed in a structured sequence of steps that led to identification of the causes. The causal analysis tools used in this investigation were:

Events and Causal Factors Analysis (ECFA): This tool is used to identify potential systemic incident causes (i.e., management policies and organization) for each initiating event. It involves repeatedly asking why the event or pre-condition existed and provides evidence to support the *why* in order to identify the underlying causes. This tool was used for the primary causal analysis.

The outcome of the above causal analyses was the identification of the causes. This information formed the basis for developing recommended corrective actions.

Review for Extent of Condition and Extent of Cause

An outcome of the causal analysis was to identify the potential for the condition or cause to exist elsewhere.

Development of Recommended Actions to Prevent Recurrence

The desired outcome of the causal analysis was to identify recommended corrective actions to prevent recurrence of the problem and to identify lessons learned. Effective corrective actions are those that address the causes, are implementable by the organization, and are consistent with company business goals and strategies.

Data Collection

Documentation (Procedures and Project Records)

This analysis was performed through review of relevant documents, recorded data, publicly available information and interviews of PG&E personnel. The key documents reviewed in this analysis are listed in Table 1.

Table 1. Primary Documents Reviewed.

No.	Title	Topic
1	Switching log No 17-0035489	Switching log by the Golden Gate Control Center
2	Switching log No 17-0041875	Switching log by the Golden Gate Control Center
3	SCADA control logs on 4/20/17	Source file: "Concord DCC200 Alarm Log 42017 0500-0800.txt"
4	SCADA status logs on 4/20/17	Source file: "Martin100 04-20-17.log"
5	PG&E Utility Procedure TD-2700P-09	Responding to Emergencies and Alarms
6	PG&E Utility Procedure TD-2700P-16	Distribution SCADA Alarm Display Screens and Configurations
7	PG&E Utility Procedure TD-3320P-03	Fire Entry Procedure for an Indoor Substation
8	PG&E Drawing No 495433 Rev 3	12kV Network Feeder Y-1121, Elementary Diagram, Larkin Substation

No.	Title	Topic
9	PG&E Drawing No 472704 Rev 3	Cell 1-34, Diagram of Connections, Larkin Substation
10	PG&E Drawing No 435306 Rev 8	Elementary Diagram of 12kV Bus Differential, Network Transfer & Group Closing, Larkin substation.
11	SCADA log of Load Tap Changer (LTC) positions	Source file: "Larkin Bank LTC Positions.pdf"
12	Public records from the San Francisco Department of Emergency Management (SFDEM)	Event history details, FD recorded communications

Interviews

Exponent interviewed numerous PG&E personnel as part of the investigation. Key personnel interviewed during the course of the assessment are identified by title and role in Table 2 below.

Table 2. Key Personnel Interviewed.

	Title	Department
1	Electrician 1	Substation Maintenance
2	Electrician 2	Substation Maintenance
3	Electrical Inspector 1 (Contractor)	Canus Corporation
4	Cable Splicer	UG Electric Division
5	Cableman	Restoration
6	Troubleman / Rotational Supv.	Restoration
7	Division Operator 1	Distribution Operations
8	Division Operator 2	Distribution Operations
9	Electrician 3	Substation Construction (GC)
10	Apprentice Electrician 4	Substation Construction (GC)
11	Electrician 5	Substation Construction (GC)
12	Electrician 6	Substation Maintenance
13	Electrician 7	Substation Maintenance

Data Analysis

Analysis of Fault and Equipment Failure

The failure most likely originated near the top of the incident circuit breaker at the electrical connection points. This is based on the fire and arc flash analysis of the incident breaker cabinet. Additionally, the area on top of the breaker and at the switchgear bus bars running near the top of the cabinet show notably greater thermal damage as compared to other areas within the cabinet. There is also extensive arc damage on the top of the incident circuit breaker. Connections at the top of the circuit breaker in an exemplar breaker cabinet is shown in Figure 6. It should be noted that the PG&E personnel were able to manually trip the incident breaker during the restoration process using the trip button on the face of the breaker (Figure 10). This further shows that the breaker internal components were less damaged compared to the outside, suggesting that the area of the fault origin was outside of the circuit breaker.

Figure 10. PG&E personnel were able to manually trip the incident breaker during the restoration process; this shows that the incident breaker did not operate at the time of the incident.

The incident breaker (CB1121/22) did not operate, likely because the breaker cabinet was damaged due to the arc flash. It is unclear whether the fault would have been interrupted if the incident circuit breaker had operated. This is due to the extent of the damage near the top of the circuit breaker. The area of the fault origination near the top includes electrical connections at both the feeder side and the bus bar (source) side of the incident circuit breaker. The fault eventually included both sides of the incident breaker connections, at which time operation of the incident breaker could not have interrupted the fault. If the fault had been interrupted by operation of the incident circuit breaker, it would have been an exception to the general expectation of the outcome for such a severe fault inside the indoor substation. That is because the station protection system is designed to trip the entire substation in case of an internal fault of the indoor substation. This is a safety measure to ensure all Alternating Current (AC) power within the substation is de-energized when the emergency personnel respond to a fault inside the substation.

Protection System Operation

Review of the digitally recorded protection at the 115kV side of the station showed that the protection for transformer banks 1, 3, and 5 detected the fault and initiated the trip command within 8 cycles. The Y1121 feeder protection in the Larkin station is the older electromechanical type protection. Checking relay targets after the incident showed the instantaneous trip function operated. In addition, the CB1121/12 was found open after the incident. This suggests that the CB1121/12 operated after 8 cycles of fault current and interrupted the fault path from bus bar number 1. It also shows that the feeder protection operated as intended; however, the fault persisted. Review of the schematic one-line diagram (Figure 4) shows that the fault path from bus bar number 2 must have continued to feed to the fault location after 8 cycles. This means that, after 8 cycles, only transformer banks 2, 4, and 6 were supplying the fault current.

Digitally recorded data of the transformer high-side protections shows that transformer banks 2, 4 and 6 did continue to supply the fault current after the first 8 cycles. Banks 2 and 4 fault currents were eventually interrupted after 47 cycles and bank 6 fault current was interrupted after 49 cycles of 60 Hertz. This means that fault was eventually interrupted in approximately 0.8 second. The substation was dark after all six transformer banks lost power. Table 3 shows a summary of the substation bank protection operations. It was also discovered that contacts from the Bus Differential auxiliary tripping relays for both Y1121 circuit breakers were damaged[2]. These relays were located in the control room and away from the breaker cabinet. This did not have any impact on the outcome of the incident since the differential protection did not activate, likely because the fault location was outside the differential protection zone.

Table 3. Summary of selected protection data with recorded fault duration.

Bank No.	Device Name	Device Type	Device Function (Picked up)	Fault duration (cycles)	Trip Devices Include
BK1	87T-1	SEL-387E	50, 51	8	12kV ACBs Bks 1&2, CB172
BK1	150/151TA-1	SEL-501-2	X 51P, Y 51P	8	12kV ACBs Bks 1&2, CB172
BK1	151TB/51TT-1	SEL-501-2	X 51P	8	12kV ACBs Bks 1&2, CB172
BK2	87T-2	SEL-387E	51P1	47	12kV ACBs Bks 1&2, CB172

[2] Email from the PG&E test supervisor dated August 3, 2017

Bank No.	Device Name	Device Type	Device Function (Picked up)	Fault duration (cycles)	Trip Devices Include
BK2	150/151TA-2	SEL-501-2	X 51P, Y 51P	47	12kV ACBs Bks 1&2, CB172
BK2	151TB/51TT-2	SEL-501-2	X 51P	47	12kV ACBs Bks 1&2, CB172
BK3	87T-3	SEL-387E	50, 51	8	12kV ACBs Bks 3&4, CB172, CB182
BK3	150/151TA-3	SEL-501-2	X 51P, Y 51P	8	12kV ACBs Bks 3&4, CB172, CB182
BK3	151TB/51TT-3	SEL-501-2	X 51P	8	12kV ACBs Bks 3&4, CB172, CB182
BK4	87T-4	SEL-387E	51P1	47	12kV ACBs Bks 3&4, CB172, CB182
BK4	150/151TA-4	SEL-501-2	X 51P, Y 51P	47	12kV ACBs Bks 3&4, CB172, CB182
BK4	151TB/51TT-4	SEL-501-2	X 51P	47	12kV ACBs Bks 3&4, CB172, CB182
BK5	87T-5	SEL-387E	50, 51	8	12kV ACBs Bks 5&6, CB192
BK5	150/151TA-5	SEL-501-2	X 51P, Y 51P	8	12kV ACBs Bks 5&6, CB192
BK5	151TB/51TT-5	SEL-501-2	X 51P	8	12kV ACBs Bks 5&6, CB192
BK6	87T-6	SEL-387E	50, 51	49	12kV ACBs Bks 5&6, CB192
BK6	150/151TA-6	SEL-501-2	X 51P, Y 51P	49	12kV ACBs Bks 5&6, CB192
BK6	151TB/51TT-6	SEL-501-2	X 51P	49	12kV ACBs Bks 5&6, CB192

Load Tap Changer (LTC) Data

Recorded LTC positions by SCADA after the substation entered an abnormal configuration 27 hours prior to the incident shows increasing voltage deviation at the two parallel bus burs during that time period. The recorded data is shown in Figure 11. This data is interpolated for the missing time periods to provide a more accurate representation of the transformer bank tap positions. The interpolated data is shown in Figure 12. Increasing voltage deviation resulting from the increasing difference between the transformer tap positions translates in increasing circulating current at the incident feeder where the two substation bus bars are made in parallel during the abnormal configuration. The maximum tap position difference between the sets of transformers banks between bus bar No. 1 and bus bar No. 2 and the corresponding circulating current are calculated and plotted in Figure 13. It can be seen from this plot that the circulating current during the station abnormal configuration increased to approximately 1,800 Amperes before the incident occurred. This is beyond the maximum capacity of the incident transformer and its associated components (rated for maximum 1200 Amperes).

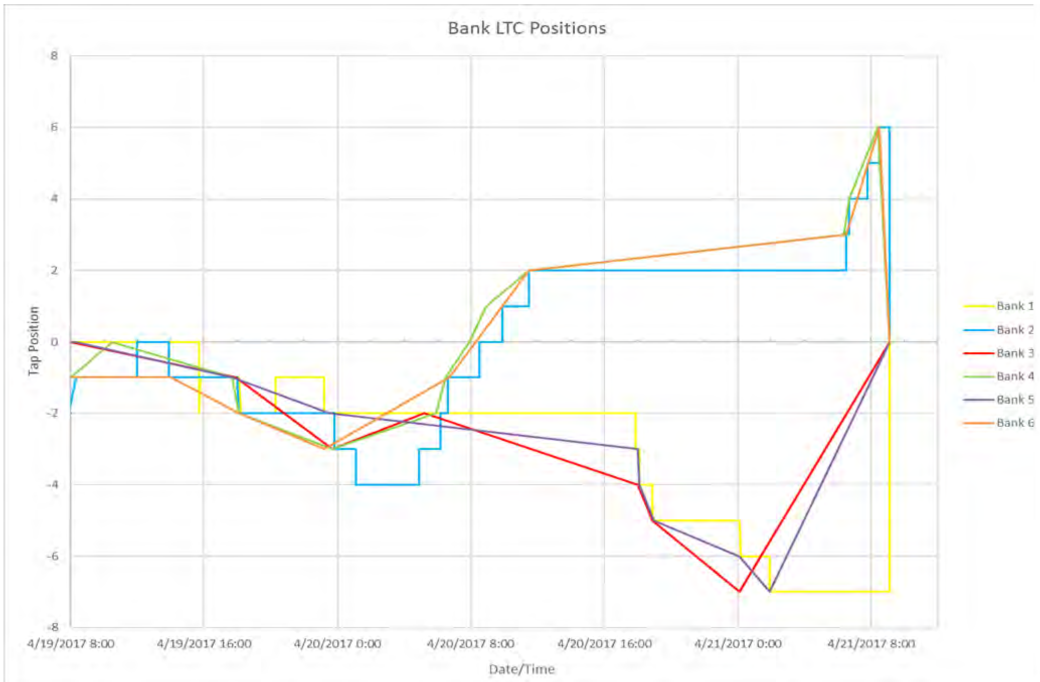


Figure 11. Recorded data of the transformer banks' LTC position.

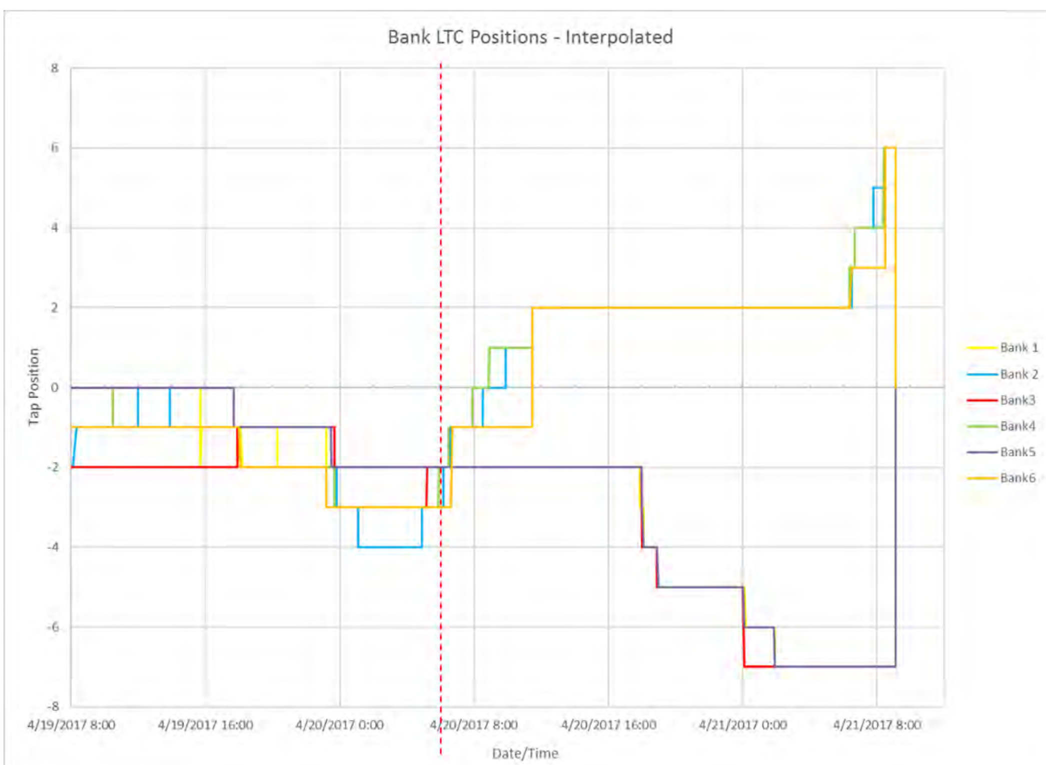


Figure 12. Interpolated data of the LTC positions.

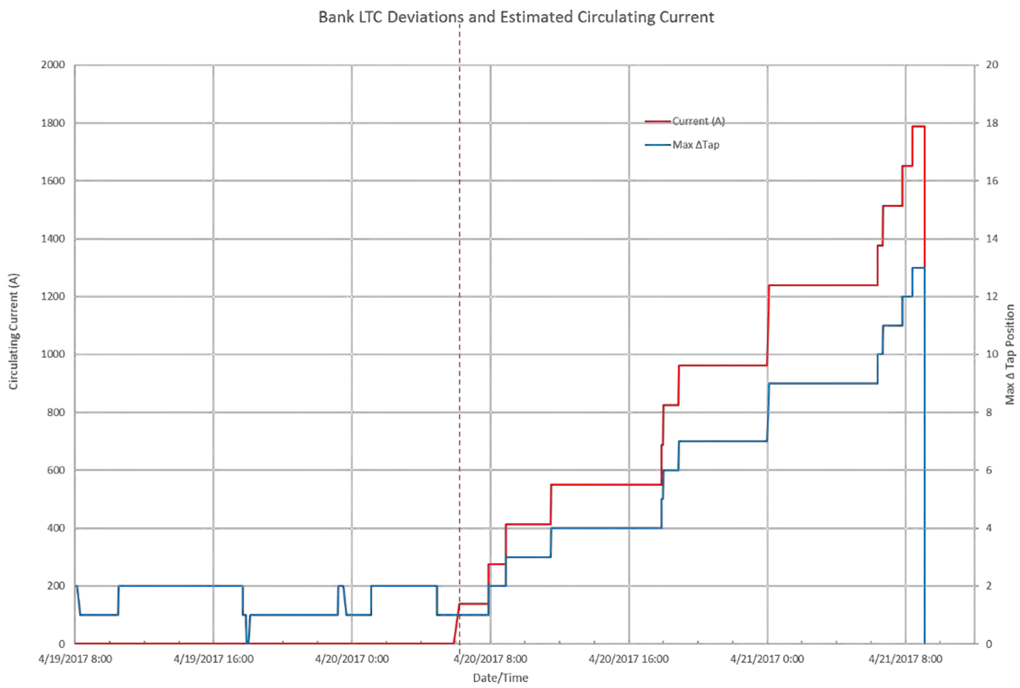


Figure 13. Maximum tap position difference and estimated circulating current.

Observations and Findings

Several findings are highlighted in the timeline in red. These findings are outlined next and are used as the starting points of the causal analysis.

The cause of the closing of the circuit breaker that resulted in the abnormal configuration of the substation prior to the incident is most likely a malfunction of the remote operating and control systems due to age and wear. The remotely operable control switch of the second circuit breaker was removed from service and examined in the laboratory (see Appendix A). The tests revealed that: (1) some of the switch characteristics have changed over time, likely due to aging; and (2) the switch is vulnerable to some system transients that could result in closing of the switch. The investigation team was able to rule out human influence causing inadvertent remote or manual closing of the second breaker as well as closing of the second breaker due to the designed automatic closing mechanisms.

Causal Analysis

Causal Analysis

The causal analysis was performed in a structured sequence of steps that led to identification of the causes. The causal analysis tool used in this investigation was the Events and Causal Factors Analysis (ECFA) tool which is used to identify potential systemic incident causes (i.e., process, policies and organization) for each initiating event. It involves repeatedly asking why the initiating event existed and providing evidence for each *"why"* in order to identify the underlying causes.

The causal diagram is provided in Figure 14. As appropriate, an explanation is provided that references the basis for the steps in the causal chart. The supporting material identified during the course of the investigations includes physical evidence, documents reviewed, calculations or testing, and interviews with PG&E personnel. These findings are summarized in Table 4 and Table 5.

Causes

This section provides the results of the causal analysis to identify the cause. Figure 14 provides the evaluation of the causes identified in the causal analysis chart to determine the causes of the incident.

The causal analysis has identified the following causes, including the following:

- Primary cause: Equipment malfunction due to age and wear. Based on the elimination of other possible causes of breaker closure, the malfunction of the remote operating and control system is the most likely cause of the CB 1121/12 closure and placing the circuit in a parallel bus configuration.

- Secondary cause: Human factors design of the SCADA monitoring and alarm system that did not provide for easy identification of the parallel bus configuration. For the Larkin substation, the breaker closure function is a Priority 9 alarm, and does not include an audible alarm. In addition, the visual cues for the breaker closure included an alarm list and a tabular configuration of the station. There was no graphical representation of the breakers status for the Larkin station. Additionally, the SCADA system in that station did not differentiate between a breaker "close" status and an out of operation or "racked out" breaker status due to the hardware design in Larkin station.

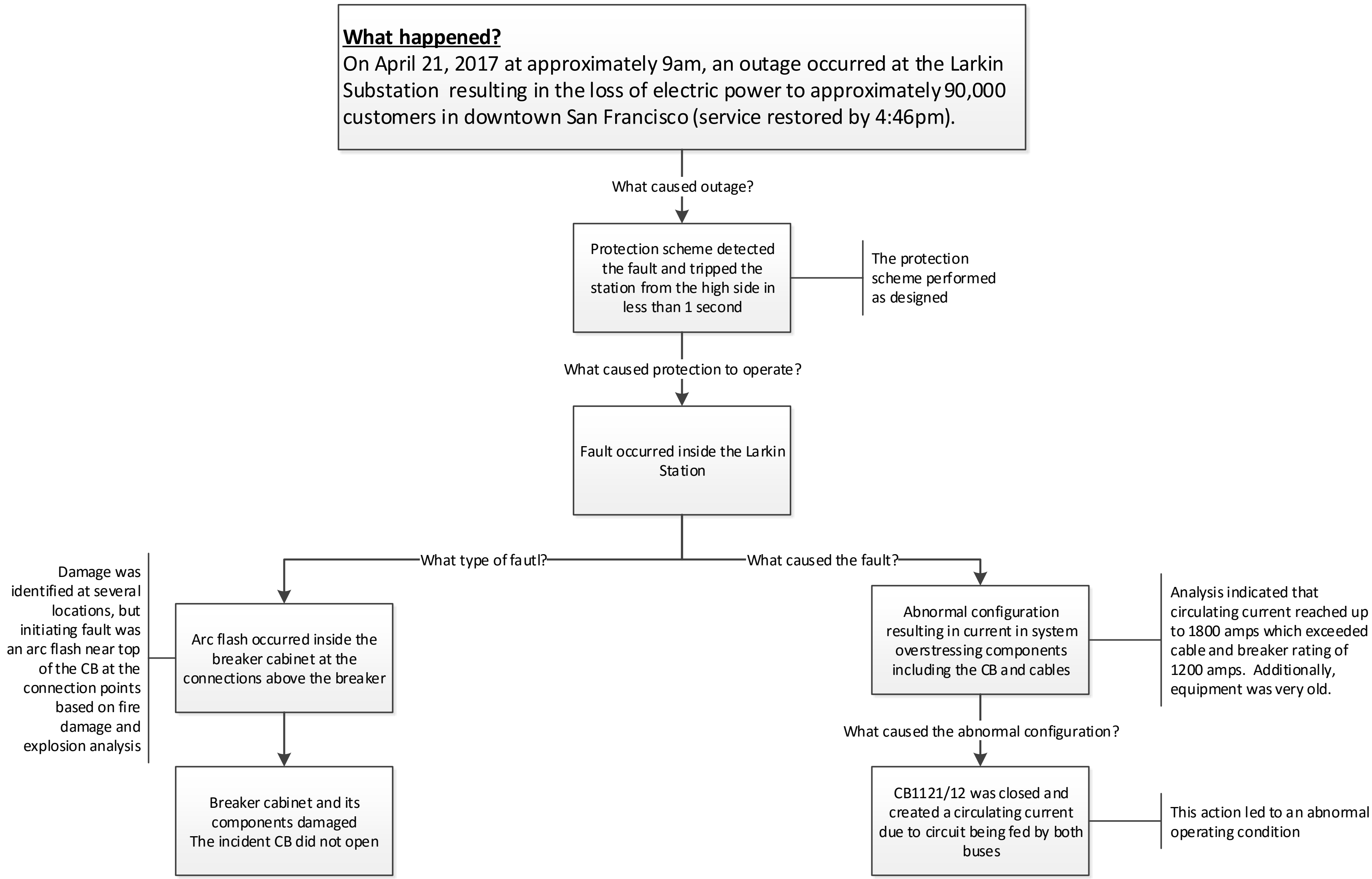


Figure 14. Causal Analysis Chart.

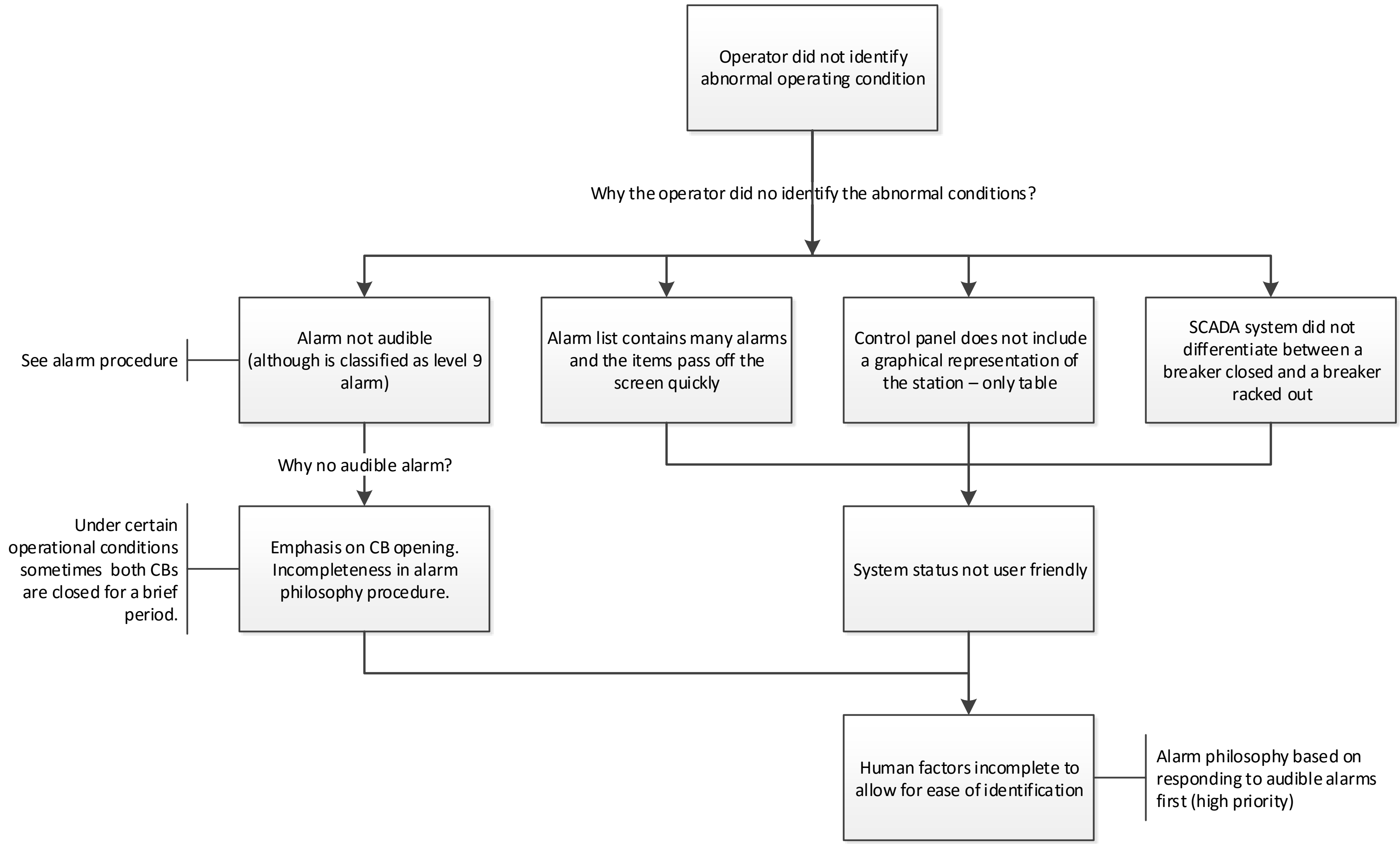


Figure 15. Causal Analysis Chart (continued).

Table 4. Summary of the supporting material for the identified potential causes.

Note	Initiating Event	Description	Evidence (Physical Evidence, Documents, Calculations or Testing)	Interviews	Other
SCADA Alarm not audible	Alarm philosophy: Emphasis on CB opening	SCADA alarm level 9 issued but missed by DO	Attachment 1 to TD-2700P-16: alarm summary table	Division Operators interview	
SCADA Alarm screen contains many low level and non-audible alarms	Incomplete human factor in the SCADA monitoring and alarm	DO missed the alarm on the screen		Division Operators interview	
Tabular reports of the breakers on the SCADA screen in control center	The breaker status was reported on the screen in tabular form rather than a more user-friendly graphical form	DO missed the CB1121/12 status after switching operations completed the day before the incident	SCADA screen shot	Division Operators interview	
SCADA system did not differentiate between the breaker closed and breaker racked out	In the Larkin station the breaker status was reported as “closed” if the breaker was racked out	Station SCADA wiring drawings and inspections	Elementary Diagram drawing No. 495433 Rev3 and Station Drawing No: 472704	Electrician and Division Operator interviews	
Equipment malfunction due to age and wear	The likely cause of the event was a malfunction of the remotely operable control switch for CB 1121/12. This switch is an older model switch has been in service for many years.	Based on elimination of other causes in the station other than condition of the existing switch and the remote operating system.	SCADA wiring inspections inside the station		

Table 5. Summary of the supporting material for the identified unlikely events.

Note	Initiating Event	Description	Evidence (Physical Evidence, Documents, Calculations or Testing)	Interviews	Other
Equipment malfunction due to the network automatic transfer mechanism and network group close mechanism	Network Auto transfer can potentially close a breaker in the event of loss of a station bus bar	Review of the transfer logic, inspection and testing of the existing system shows the malfunction in unlikely	Site inspections, PG&E test department report		Elementary No 495433 Rev3: 12kV Network Feeder Y-1121
Human influence causing inadvertent manual closing of the second breaker at the incident feeder	The station control switch can be used to close circuit breakers within the station	The Electricians performing the switching left the station 10 minutes before the SCADA-recorded closing of the CB1121/12 breaker	SCADA status log, station log book, security camera footage	Switching electricians interviews	
Human influence causing inadvertent remote closing of the second breaker at the incident feeder	The circuit breakers can be closed remotely via SCADA command	SCADA control log, which does not include a “control select” or “control execute” command prior to the recorded closing of the second breaker	SCADA control log	Division Operators interview	
SCADA wiring problem inside the station	Loose wiring and inadvertent contact with the positive DC source can potentially close a breaker	Review of the SCADA wiring inside the station did not show wiring abnormality	Site inspection and Photographic documentation of the SCADA wiring system		Elementary No 495433 Rev3: 12kV Network Feeder Y-1121
Circuit breaker CB1121/12 malfunction	Malfunction of the breaker’s internal circuitry could potentially close the breaker	The breaker operated at the time of the incident. It was placed back in service after the incident and tested	Digitally recorded fault data suggests that CB1121/12 operated within 8 cycles		Mechanical service record of CB#2 on 7/10/17

Corrective Actions

Recommended Corrective Actions to Prevent Recurrence

The desired outcome of a causal analysis is to identify corrective actions to prevent recurrence of the problem. Effective corrective actions are those that address the root cause, are implementable by the organization, and are consistent with the company goals and strategies. Based on the identified root causes, corrective actions recommended to address the causes of the event include the following. These corrective actions are also summarized in Table 6. It should be noted that there is an on-going project to upgrade and replace the switchgear in the Larkin Station that will address equipment age, wear and obsolescence issues.

1. Replace the remotely operable switch for the second circuit breaker (CB 1121/12) at the incident feeder inside the station (completed).

2. Develop an improved approach to identify and alarm the parallel bus configuration via feeder breakers, including

    a. Reevaluate the SCADA alarm categories, priorities of the alarms, and which alarms should be audible.

    b. Replace the existing tabular reports of the breakers status in the Larkin station with a graphical (single-line diagram) report for ease of identification (completed).

    c. Provide a separate detection and alarm system using SCADA for the closed feeder breakers causing a parallel bus bar in the Larkin station (in progress).

PG&E has reported plans for modifications in the SCADA system to immediately detect and report paralleled bus bars via feeder breakers inside Larkin station in the future. This action has already been taken by PG&E (graphical presentation and additional alarming system already implemented). The new Larkin switchgear is planned to be energized in 2018.

Table 6. Recommended Corrective Actions.

Cause	Recommended Corrective Action
Equipment malfunction due to age and wear.	Replace the remotely operable switch for the second circuit breaker (CB 1121/12) at the incident feeder inside the station. Evaluate the condition of the existing switch and the remote operating system. (Completed)
Human factors design of the SCADA monitoring and alarm system did not provide easy identification of the parallel bus configuration.	Develop an improved approach to identify and alarm the parallel bus configuration via feeder breakers. This may include: A. Reevaluate the SCADA alarm categories, priorities of the alarms, and which alarms should be audible.

Cause	Recommended Corrective Action
	B. Replace the existing tabular reports of the breakers status in the Larkin station with a graphical (single-line diagram) report for ease of identification. (Completed) C. Provide a separate detection and alarm system using SCADA for the closed feeder breakers causing a parallel bus bar in the Larkin station. (in progress)

Extent of Condition

PG&E has made improvements in the SCADA monitoring and alarm system to help with the human factors and ease of identification of similar abnormal conditions in the future. The improvements include replacing the tabular report of the breakers status in Larkin substation with a more user friendly graphical representation. The new graphical representation of the breakers status is in the form of the single-line diagram on the SCADA screen in the DO control center. Additionally, PG&E has developed a separate alarm system to create additional alarms in the case of abnormal parallel bus bars in Larkin station using the SCADA software and existing SCADA signal from Larkin station.

PG&E should review the other stations that utilize a similar switching and SCADA reporting scheme to determine whether the above recommendations are applicable to those facilities.

Analysis of the Emergency Actions

Station Overview

Larkin substation is an electrical substation distributing power to PG&E customers in San Francisco. The substation is located at 600 Larkin Street, on the corner of Larkin Street and Eddy Street. The station is adjacent to the Cova Hotel on Eddy Street. Figure 16 displays an overhead view of the city block containing the substation and the hotel. The Larkin Street and Eddy Street entrances are referred to throughout this report as the front and rear entrances, respectively.

[redacted]

Figure 16. Overhead view of Larkin substation and surrounding city block.

Timeline of Events Following the Incident

Immediate Response to Incident

At 9:06:06am on Friday April 21, 2017,[3] an electrical arc flash occurred at the Y1121 feeder at Larkin substation, resulting in a fire. The SCADA logs show a number of alarms within the same second, followed by more alarms 3 seconds later at 9:06:09am. According to interviews, three substation construction (GC) electricians (Electricians 3, 4, and 5), and one Canus Corporation contract inspector (Contract Inspector 1) were present inside the Larkin substation. Personnel inside the substation heard an explosion and began evacuation. At the time of the incident, Contract Inspector 1 reported in interview that he was seated at his desk approximately 30 feet from the incident breaker with his back to the arc flash. Electricians 3, 4, and 5 were in

[3] The incident time is established by the first recorded series of alarms in the SCADA logs.

the break room near the front entrance, and the cable splicer was outside the front entrance. A second Canus Corporation contract inspector (Contract Inspector 2) was located outside the back entrance. All personnel reported in interview that they heard an explosion, and Contract Inspector 1 saw the indirect light from the arc flash. Smoke and glow from flames were already visible as the electricians looked out from the break room door to call for Contract Inspector 1 to check that he was safe. Once Contract Inspector 1 reached the electricians in the break room, all personnel inside the substation proceeded to evacuate to the front entrance on Larkin Street.

The building fire alarm panel recorded the first general alarm due to a smoke detector activation in the basement 22 seconds after the incident, at 9:06:28am. The fire alarm panel recorded the second general alarm due to a smoke detector activation at the ground floor 33 seconds after the incident at 9:06:39 am. This second alarm was recorded in the SCADA logs. According to PG&E procedures, fire alarms are considered to be Priority 10 (highest level) and require an acknowledgement and immediate action by the system operator that includes calling 911 and dispatching personnel to the substation.[4] DO did not call 911 at any time during this incident which appears to be the result of a miscommunication between the DO and one of the personnel at the substation that left the impression that the SFFD was already notified.

The Larkin substation's fire alarms are maintained and operated by a third party fire alarm monitoring company. The normal procedure is that the activation of fire alarms would automatically notify this third party company, who would then call 911 to report the alarm to the fire department. The monitoring company reported that they did not receive automated notification of the fire alarm due to a missing update in the fire alarm panel's communication system firmware (see Appendix B). Therefore, the monitoring company did not call the fire department. The alarm panel's communication to the monitoring company was last tested successfully during an annual fire system inspection on June 11, 2016 (see Appendix C). This test simulated an alarm signal produced at the substation which was successfully detected and registered by the monitoring company. The problem with the communication system was identified and corrected after the incident.

After hearing the explosion and observing the fire and smoke from the incident breaker, the three substation construction electricians and Contract Inspector 1 evacuated through the front entrance by 9:07:51 am, 1 minute and 45 seconds after the incident. Electrician 3 called the substation construction supervisor (Supervisor 2) while exiting to inform him of the situation. Supervisor 2 instructed Electrician 3 not to let anyone in the building until the situation could be evaluated.

Distribution Operations (DO) made the first call reporting the loss of power at the Larkin substation at 9:07:54 am; approximately 1 minute and 48 seconds after the SCADA logs recorded the outage related alarms. DO called the Crew Lead Electrician, who dispatched a substation maintenance electrician (Electrician 6), located approximately 6.3 miles away at Daly City substation, to Larkin as the first responder. At 9:09:28 am, approximately 3 minutes and 22 seconds after the incident, DO made a call to the cable splicer at Larkin, who was preparing to work on the Y1124 feeder, and told him that the whole substation at Larkin was lost and asked him to stand down. During this call, DO was told that "the fire trucks are coming." At

4 PG&E Utility Procedure: TD-2700P-09 (Rev:0, dated 2014).

9:10:06am, around 4 minutes after the incident, DO was informed by the Crew Lead Electrician that Electrician 6 was on his way to Larkin. This means the dispatch of Electrician 6 occurred at approximately 9:09am, around 36 minutes before Electrician 6 would eventually arrive at Larkin substation as the first responder.

Approximately 14 minutes after the incident, at 9:20:10am, Electrician 3 called DO and informed them that all personnel were evacuated safely, that they could not get back in the station, and that something was burning inside. DO informed Electrician 3 that an electrician (Electrician 6) was en route to Larkin.

At 9:16 am, approximately 10 minutes after the incident, Apprentice Electrician 4, located outside the front door of Larkin substation, called 911 three times from his cell phone but he was placed on hold. The last call lasted up to 7 minutes. At 9:23 am, approximately 17 minutes after the incident, Apprentice Electrician 4 called the main line of the San Francisco Fire Department and reported the fire incident. A member of the Fire Prevention department then called Fire Dispatch and relayed the message regarding the Larkin incident. The fire department initiated its incident response at 9:28:19am,[5] approximately 22 minutes after the incident, and the first engine was reported on scene at 9:31:59am, approximately 3 minutes and 40 seconds after the incident response was initiated by the fire department, and approximately 26 minutes after the incident itself.

Delay in Notification of the Fire Department

The 22 minute delay in notification of the fire department can be attributed to the confluence of three independent circumstances:

1. The third party fire alarm monitoring company did not receive an automated notification of the fire due to an error in the fire alarm panel's communication system and thus did not call the fire department.
2. DO did not call 911 upon receiving the fire alarm.
3. The substation electrician standing outside of the substation did not get through to the 911 operator; they ultimately called the front desk equivalent of the San Francisco Fire Department, who conveyed the message to dispatch.

After Fire Department Arrival

Approximately coincident with the arrival of the first-in fire engine at 9:32am, a restoration cableman (the cableman) arrived at Larkin in response to the outage alert on the outage management tool (OMT/OIS). Shortly after the arrival of the cableman, a substation maintenance electrician (Electrician 7) arrived. The cableman approached firefighters and the substation personnel gathered near the front entrance of the building and was informed by Electrician 3 that no one was allowed to enter per instructions of Supervisor 2 who was at that time still en route to Larkin. This was disputed by the cableman, who stated that the fire department needed to enter the building immediately. The cableman spoke by phone with

5 According to San Francisco Fire Department Computer-Aided Dispatch (CAD) logs.

Supervisor 2, and after some disagreement, the cableman stated to those present that he was now the IC. The cableman attempted access through the front door of the substation, but the badge reader was not functioning and the required physical keys were not present. At this time, a responding restoration troubleman (rotational supervisor, the troubleman) arrived and both the cableman and the troubleman moved to the rear of the building to continue to attempt access to the interior of the building.

According to fire department radio logs, by approximately 9:33:00am, 27 minutes after the incident, the first-in fire engine (E03) positioned at the front of the building conveyed to fire dispatch that the substation crew had left the building after hearing an explosion, that no one was injured, and that they were waiting for a supervisor to let them in as the station was locked. Additionally, E03 described a "light smell" consistent with an electrical fire. At 9:35:00 am, E03 reported no visible smoke. Approximately 20 seconds later, at 9:35:20am, the first-in truck (T03), arriving at the back of the building, reported "a decent amount of white smoke" coming off the top of the building. By 9:35:40am, less than 4 minutes after the fire department first arrived on-scene, fire department radio communications indicate that PG&E personnel had informed the fire department that "the power is out in the whole building".

At some time after the fire department arrived on scene and before the cableman and troubleman moved around to the back of the building, Electrician 3, at the request of Supervisor 2, instructed the fire department not to enter the building because it was not known to be safe.

By approximately 9:37:00am, 5 minutes after first arriving on scene, firefighters at the rear of the building communicated on radio that there was someone present who had keys and that they could make entry at any time. They were again told by other firefighters responding on the radio to wait for the PG&E supervisor. Around 9:37:40am, 5 minutes and 41 seconds after first arriving on scene, firefighters at the rear of the building again radioed, saying that someone filling in for the supervisor wanted to make an immediate entry. They were again asked to wait by other fire department personnel. Around 9:38am, approximately 6 minutes after the fire department first arrived on scene, Contract Inspector 1 used his badge to open the rear stair door.[6] He reported in interview that he propped the door open and left another PG&E employee to watch the door while he went to secure the gate access to the rear of the building. Around the same time, a firefighter radioed that PG&E employees wanted to enter and that he was telling them to hold off from entering. Around 9:39:20am, approximately 7 minutes after first arriving on scene, fire department personnel from T03 radioed that the rear door was open and that the highest ranking PG&E employee was with them. Around 9:43:20am, more than 11 minutes after the fire department first arrived on scene, a firefighter radioed that they were still outside looking in the back door, and that while the building was de-energized, there was some battery power still inside. Another fire department person responded that they were still waiting and trying to make an entry in the front of the building.

At 9:43:29 am, approximately 37 minutes after the incident and 11 minutes and 30 seconds after the fire department first arrived on the scene, DO told a responding substation maintenance electrician (Electrician 7) to tell the fire department that the whole station was de-energized from the sources, and so when they can get in, they can extinguish the fire. DO then instructed

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6 Recorded in badge ID reader logs, multiple attempts between 9:38 am and 9:39 am.

Electrician 7 that an employee with a respirator must accompany the fire department into the station as the fire department did not know their way around the station. PG&E procedures prevent PG&E personnel from entering a burning, or potentially burning, substation. The fire plans, in conjunction with advice from the IC, are designed to assist with fire department situational awareness inside the substation.[7]

Sometime after 9:38 am and before 9:46 am, the cableman, the troubleman, and two other PG&E employees entered the Larkin substation to assess the fire. Smoke was reportedly present at this time. PG&E procedure prohibits entry into a structure by non-emergency personnel when smoke is present. The troubleman reported in interview that he walked through the station to confirm that only the incident breaker was involved in the fire, and then came back out of the rear door to inform the fire department that only one cell was involved. Meanwhile, the cableman went through the inside of the building towards the front door. The cableman reported in interview that he was present inside the front door when the fire department entered, after forcing open the front door at approximately 9:46 am.

Shortly before the fire department forced open the front door, Electrician 6, who was sent to Larkin by the Crew Lead Electrician as a first responder at approximately 9:09 am, arrived and assumed the IC role, about 39 minutes after the incident and 36 minutes after initially being dispatched. Electrician 6 instructed the fire department, at the request of the substation maintenance supervisor (Supervisor 1) on the phone, to retrieve the fire pre-plans and the station logbook from inside the front door. The fire department forced open the front door immediately after this instruction.

Also at approximately this time, the only recorded 911 call was made by a guest at the neighboring Cova Hotel at 9:44 am, 38 minutes after the incident and after the fire department had already been on the scene for almost 12 minutes. The caller reported hearing an explosion approximately 25 minutes earlier and stayed on the line with the dispatcher until seeing a firefighter climb onto the roof, at which point the dispatcher informed the caller that the fire department was on scene and already aware of the incident.

Fire Department Entry to the Substation

The fire department entered the building from the front and rear of the station at approximately 9:46 am, based on radio logs and the time when the fire alarm was recorded as silenced from inside the building at 9:46:38 am on the fire panel logs. This represents a total elapsed time of 14 minutes from the arrival of the fire department at about 9:32 am to entering the building to fight the fire. The elapsed time from the incident at 9:06:06 am to the fire department entering the building was approximately 40 minutes.

Exponent understands that the fire department requires some time to assess the situation and prepare equipment before entering any burning structure. The fire department radioed that entry was possible at any time by 9:38am, approximately 6 minutes after arrival, when Contract Inspector 1 opened the rear door with his badge. Further, the fire department radioed that they had been informed that the power was out less than 4 minutes after arriving on scene. This

[7] PG&E Utility Procedure: TD-3320P-03 (Rev:0, dated 2014).

suggests that, had an IC been established and in contact with DO within 4 minutes of the fire department's arrival, the fire department could have started working to force open the door at that time, roughly 10 minutes before they were eventually able to do so (from FD arrival at 9:32 am to actual entry at 9:46 am).

Additionally, accounting for the quick arrival time of the fire department after notification, had the 22-minute period between the incident and the fire department's incident response initiation been a nominal 2 minutes, it is possible the fire department could have arrived on scene as early as early as 9:12 am, within 6 minutes of the incident. Based on the actions of the fire department and PG&E personnel present at this time, it is possible that the fire department would have still waited for a first responder to arrive, which could mean that they would still not have entered until after Electrician 6 arrived, roughly 40 minutes after the incident. The electricians present on site were directed by the supervisor not to enter or to allow anyone else to enter, the substation until the situation was understood. If PG&E first responders had access to emergency vehicles or emergency escorts such that their response time was similar to that of the fire department, the expected time of entry by the fire department in this particular case could be reduced by approximately 10 minutes.

After Fire Department Entry

The fire department entered the back and the front of the building around the same time, shortly after the arrival of Electrician 6, the designated first responder. Around 9:46 am, approximately 14 minutes after first arriving on scene, the fire department opened the large roll-up door at the back and reported a visual on a trash-can size fire after stepping in the doorway about 20 feet. Around the same time, other firefighters made entry through the front main door. The cableman reports that he was inside the front door at this time and other Electricians report the cableman exited the front door shortly after the fire department forced it open. The cableman was reportedly wearing "normal PPE". At 9:46:38 am, approximately 38 seconds after the fire department reported making an entry through the front main door, the silence button was activated on the fire panel which is located near the front door. Around 9:49 am, approximately 17 minutes after first arriving on scene, the fire department dispatch noted that the inside was being checked and everything seemed clear. It is likely that this does not indicate the absence of smoke, which was reported to be present down to approximately 10 feet or less above the ground inside the station by the troubleman and cableman.

Supervisor 1 arrived at Larkin at roughly 9:50 am and assumed the IC role from Electrician 6 once the fire department had secured the fire pre plans.

By 9:51 am, approximately 45 minutes after the incident and approximately 19 minutes after the fire department first arrived on scene, a firefighter radioed that they were comfortable venting the station, and, from what they could see, there was a very small fire, that they thought that they should be able to get it under control with a few dry chemical fire extinguishers, and that they thought that they should go ahead and do so. Approximately 40 seconds later, at 9:51:40 am, another firefighter asked if attempts to extinguish the fire had begun because they saw that smoke coming out of the roof was becoming darker. This darkening smoke was reported in the media as a sign that the fire was worsening.[8]

At 9:53 am, photographs were taken inside the substation on the troubleman's cell phone showing flames inside the Y1121 cabinet. At 9:54 am, another cell phone photograph taken shows firefighters fighting the fire with hand-held fire extinguishers. At the same time, almost 48 minutes after the incident and 22 minutes after the fire department first arrived on scene, a firefighter radioed that they were now actively attempting to extinguish the fire. By 9:57 am, approximately 25 minutes after first arriving on scene, firefighters radioed that they may want the CO_2 unit responding because they were able to knock the fire down, but the fire seemed to be coming back.

By 10:01:01 am, approximately 29 minutes after first arriving on scene and approximately 4 minutes after getting the request from the firefighters at Larkin for the CO_2 unit, the fire department dispatch sent a command to Engine 4 (E04) to retrieve the CO_2 unit from station 13. At 10:12:00 am, approximately 15 minutes after getting the request from the firefighters at Larkin for the CO_2 unit, the fire department dispatch sent another command to E04 to retrieve the CO_2 unit from station 13. The CO_2 unit was listed in the SFFD CAD logs as being en route at 10:32:35 am, 35 minutes after the request for the CO_2 unit.

At 11:17:35 am, approximately 2 hours and 11 minutes after the incident and approximately 1 hour and 45 minutes after the fire department first arrived on scene, Supervisor 1 informed DO that the fire was extinguished and that ventilation was underway, and due to the presence of smoke, PG&E employees were not yet admitted to enter the building. Another communication with the DO indicates that entry was still not allowed for PG&E employees at 11:47:27 am, 2 hours and 41 minutes after the incident and 2 hours and 15 minutes after the fire department first arrived on scene. Sometime between 11:47:27 am and 12:12 pm, PG&E employees entered Larkin substation.

After PG&E Entry

According to the Substation Maintenance Superintendent (Superintendent), at approximately 12:12 pm, 3 hours and 6 minutes after the incident and 2 hours and 40 minutes after the fire department first arrived on scene, the Superintendent, Supervisor 1, and a few other PG&E personnel entered Larkin substation with the fire department after the fire department deemed the space safe for reentry. The Superintendent led the effort to restore station service. Service was restored from the 1104 source at 12:15 pm, and the restoration process was initiated.

Around 2:30pm, all bank breakers and tie breakers were checked, banks 2, 4, and 6 were isolated, and banks 1 and 5 were energized. Bank 3 would not energize due to a problem with its low side breaker. Between 2:38 pm and 2:56 pm, the 115 kV bus was returned to normal operation, and Bus 1 sections D, E, and F were energized, restoring customers.

[8] NBC News report.

At approximately 3:10 pm, smoke was reported again and the Y3 network was dropped for further investigation. By 4:25 pm, the bank 3 low side breaker was swapped out, switches were opened in the field to isolate back feed on Y3, and the Y3 network was tested and reenergized.

All customers were restored by 4:46 pm, 7 hours and 40 minutes after the incident, and 4 hours and 34 minutes after PG&E employees were first allowed back in to the station by the fire department.

Evaluation of Steps Taken by Involved Parties

Evaluation of the response to the incident by PG&E was complex, involving many steps taken by many individuals and groups. Exponent has separated the critical parts of the response into the Emergency Notification phase, and the response by Substation Personnel, DO, Underground and the Fire Department.

Emergency Notification

The immediate response by PG&E to the incident is summarized in Figure 17. In this schematic representation of the emergency notification process, the fault causes an explosion and fire in the substation. The fault itself is detected by SCADA, notifying DO of power loss immediately. The explosion, fire, and smoke produced by the fault alert the electricians on site, who evacuate to the front of the building and notify Supervisor 1. The smoke from the fire sets off several fire alarms over the seconds and minutes following the incident, which are also logged by SCADA and alert DO. The fire alarms should also have notified the third party fire alarm monitoring company but in this instance, no alarm was sent due to an equipment malfunction, and thus the third party monitoring company did not call 911. The fire alarms were detected by SCADA and sent to DO; however, DO also did not call 911.

After waiting approximately 10 minutes with no sign of the fire department, Electrician 4 called 911 several times from his cell phone but was placed on hold. About 17 minutes after the incident, Electrician 4 found the number for the fire department's main office and called directly to report the fire. This message was relayed to dispatch and the fire department began its incident response at 9:28:19 am. The fire department arrived less than 4 minutes later, reporting Engine 03 on scene at 9:31:59 am, about 26 minutes after the incident.

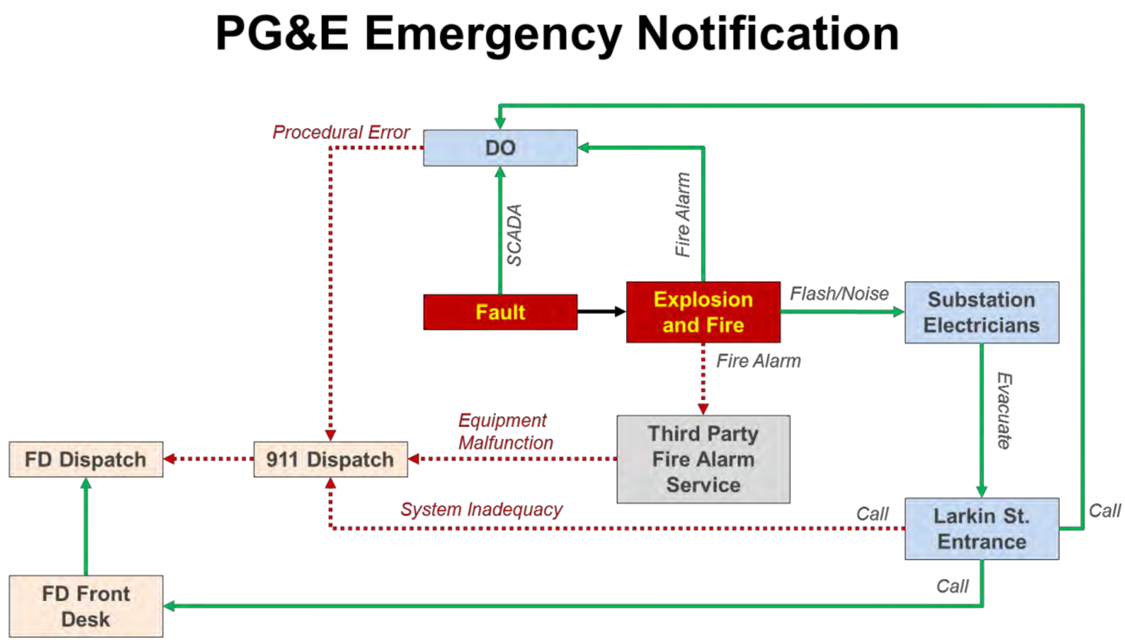


Figure 17. Flow Chart of Emergency Notification Process by PG&E following fault and explosion at Larkin substation. 911 is not reached due to three separate issues. Station electricians eventually called the fire department's main office directly to report the fire.

Evaluation of Steps Taken by DO

DO plays a key role in the incident response. DO is responsible for calling 911 to notify the fire department of fire alarms at a substation. DO coordinates with dispatch to assign a first responder who will serve as Incident Commander to communicate effectively with the fire department. DO must remain in contact with the Incident Commander in order to inform them of the status of the high voltage sources feeding the substation. When the substation is electrically clear, the Incident Commander can assist the fire department with safe entry to fight the fire.

The actions taken by DO following the incident and up to the fire department entering the building at Larkin are illustrated in Figure 18. DO received the fire alarm via SCADA and contacted dispatch to send a first responder to Larkin, but did not call 911. The first responder was Electrician 6 at Daly City substation, although three electricians were present at Larkin at the time of the incident. DO did not establish a clear communication link with the Incident Commander. Electrician 7 was told that the equipment was clear and the fire department could enter to fight the fire at 9:43:29 am, approximately 37 minutes after the incident. Electrician 7 was not the acting Incident Commander at any time during the response, rather, Electrician 6 arrived around this time and assumed Incident Command. DO told Electrician 7 that a PG&E employee would need to enter the building with the fire department with a respirator to help the fire department navigate the substation. The procedure TD-3320P-03 warns that no non-emergency personnel should enter the substation if smoke is present.

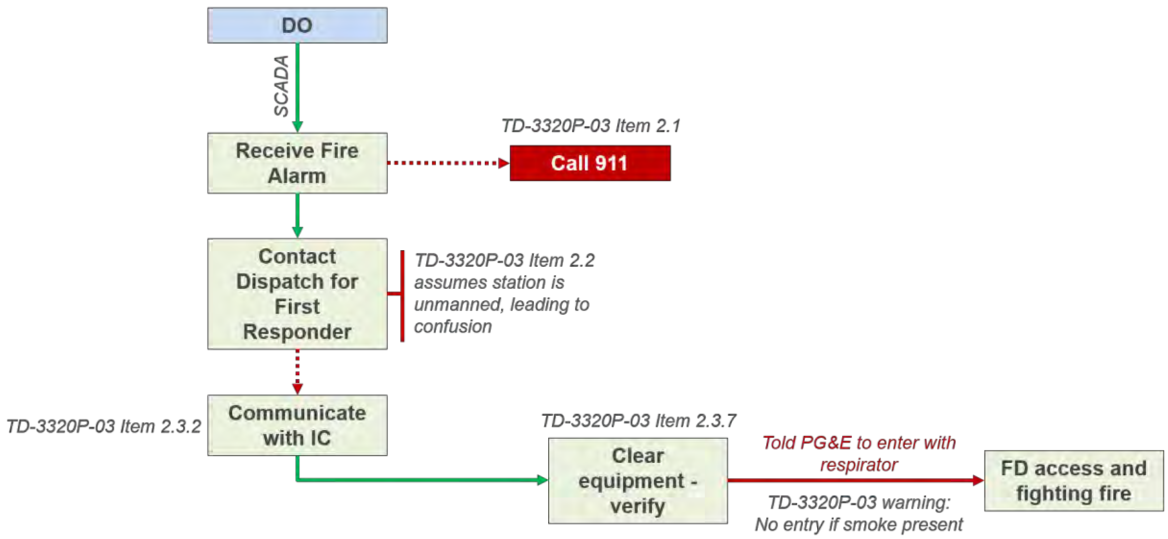


Figure 18. Response and actions taken by DO in response to the incident at Larkin Substation.

Evaluation of Steps Taken by Substation Personnel

Electricians 3, 4, and 5, the cable splicer, and Contract Inspector 1, and possibly other personnel, were on site when the incident occurred, putting them in a unique position for PG&E emergency response. The procedures are written such that they assume the substation will be unmanned at the time of the incident and an electrician will have to be dispatched to the site. Therefore, there is a comparatively small role in the overall response for persons present at the site.

The actions taken by employees and contractors present at the site are illustrated in Figure 19. Electricians 3, 4, and 5 were in the break room, the cable splicer was outside, and Contract Inspector 1 was in the switching area, approximately 30 feet from the incident breaker when the incident occurred. Responding to the noise and signs of a fire, all personnel evacuated to the front entrance on Larkin Street. At this point, no employee clearly took the role of Incident Commander. Electrician 3 was in contact with Supervisor 2 and was considered to be in command by several personnel present, based on interview responses. DO received a call from Electrician 3 describing the loss of power and fire. DO verified with the cable splicer that all personnel were safely outside the substation. After approximately a 10-minute wait without seeing the fire department, Apprentice Electrician 4 called 911 unsuccessfully, and eventually reached the fire department's main office on his cell phone at approximately 9:23 am.

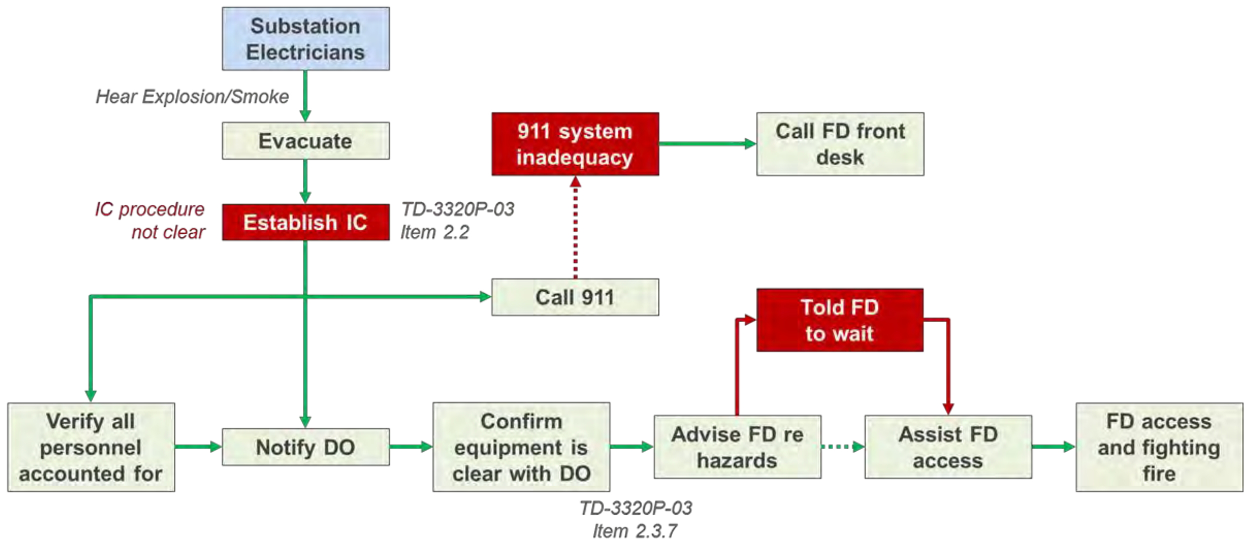


Figure 19. Response and actions taken by restorations personnel on site at Larkin substation.

Around the time that the fire department arrived at approximately 9:32 am, the cableman arrived and, after being told not to enter the building by Supervisor 2 on the phone, assumed Incident Command. The cableman did not follow the procedure for the Incident Commander however, and proceeded to gain access to the building through the rear door and enter the substation prior to the fire department entering to assess the situation. The Incident Commander is required to communicate with DO to determine the status of the high voltage sources feeding the station and communicate with the fire department when it is safe to enter. The Incident Commander is also required to prevent non-emergency personnel from entering a burning or potentially burning substation. The actions of the cableman and other restoration personnel upon arriving at the substation are illustrated in Figure 20.

The cableman and the troubleman entered a burning substation. While this was happening, Electrician 6 arrived at Larkin and assumed the Incident Commander role as the first responder. Electrician 6 requested the fire department to force open the front door and retrieve the fire pre-plans from inside the substation. DO was in communication with Electrician 7 on the phone and explained that the station was dark. DO instructed Electrician 7 that someone with a respirator should enter the building with the fire department.

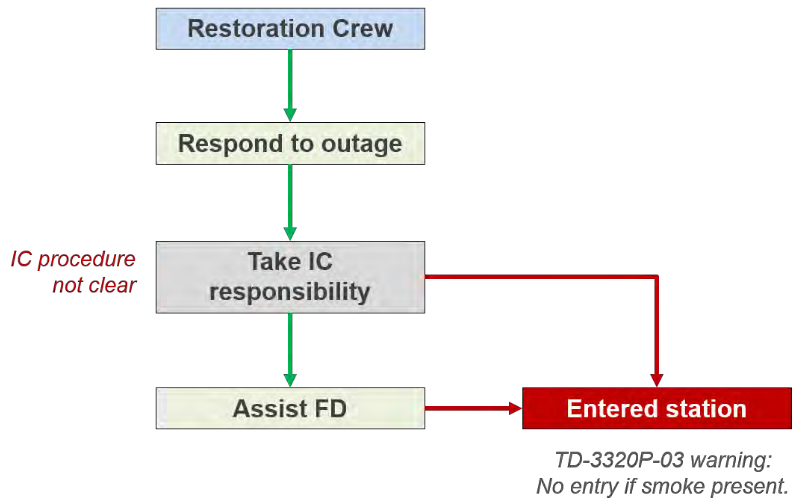


Figure 20. Response and actions taken by restoration personnel responding to the incident at Larkin Substation.

Lessons Learned and Recommendations

The following lessons can be learned from the detailed review of the actions performed by PG&E personnel and the fire department:

The fire started at 09.06 am. The factors influencing the response are:

1. The fire department did not receive an emergency notification until approximately 22 minutes after the incident due to the DO not calling 911 upon receipt of the fire alarm, unavailability of the 911 system preventing substation personnel from contacting 911 dispatch directly, and a failure of the automatic third party fire alarm notification system.

2. The fire department entered the building at 9:46 am, approximately 14 minutes after their arrival. Around the same time, Electrician 6 arrived as the PG&E first responder and asked the fire department to retrieve the fire pre-plans from inside. Electrician 6 was dispatched to Larkin at approximately 9:09 am, but did not arrive until shortly before the fire department made entry at around 9:46 am.

These are opportunities to improve emergency response effectiveness, and Exponent recommends the following:

1. It appears that the protocol for the assumption of the PG&E IC role, as outlined in TD-3320P-03, section 2.2, was not clearly understood by PG&E personnel assuming incident command role. As a result, multiple PG&E personnel assumed the role of IC concurrently. Additionally, the cableman responding to the incident assumed the IC role, but did not communicate with DO and entered the burning substation along with other restoration personnel. The IC role includes communication with DO and prevention of PG&E employees entering a burning, or potentially burning, substation.

2. The TD-3320P-03 procedure assumed certain scenarios and did not address others. Specifically, the procedure assumes that the station would be unmanned at the time of the incident and that the first responder would have to be dispatched. This was not the case during this incident as personnel were already present on the scene who could potentially have served as first responder. Additionally, the procedure's title "Fire Entry Procedure for an Indoor Substation" may be misleading as the procedure is meant to establish protocols to *prevent* PG&E personnel from entering a burning, or potentially burning, substation. PG&E may consider expanding the procedure to include situations where qualified personnel could be already present at the site.

3. Certain established PG&E procedures were not adhered to by PG&E personnel. For instance, fire alarms require an acknowledgement and immediate action by the system operator that includes calling 911 and dispatching personnel to the substation. DO did not call 911 at any time during this incident. Additionally, PG&E employees entered a burning substation, but the procedure TD-3320P-03, section 2.3.4, requires the first responder (acting IC) to prevent all non-emergency personnel from entering a burning, or potentially burning, substation. Exponent recommends that PG&E consider performing a review of the effectiveness of the emergency response training provided to the PG&E employees.

4. The third party fire alarm monitoring company did not receive automated notification of the fire alarm due to an error in the fire alarm panel's communication system, and hence the monitoring company did not call the fire department. The alarm panel communication to the monitoring company was last tested successfully during an annual fire system inspection on June 11, 2016. The problem with the communication system was identified after the incident. Exponent recommends that PG&E consider random audits of the fire alarm panel's operation.

5. The PG&E IC is required to discuss the fire pre-plans with the fire department and to advise them of hazards, and communicate information regarding equipment clearances. This role is critical to ensuring timely access to the fire by the fire department. Exponent understands that the fire department and PG&E employees conduct routine training exercises to prepare for a substation fire during which the protocols are practiced. However, some of the PG&E personnel at the site did not appear to have a clear understanding of their roles and the procedures at the time of the incident. Exponent recommends that PG&E consider a review of the joint training exercises such that the roles and responsibilities of the PG&E employees and the fire department are clearly delineated and understood.

6. The fire department did not initially dispatch the CO_2 unit that PG&E had purchased for the fire department specifically to assist with fighting electrical equipment fires. The CO_2 unit was dispatched approximately 30 minutes after the fire department first arrived on scene. Exponent recommends that PG&E consider working with the fire department to establish the practice of immediately mobilizing the CO_2 unit in the case of substation and switchgear fires, whether indoor or outdoor.

7. Based on the present procedure, in the case of a substation fire, the fire department could potentially wait for a significant amount of time while a PG&E first responder is dispatched and arrives at the substation. Exponent sees an opportunity for PG&E to work with the fire

department and other city emergency services to consider the procurement of emergency response vehicles and/or to establish effective emergency escort procedures to improve response time by first responders so that an IC can be established quickly.

References

Main references include:

1. Utility standard TD-2700-16, *Distribution SCADA Alarm Display Screens and Configurations*, Rev0, 10/21/14
2. Utility standard TD-2700-16, *Responding to Emergency and Alarms*, Rev0, 10/29/14
3. Attachment 1 to TD-2700P-16, *Alarm Summary Table*
4. Utility standard TD-3320P-03, *Fire Entry Procedure for an Indoor Substation*, Rev0, 12/31/14
5. Elementary Diagram drawing No. 495433, *12 kV Y3 Network Feeder*, Rev3, 6/15/08
6. Elementary Diagram drawing No. 435306, *12kV Bus differential, Network Transfer & Group Closing*, Rev8, 9/7/05
7. Diagram of Connections No. 472704, *Cell 1-34*, Rev3, 7/19/91
8. Electroswitch Technical publication CSR-1, *Electrically Operated Control Switch Relay for both manual and supervisory control of power circuit breakers*, Effective January 1997
9. Circuit-Breaker Maintenance form, Metalclad Circuit Breaker Mechanism Service, 9/20/16
10. Circuit Breaker Maintenance Form, Functional-Performance Test, 9/20/16
11. Substation Infrared Inspection, 7/11/16
12. Fire Alarm Data Log, PGE SF Sub Y Larkin History, 4/21/17
13. SCADA status log, and control log on 4/21/17
14. Station log book, logged data on 4/21/17
15. Security camera footage in Larkin station on 4/20/17
16. Larkin protection event files on 4/21/17
17. Golden Gate Control Center Switching Log No. 17-0035489, 4/20/17

Appendix A

Breaker Control Switch Testing

Appendix A: Breaker Control Switch Testing

Introduction

The control switch for the Y1121/12 breaker, thereafter referred to as the incident switch, was removed from the Larkin substation on August 5, 2017 and received by Exponent for laboratory testing. Exponent also received two exemplar switches of the same type and model for testing and comparison.

The incident switch is an electromechanical switch manufactured by Electroswitch Corp (Electroswitch). Figure 1 shows a photograph of the incident switch after removal from the control panel in the substation. The switch model is CSR 24, 48 VDC and the manufacturer catalogue number is 8847CB-001. Figure 2 shows the markings on the incident switch indicating its type and model.

The incident switch was installed with three external components attached to its terminals. Two 600V fast recovery diodes were attached between the ground (TB4) and the Trip (TB1) and the Close (TB2) terminals of the switch. A 200V Transient Voltage Surge Suppressor diode (Transil Diode) was attached between the Trip (TB1) and Close (TB2) terminals of the switch. These components were still attached to the incident switch terminals when received by Exponent and are shown in Figure 3.

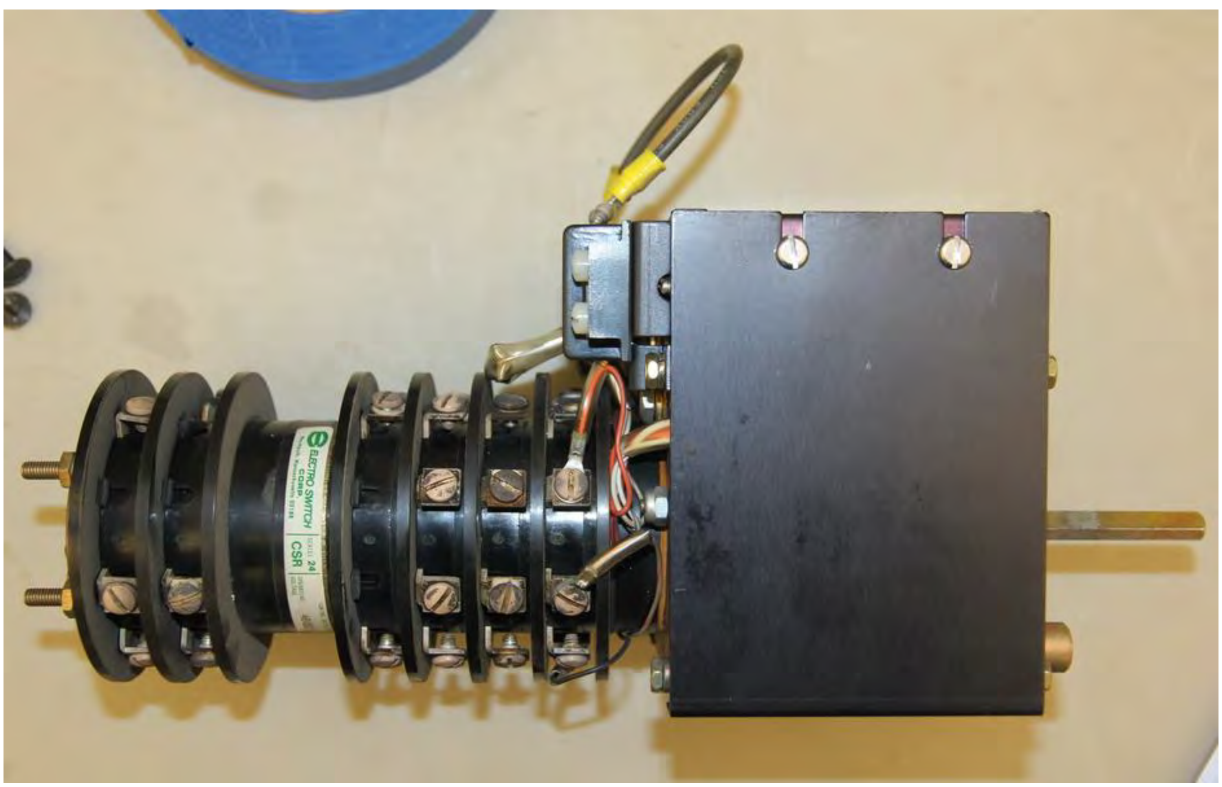


Figure 1. The incident switch removed from the control room in Larkin substation.

Figure 2. Incident switch markings: CSR 24, 48 VDC, catalogue No. 8847CB-001, serial No. 8916.

Figure 3. Two 600V fast recovery diodes (shown in yellow circle) and a bipolar diode (indicated by yellow arrow) attached to the incident switch terminals. The switch terminal points are marked TB1 to TB4.

The 600V fast recovery diodes attached to the incident switch were identified using the markings on the diodes, which read “GE A115M”. The diodes were manufactured by General Electric (GE) and identified as 3-Ampere rectifierdiodes and appear to have been used as surge protective devices at the switch terminals. Figure 4 shows the diodes after disconnecting from the switch terminals. An excerpt of the data sheet of the diodes is shown in Figure 5.

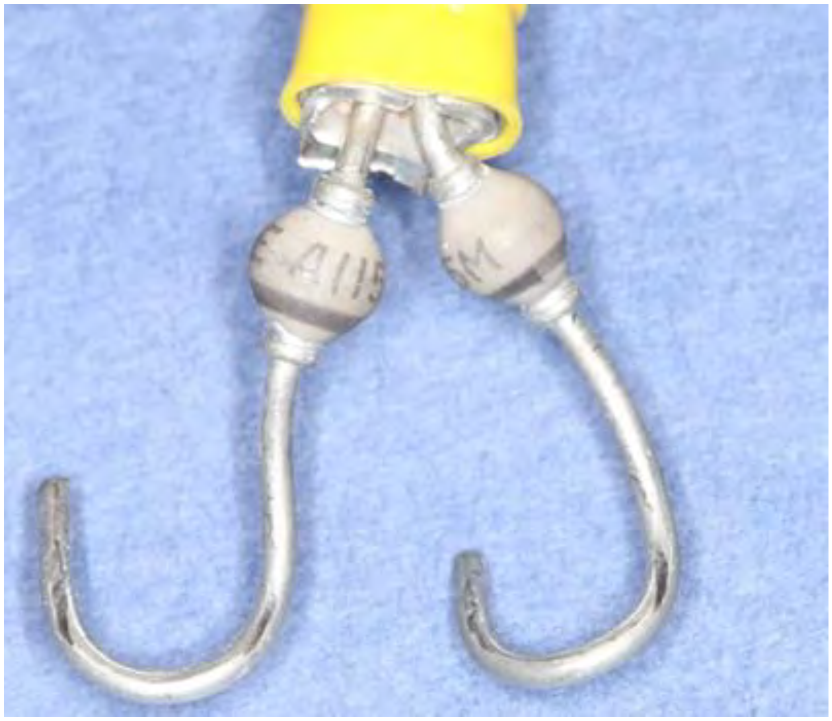


Figure 4. The 600V fast recovery diodes after disconnecting from the incident switch terminals.

RECTIFIERS
.25 TO 3 AMPERES

JEDEC	—	1N5059-62	1N4245-49	—	—	1N5624-27	—	—
GE TYPE	DT230	A14A-P	—	GER4001-7	A114A-M	—	A15A-N	A115A-M
SPECIFICATIONS								
$I_{FM(AV)}$ (A)	.25	1	1	1	1	3	3	3
@ T_A(°C)	50	100	55	75	55	70	70	55
$V_{RM(rep)}$ — Max. repetitive peak reverse voltage (V)								
600	—	1N5061	1N4247 *	GER4005	A114M	1N5626	A15M	A115M

Figure 5. An excerpt of the data sheet of the 600V fast recovery diodes.

The 200V Transil diode, also known as the bipolar diode, has the markings that read 1.5KE200. This indicates a nominal breakdown voltage of 200V and a peak pulse power of 1.5 kW (Figure 6). A technical publication by the switch manufacturer, Electroswitch, indicates that this diode is used to protect the switch internal circuits from transient over voltages. This technical publication also indicates that the Transil diode between terminals TB1 and TB2 of the switch "clips to 200V in 125 VDC control circuits."[1] The same publication states:

> *It [the diode] is also to protect the control bus and [sic] allowing this circuit to be used with sensitive static relays or other solid-state components.*

It appears from the technical document that a 200V diode is sufficient to protect the 125 VDC control switch against transient over voltages. However, the same type of protection is used for the 48 VDC control circuit of the incident switch. It is not clear why a voltage clipping closer to 48 VDC is not selected to protect this type of switch against transient over voltages.

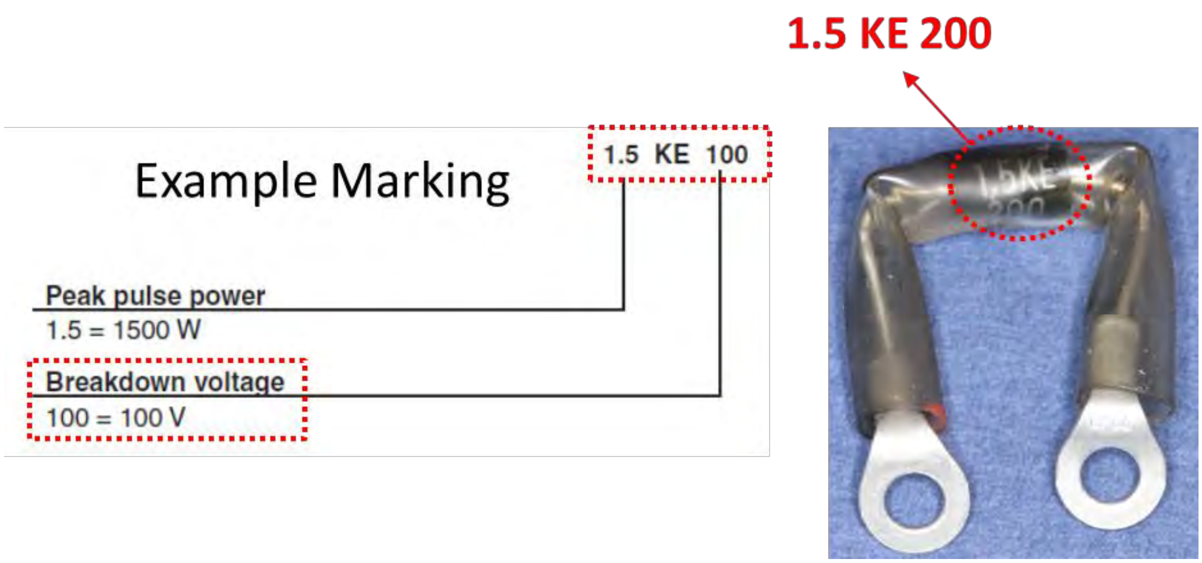


Figure 6. The transient voltage surge suppressor diode that was attached to the incident switch with markings that read 1.5KE200 indicating a breakdown voltage of 200V.

The Switch Operation

The internal circuit diagram of the switch shown in Figure 7 shows internal connections to the outside terminal points (TB1 to TB4). A schematic diagram of the switch control deck is shown in Figure 8. This type of circuit is known as the "Circuit B". It is designed for 1-second time delay and is equipped with "Anti-pumping" circuitry. TB1 and TB2 terminals are to be connected to 41 to 56 VDC line via outside relay contacts of S1/T and S2/C for the TRIP and CLOSE commands, respectively, as shown in Figure 7. The TB3 terminal provides power to the main actuating relay once the controls are activated. The switch control provides 1-second time delay using capacitor C1 and the adjustable resistor R2. This capacitor provides enough energy to K1 relay coil to keep the relay closed for 1 second after actuation. The Normally Closed

[1] Technical publication CSR-1, *Electrically Operated Control Switch Relay for both manual and supervisory control of power circuit breakers*, Effective January 1997, page 3.

contacts of K2 relay opens immediately after the actuation and de-energizes the K1 relay coil to provide the “Anti-pumping” function.

With reference to the circuit diagram in Figure 7, when the CLOSE position is commanded by S2/C, the linear solenoid, LS1, operates, setting the direction of the relay rotation to clockwise for CLOSE. This is achieved by the liner solenoid pushing a roller at the end of the solenoid’s drive arm so that the actuation of the rotary solenoid, CSR, causes the roller to strike and roll down to the left face of a cam inside the switch. This causes the rotation to occur in the clockwise direction to CLOSE position as illustrated in Figure 9.

When a CLOSE position is commanded through S2/C, the SL1 solenoid will be energized and the current flows through R1 to the K1 relay coil and the C1 capacitor, through the forward biased diode D3. The resistor R1 is designed to limit the capacitor charging current to about 1 ampere. Capacitor C1 charges quickly because of the low resistance of the forward biased diode D3 in its charging path. Simultaneously to the source voltage developing across C1, it also develops across the relay coil K1, which actuates the K1 relay and closes the DC line path from TB4 to CSR via closed contacts of K1. This action causes the CSR/N contacts to open and immediately open the K1 contact and de-energize CSR. In other words, the CSR rotary solenoid attempts to de-energize the K1 coil through CSR/N immediately after actuation. However, the C1 capacitor holds K1 closed by discharging through the K1 coil and R2. R2 is a variable resistor that provides the time delay to hold K1 for 1 second.

A second relay, K2, provides the Anti-pumping function. When the CSR rotary relay is actuated for either CLOSE or TRIP, the CSR/T,C contact closes, energizing the K2 relay coil. This actuates K2 and opens its normally-closed contacts which in turn opens the current path to the K1 relay coil. This action causes the CSR to energize (after 1 second time delay) and the relay returns to its normal position. At the same time, the normally-open contacts of K2 are closed that keeps the K2 coil energized as long as a TRIP or CLOSE command persists at the switch terminals. This prevents the CSR from operating again or “pump” until the TRIP or CLOSE commands are removed from the switch terminals.

A complete description of the control circuit function is described in the Technical Publication CSR-1, effective January 1997, by Electroswitch. A catalogue page that describes the switch characteristics is dated September 1987.

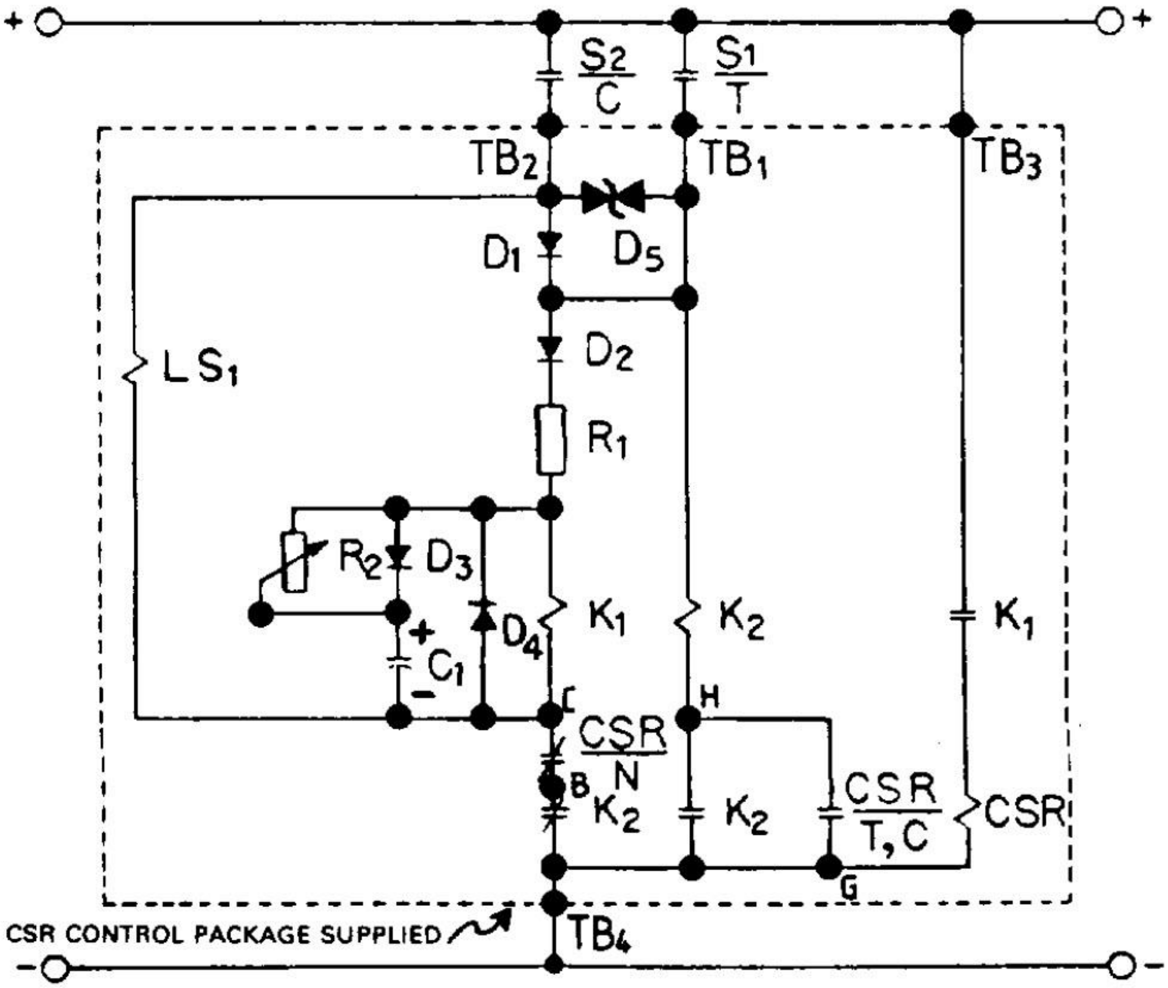


Figure 7. The switch internal control circuit-diagram.

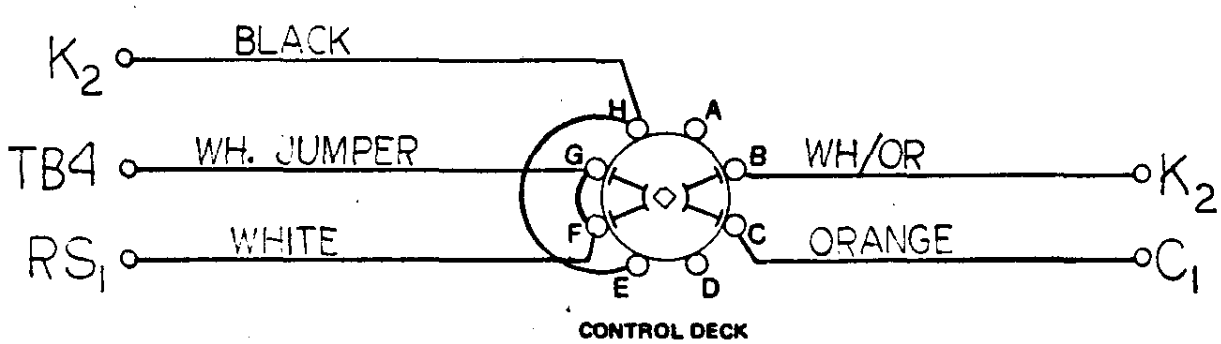


Figure 8. Schematic diagram of the switch control deck (deck 1).

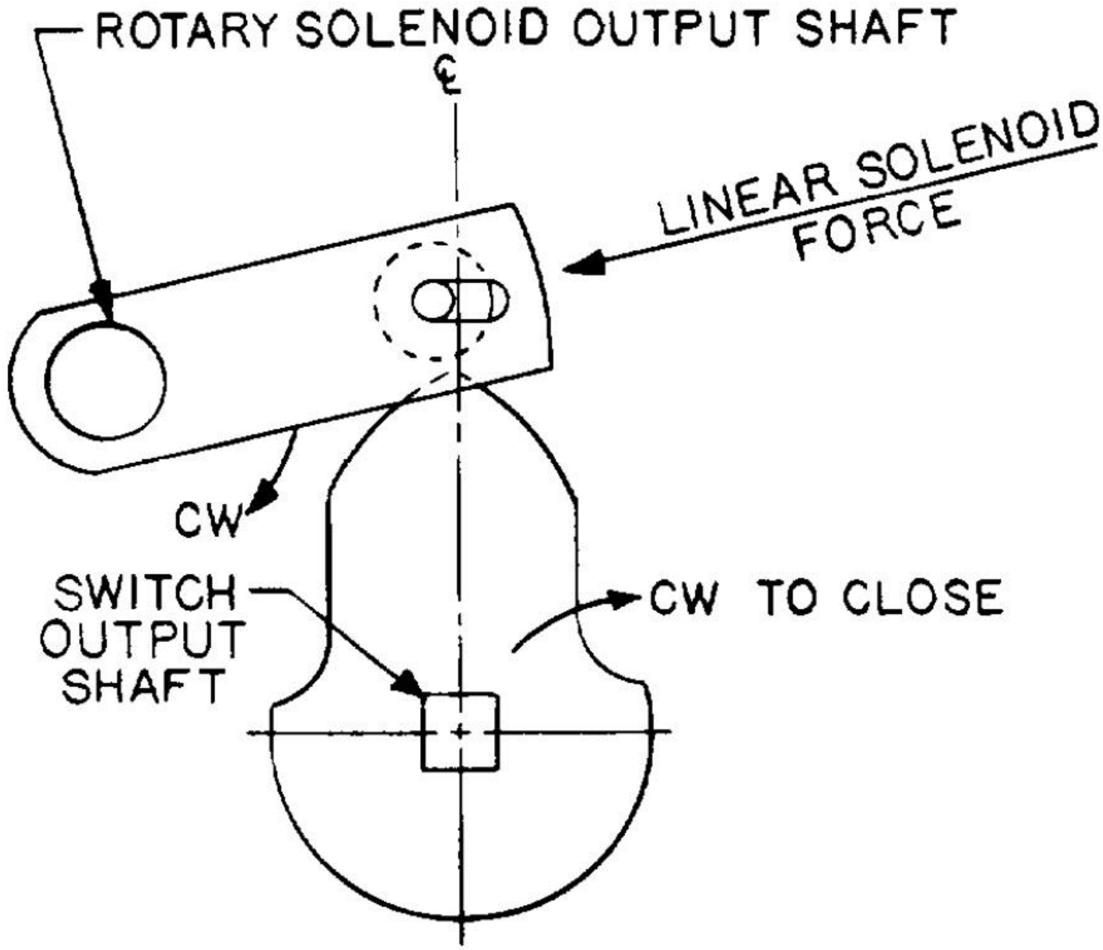


Figure 9. The cam mechanism for clockwise direction to CLOSE position: The linear solenoid is actuated when the CLOSE position is commanded at the switch terminal TB2.

Transient Protection

The technical document CSR-1 by the manufacturer indicates that control circuits of this type of switch will experience transients only if they occur during the switch operating mode. The document argues that no transient protection is needed for the "Circuit B" type switches[2] since this type of circuit does not remain on the DC bus while inactive. However, the document states: *A bipolar diode may be added if the CSR is used with sensitive static relays or other such devices*.[3]

2 Technical publication CSR-1, *Electrically Operated Control Switch Relay for both manual and supervisory control of power circuit breakers*, Effective January 1997, section: "Transient Protection", page 4.

3 Technical publication CSR-1, *Electrically Operated Control Switch Relay for both manual and supervisory control of power circuit breakers,* Effective January 1997, page 3.

The IEEE C37.90-2005 standard for relays and relay systems associated with electric power apparatus defines testing requirements for relays and relay systems used to protect and control the power apparatus. The IEEE C37.90.1-2012 standard for surge withstand capability (SWC) test for relays and relay systems associated with electric power apparatus specifies design tests for relays and relay systems that relate to immunity of this equipment to repetitive electrical transients. Test waveforms proposed for testing are oscillatory and fast transient surge withstand capabilities. Oscillatory waveforms are damped oscillating test waveform with a frequency of 1 MHz repeated in 2-second intervals with a magnitude of 2.5 kV. Fast transient waveforms are bursts of fast pulses with burst duration of 15 ms and 5 kHz repetition rate during the bursts. The technical document CSR-1 by the switch manufacturer states that testing satisfies an earlier revision of the C37.90 standard, namely ANSI/IEEE C37.90-1989.

IEEE standard C37.90.1-2012 also indicates that transients in low voltage circuits of substation control systems could peak from 100V to 10kV with decay time as long as 100ms. The standard also indicates that the available currents for this type of surge are not well documented and could be up to 100A in pulses and lower in oscillations.[4] These transients do not fall under the general fast transient waveforms that are normally used for surge withstand capability testing of the relay systems.

Laboratory Testing

Components attached to the incident switch, namely the 600V fast recovery diodes and the 200V Transil diode, were tested to measure their characteristics. Testing was performed using a curve tracer (Figure 10).

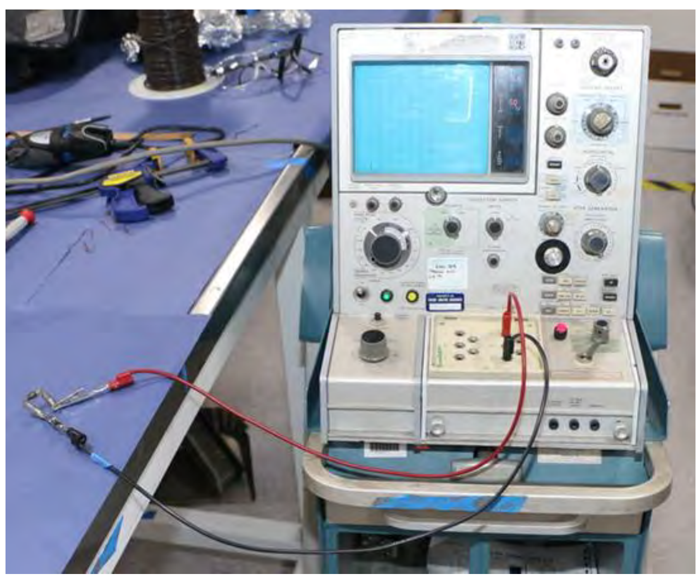


Figure 10. Curve tracer used to characterize the diodes of the incident switch

4 IEEE standard C37.90.1-2012, *IEEE Standard for Surge Withstand Capability (SWC) Test for Relays and Relay Systems Associated with Electric Power Apparatus*, page 40, section G.4.

It was discovered that the reverse voltages of all the diodes had changed but were greater than their specified values. The 200V Transil diode attached to the incident switch had peak reverse voltage of 240V rather than 200V (Figure 11). Also, the reverse breakdown voltage of the 600V fast recovery diodes had increased to approximately 1000V (Figure 12).

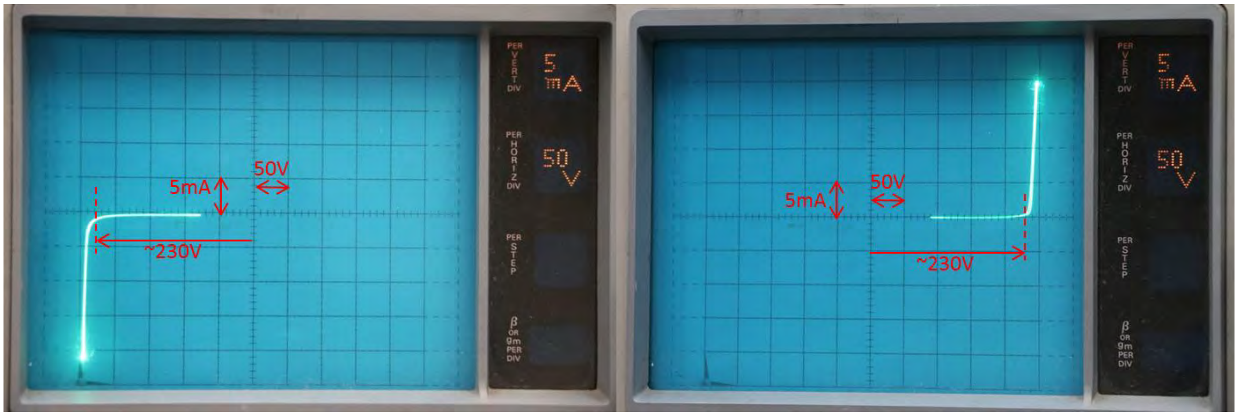


Figure 11. Measured Positive and Negative clamp voltages of 230V for the 200V Transil Diode.

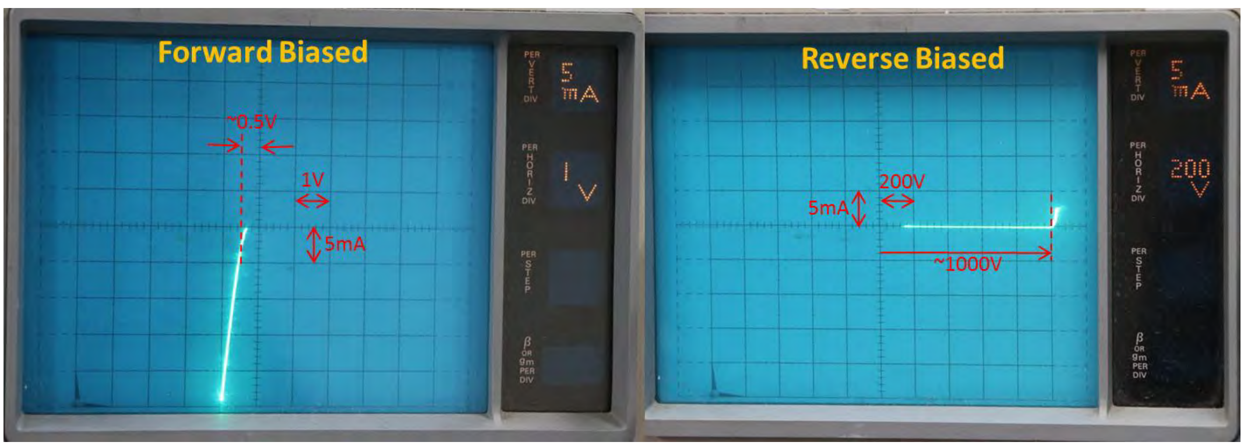


Figure 12. Measured reverse breakdown voltage of approximately 1000V for the 600 V rectifier diode.

Resistance measurements and diode testing was performed at different nodes of the exemplar and the incident switches. Measurements were made using a calibrated digital multi-meter (Fluke 289) for comparison between the exemplars and the incident switches. No significant difference was observed other than slight resistance increase at some of the ground terminals in the incident switch that were likely due to development of corrosion products at the electrical contacts as a result of aging. A loose terminal was also discovered at one of the ground terminal connections, but the contact resistance had not been notably changed. Table 1 shows the resistance and diode testing results of two exemplars and the incident switch. The measured contact points are in reference to the circuit diagrams shown in Figure 7 and Figure 8.

Table 1. Resistance and diode testing results of two exemplars and the incident switch. The measured contact points are in reference to the circuit diagrams shown in Figure 7 and Figure 8.

		Resistance measurements in Ω			Diode Testing		
Positive lead (+)	Negative Lead (-)	Exemplar #1	Exemplar #2	Incident Unit	Exemplar #1	Exemplar #2	Incident Unit
TB1	TB4	263 kΩ	276 kΩ	294 kΩ	Open	Open	Open
TB2	TB4	32 Ω	33 Ω	33 Ω	0.032 V	0.033 V	0.033 V
TB1	TB2	263 kΩ	268 kΩ	295 kΩ	Open	Open	Open
TB2	TB1	275 kΩ	277 kΩ	300 kΩ	0.58 V	0.58 V	0.58 v
TB1	H	1.7 kΩ	1.8 kΩ	1.7 kΩ	1.7 V	1.8 V	1.7 V
TB2	H	276 kΩ	280 kΩ	307 kΩ	2.22 V	2.27 V	2.20 V
H	TB2	264 kΩ	271 kΩ	298 kΩ	Open	Open	Open
TB1	C	263 kΩ	269 kΩ	295 kΩ	Open	Open	Open
TB2	C	32 Ω	33 Ω	32 Ω	0.032 V	0.033 V	0.032 V
H	C	264 kΩ	271 kΩ	297 kΩ	Open	Open	Open
C	H	276 kΩ	280 kΩ	309 kΩ	2.25 V	2.3 V	2.2 V
C	TB1	274 kΩ	279 kΩ	307 kΩ	0.61 V	0.62 V	0.61 V
C	TB2	32 Ω	33 Ω	32 Ω	0.032 V	0.033 Ω	0.032 Ω
B	C	0.08 Ω	0.08 Ω	0.08 Ω	0 V	0 V	0 V
B	TB4	0.11 Ω	0.11 Ω	0.21 Ω*	0 V	0 V	0 V
G	TB4	0.08 Ω	0.08 Ω	0.32 Ω*	0 V	0 V	0 V
G	H	276 kΩ	281 kΩ	309 kΩ	2.25 V	2.29 V	2.2 V
TB4	TB3	Open	Open	Open	Open	Open	Open

* Slight resistance increase at the ground connection in the incident switch likely due to corrosion and/or loose terminal as a result of aging.

Figure 13 shows the laboratory test setup that was used for the transient testing. A transient surge generator (TESEQ NSG 3040) was used for standard fast transient surge testing. An exemplar switch was energized by a DC power supply and IEC standard fast transient surge voltage applied to the CLOSE terminal of the switch. The transient voltage peak was increased up to 2 kV, at which point the exemplar switch failed without causing a CLOSE function.

A timer relay was used to switch on and off various DC voltage levels to the CLOSE terminal of an exemplar switch while the unit was energized with the same DC power supply. The switching CLOSE signal duration started with 300ms and the lowest voltage level that could cause a CLOSE function was measured. The signal duration was reduced and the process repeated. The fastest switching test using the available lab equipment was 10ms during which a 58V DC signal could cause the relay to close. The minimum voltage levels that could trigger a CLOSE function with various switching times were tested and the results are shown in the form of a plot in Figure 14.

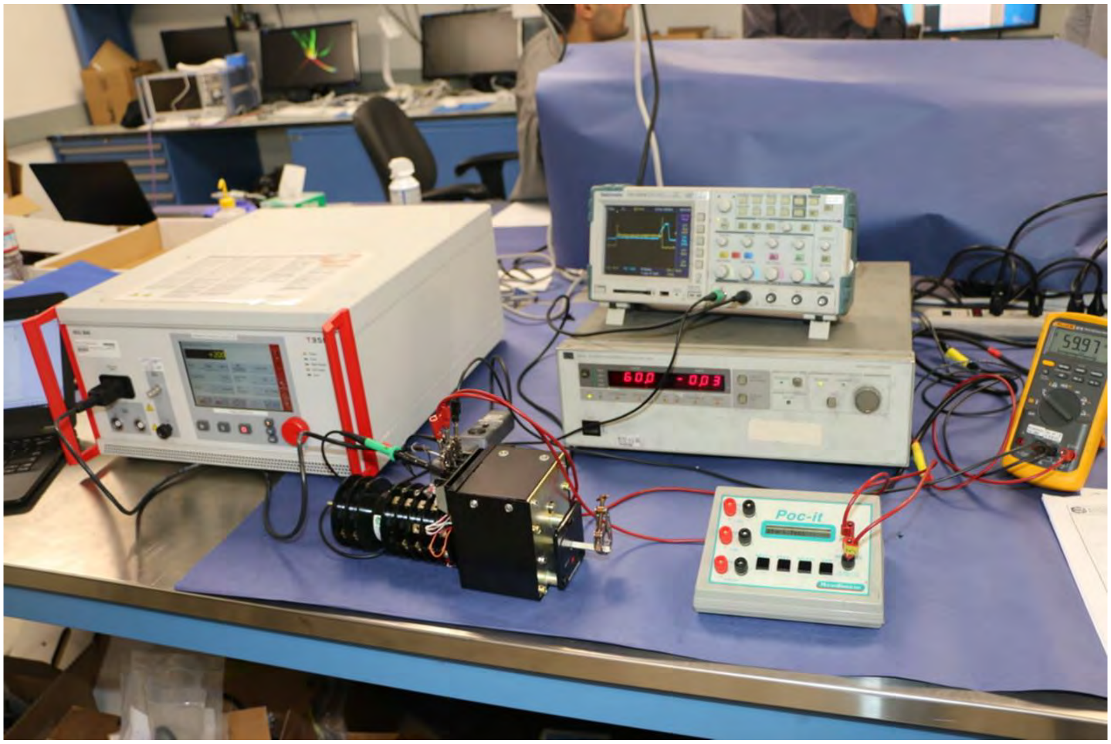


Figure 13. Laboratory test setup used for the transient testing.

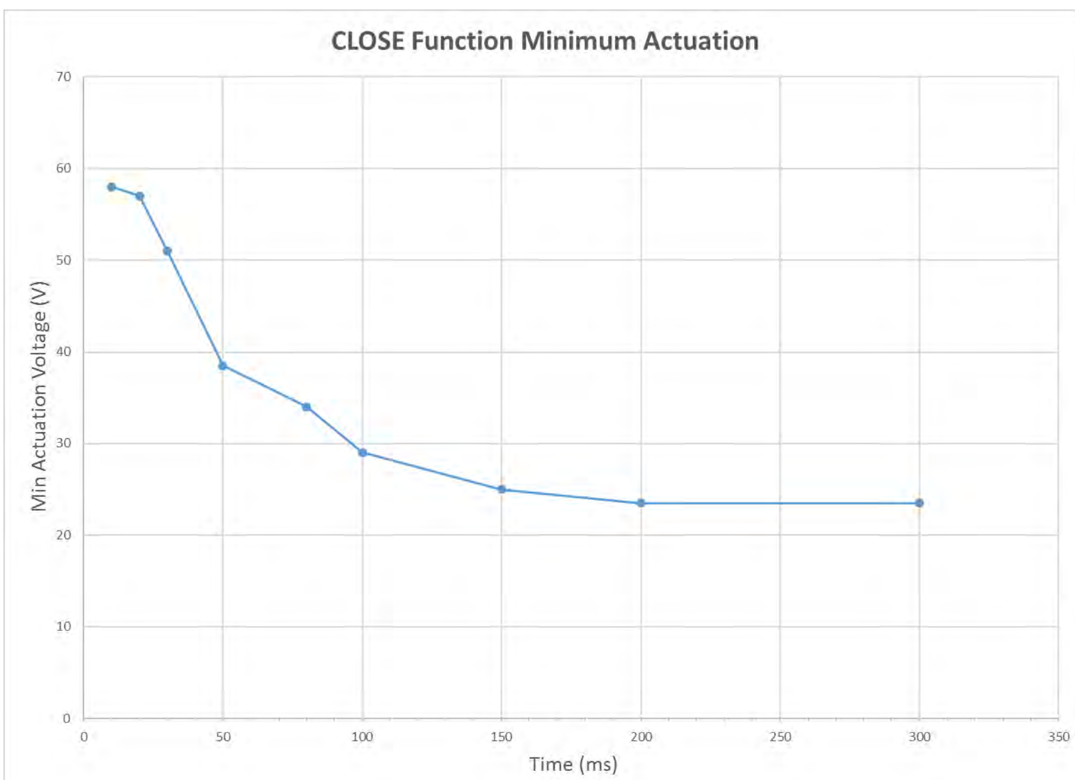


Figure 14. Minimum voltage levels that could trigger a CLOSE function with various switching times.

It was discovered that a 10 ms signal with a magnitude of 58V could assert a CLOSE command that would cause the switch to actuate and close. An oscilloscope image of such transient voltage is shown in Figure 15. Channel 1 (CH1) of the oscilloscope shows the voltage across an external relay that created the 10 ms, 58V signal to the CLOSE terminal of the test switch. Channel 2 (CH2) of the oscilloscope shows the current drawn by the test switch at the time of actuation. As can be seen from the oscilloscope image, after the 10 ms closing of the 58 V service voltage, the input voltage to the CLOSE terminal drops to approximately 20 V (one third of the DC supply voltage), but does not go to zero until after the switch actuation. The shape of the voltage signal after 10 ms until the time of the switch actuation suggests that the input current to the CLOSE terminal does not go to zero after 10 ms, but rather continues to flow despite the attempt by the external controls to shut down the CLOSE signal. It is likely that the current could not be interrupted due to large inductance of the linear solenoid, LS1, within the switch at the CLOSE circuit that would lead to continued supply of current and eventually the switch actuation to the CLOSE position. This shows that the switch is vulnerable to some system transients that could result in closing of the switch.

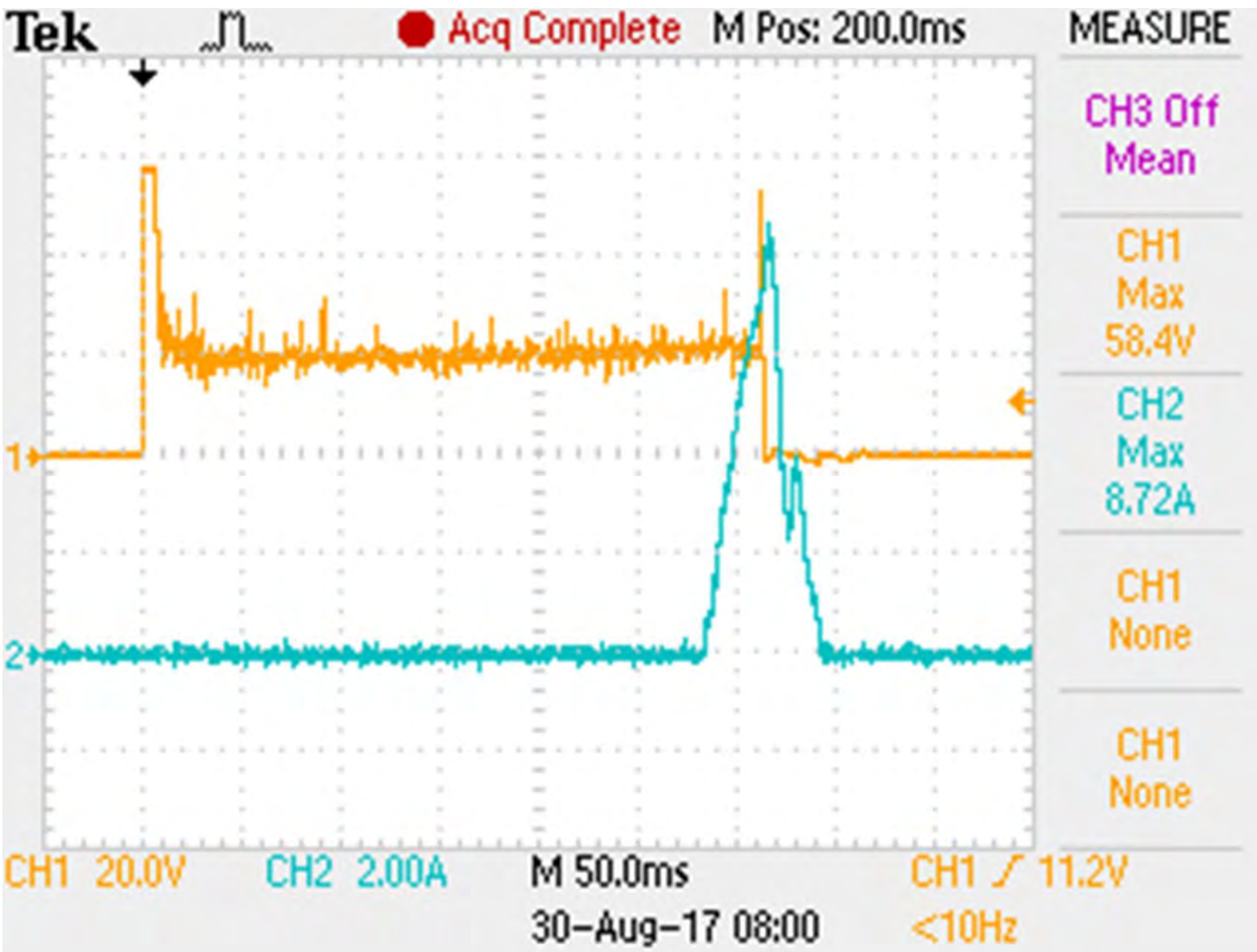


Figure 15. Oscilloscope image of a transient signal that led to closing of the switch.

Appendix B

Third Party Monitoring Company Work Order, 4/21/17

COSCO Fire Protection

7455 Longard Road • Livermore , CA 94551
P - (925) 455-2751 • F - (925) 455-2761

Service Call #: 17042212

Date: 4/21/17

Sales Terms: Net Ten (10) Days

Sales Representative:

Invoice To: PG&E

Product Line:
- [x] A& D / Electrical
- [ ] Extinguisher
- [ ] Special Hazards
- [ ] Other: ______
- [ ] Sprinkler / Mechanical
- [ ] Kitchen Hood
- [ ] Inspection

Contact Name:

Ph #: **Fx #:**

Job Location:
PG&E SUBSTATION Y
600 LARKIN ST,
SAN FRANCISCO, CA

Agreement Type:
- [x] Time & Material
- [ ] Price Not to Exceed $
- [ ] Lump Sum Fixed Price of $

Contact Name: [redacted]

Ph #: [redacted] **Fx #:**

Site Information:

	Yes	No
Inspection Due?	X	
Return Trip Required?		X
Customer Provided Fire Watch Required?		X
Cosco Sticker Posted?	X	

Panel Type: NOTIFIER NFS2-3030

Work Description: EMERGENCY SERVICE TO RETURN FIRE ALARM SYSTEM TO NORMAL AFTER FIRE IN SWITCH GEAR, SYSTEM IN ALARM, 1D007 & 1D008 SWITCH GEAR BEAM DETECTORS AND TROUBLE MAINT REQ. 1D044 BY TB-4, WAIT FOR CLEARANCE TO ENTER, CLEAN ALL BEAM DETECTORS IN SWITCH GEAR MAIN FLOOR AREA, RESET - ALL OK, UPLOAD DET. MAINT., CLEAN DETECTORS IN MEZZANINE SHOWING DIRTY, SYSTEM NORMAL UPON COMPLETION

Labor/ Material	Product #	Description	Qty	Unit/ Meas.	Unit Price	Extended Price
1	—	TRUCK CHARGE	1	—		
4	A&D	LABOR - KURT SHEETZ - 4/21/17	4	OT		
2	A&D	LABOR - KURT SHEETZ - 4/21/17	2	DT		

*NOTE: - FIRST VISION SCREEN IS OUT & ANNUNCIATOR IS NON-FUNCTIONAL = FURTHER TROUBLESHOOTING/REPAIR REQUIRED
- 1PGSM-4G RADIO NEEDS FIRMWARE UPGRADE PER HONEYWELL TECH SUPPORT - THEY ARE SENDING KITS

Authorized Custo[redacted]

Print Name & Title: [redacted] - Martin Maint Supr.

Customer PO:

Labor and Other Subtotal	
Material Subtotal	
Tax	
Shipping & Handling	
Total Due	

All work is subject to the terms & conditions on the back side of this work order.
All invoices are due net 10-days (no exceptions).

Date: 4/21/17

Technician: [signature] Sheetz

COSCO Fire Protection

7455 Longard Road • Livermore , CA 94551
- (925) 455-2751 • F - (925) 455-2761

Service Call #:	17050682
Date: 5/5/17	Sales Terms: Net Ten (10) Days
Sales Representative:	

Invoice To: PG&E

Product Line:
- [x] A& D / Electrical
- [ ] Extinguisher
- [ ] Special Hazards
- [ ] Other: ____________
- [ ] Sprinkler / Mechanical
- [ ] Kitchen Hood
- [ ] Inspection

Contact Name:

Ph #: **Fx #:**

Job Location:
PG&E SUB Y-LARKIN
600 LARKIN ST.
SAN FRANCISCO, CA

Agreement Type:
- [x] Time & Material
- [ ] Price Not to Exceed $
- [ ] Lump Sum Fixed Price of $

Contact Name: [redacted]

Ph #: [redacted]

Site Information:

	Yes	No
Inspection Due?	☐	☐
Return Trip Required?	☒	☐
Customer Provided Fire Watch Required?	☐	☒
Cosco Sticker Posted?	☒	☐

Panel Type: NOTIFIER - NFS2-3030

Work Description: SERVICE CALL TO TROUBLESHOOT FIRST VISION TOUCHSCREEN ANNUNCIATOR & DO FIRMWARE UPGRADE ON IP-GSM 4G & INVESTIGATE ALARM / FIRE DEPT. DISPATCH FROM YESTERDAY 5/4/17, ~~[illegible]~~ SYSTEM NORMAL UPON ARRIVAL, UPLOAD HISTORY, TROUBLESHOOT FIRST VISION W/ COMARK (MFG.), UPGRADE FIRMWARE ON IPGSM-4G - OK ~~[illegible]~~ PG&E ELECTRICIAN RE-TERMINATED SCADA OUTPUT WIRING FOUND LOOSE, GO OVER HISTORY REPORT W/ ANDY FROM 4/21/17, SYSTEM NORMAL UPON COMPLETION

Labor/ Material	Product #	Description	Qty	Unit/ Meas.	Unit Price	Extended Price
1	—	TRUCK CHARGE	1	—		
8	A&D	LABOR - KURT SHERTZ - 5/5/17	8	ST		
NOTE:	REMOVED FIRST VISION ANNUNCIATOR TO					
	SEND TO FACTORY FOR REPAIR					

Authorized Customer Signature: X [signature]

Print Name & Title: X ANDREW J. STEFFE SUB. FIRE MARSHAL

Customer PO:

All work is subject to the terms & conditions on the back side of this work order.
All invoices are due net 10-days (no exceptions).

Date: 5/5/17

Technician: [signature]

Labor and Other Subtotal	
Material Subtotal	
Tax	
Shipping & Handling	
Total Due	

Appendix C

Third Party Monitoring Company Alarm System Inspection and Test Report, 6/11/16

COSCO Fire Protection

Cosco Fire Protection
7455 Longard road
Livermore, CA 94551
925.455.2751
925.455.2761
www.coscofire.com

Cosco WO 1604-2715

Fire Alarm System Inspection and Test Report
Inspection Result: Fail

Report To: PG&E LARKIN	Location Inspected: PG&E LARKIN SAP #42568731
Street: 600 LARKING ST	Street: 600 LARKIN ST
City: SAN FRANCISCO	City: SAN FRANCISCO
State: CA Zip: 94108	State: CA Zip: 94108
Contact: [redacted]	Phone: [redacted] Email: [redacted]
Inspection Frequency: Annual	Inspection Date: 6/11/2016 Total Number Floors: 3
Monitoring Company: SCADA / CALIFORNIA SECURITY	Phone [redacted] Alarm Code: 670201
Monitoring Operator: OPERATOR	Operator Received Signal ☑ Yes ☐ N/A ☐ No Time:
Access Notes:	

Control/Auxiliary Panel General Information

System Type: ☑ Addressable ☐ Conventional Number of Zones ____________

	Control Panel Manufacturer & Model	Location	Batteries Volts	AH	Install Date	Normal	Load	Fail	Pass
0.01 Main Panel	NFS-3030D	Front Entry	12v	55ah	04/20/2011	13.46v	51ah	☐	☑
0.02 Dialer	UDACT							☐	☑

Site Inspection Monitoring Information		No	N/A	Yes
1.01	Did the Monitoring Company Receive the Appropriate Signal?	☐	☐	☑
1.02	Alarm Signal Received?	☐	☐	☑
1.03	Supervisory Signal Received?	☐	☐	☑
1.04	Trouble Signal Received?	☐	☐	☑

Site Inspection General Information		No	N/A	Yes
2.01	Existing alarm or trouble conditions found upon arrival?	☐	☐	☑
2.02	Is the FACP accessible and unobstructed?	☐	☐	☑
2.03	Does building occupant/management have key to control panel door?	☐	☐	☑
2.04	Are there special releasing zones within the building? *Location:* ____________	☐	☑	☐

Fire Alarm System General Information		No	N/A	Yes
3.01	Operating instructions at panel?	☐	☐	☑
3.02	A/C power disconnect source identified on panel? *Location:* ____________	☐	☐	☑
3.03	All AC Power circuit breaker(s) locked in the on positions?	☐	☐	☑

COSCO Fire Protection

Fire Alarm System Inspection/Test

Cosco WO 1604-2716

System Control Panel Check Points		No	N/A	Yes
4.01	AC power lamp on?	☐	☐	☑
4.02	Alarm signal, when silenced automatically reinitiated upon subsequent alarm? (if addressable system)	☐	☐	☑

Annunciator Panel		No	N/A	Yes
5.01	Annunciator - Ancillary switches operational?	☐	☑	☐
5.02	Annunciator - Common trouble signal operational?	☐	☑	☐
5.03	Annunciator - Alarm or supervisory signal zone correctly identified?	☐	☑	☐
5.04	Annunciator - Input wiring from FACP is supervised?	☐	☑	☐
5.05	Annunciator - Lamp Test operational and all indicators verified?	☐	☑	☐

System Printer		No	N/A	Yes
6.01	Printer connected and operational?	☐	☑	☐
6.02	Printer is monitored for "Paper Out" trouble signal?	☐	☑	☐
6.03	Printer paper advances automatically such that print record is visible?	☐	☑	☐
6.04	Printer records all events, including supervisory and trouble conditions?	☐	☑	☐
6.05	Printer time and date of each event are recorded correctly?	☐	☑	☐

Voice Evac Notification		No	N/A	Yes
7.01	Voice Evac - Amplifiers/Tone Generators visually inspected and appears in good physical condition	☐	☑	☐
7.02	Voice Evac - System sound quality & clarity acceptable?	☐	☑	☐
7.03	Voice Evac - Microphone in place and operational?	☐	☑	☐
7.04	Voice Evac - Area/floor selection switches operational?	☐	☑	☐

Fireman Phone System		No	N/A	Yes
8.01	Fireman Phone - Call in indicator operational?	☐	☑	☐
8.02	Fireman Phone - Jacks visually inspected, tested and found to be operational?	☐	☑	☐
8.03	Fireman Phone - Off hook indicator operational?	☐	☑	☐
8.04	Fireman Phone - Sets in good conditional and operational?	☐	☑	☐
8.05	Fireman Phone - Call in signal operational?	☐	☑	☐

Fire Pump		No	N/A	Yes
9.01	Fire Pump - Auto OFF conditional signal received?	☐	☑	☐

10.01 Auxiliary Functions

10.02 Door Holder	Yes	No	10.03 Elevator Recall	Yes	No
	☑	☐		☑	☐

COSCO Fire Protection

Fire Alarm System Inspection/Test

Cosco WO

11.01 Auxiliary Cont.

Ref	Other Description	Location	Qty	Fail	Pass
11.01				☐	☐
11.02				☐	☐
11.03				☐	☐
11.04				☐	☐
11.05				☐	☐
11.06				☐	☐
11.07				☐	☐
11.08				☐	☐
11.09				☐	☐
11.10				☐	☐
11.11				☐	☐
11.12				☐	☐
11.13				☐	☐
11.14				☐	☐
11.15				☐	☐
11.16				☐	☐
11.17				☐	☐
11.18				☐	☐
11.19				☐	☐
11.20				☐	☐
11.21				☐	☐
11.22				☐	☐
11.23				☐	☐
11.24				☐	☐
11.25				☐	☐
11.26				☐	☐
11.27				☐	☐
11.28				☐	☐
11.29				☐	☐
11.30				☐	☐

12.01 Additional Panel

Ref	Additional Panel	Control Panel Manufacturer & Model	Panel Location	Batteries						Fail	Pass
				Volts	AH	Install Date	Normal	Load	Circuit Breaker Loc.		
12.01										☐	☐
12.02										☐	☐
12.03										☐	☐
12.04										☐	☐
12.05										☐	☐
12.06										☐	☐
12.07										☐	☐
12.08										☐	☐
12.09										☐	☐
12.10										☐	☐
12.11										☐	☐
12.12										☐	☐
12.13										☐	☐
12.14										☐	☐
12.15										☐	☐
12.16										☐	☐
12.17										☐	☐
12.18										☐	☐
12.19										☐	☐
12.20										☐	☐
12.21										☐	☐
12.22										☐	☐
12.23										☐	☐
12.24										☐	☐
12.25										☐	☐
12.26										☐	☐
12.27										☐	☐
12.28										☐	☐
12.29										☐	☐
12.30										☐	☐

COSCO Fire Protection **Fire Alarm System Inspection/Test** Cosco WO

13.01 Notification Test Results

Ref	Floor	Appliance Type	Qty.	Fail	Pass	Comments
13.01	Inside facility	Horn / Strobe	All	☐	☑	
13.02	Outside bldg.	Horn	1	☐	☑	
13.03				☐	☐	
13.04				☐	☐	
13.05				☐	☐	
13.06				☐	☐	
13.07				☐	☐	
13.08				☐	☐	
13.09				☐	☐	
13.10				☐	☐	
13.11				☐	☐	
13.12				☐	☐	
13.13				☐	☐	
13.14				☐	☐	
13.15				☐	☐	
13.16				☐	☐	
13.17				☐	☐	
13.18				☐	☐	
13.19				☐	☐	
13.20				☐	☐	
13.21				☐	☐	
13.22				☐	☐	
13.23				☐	☐	
13.24				☐	☐	
13.25				☐	☐	
13.26				☐	☐	
13.27				☐	☐	
13.28				☐	☐	
13.29				☐	☐	
13.30				☐	☐	

14.01 Initiation Field Device Test Results

Ref	Device Location	Device Type	Device Address	Test Data					
				Visual	Supv.	Sensitivity	Fail	Pass	Date
.01	ENTRY LOBBY	Smoke Detector - Photo	L1D001	☑	☐		☐	☑	5/26/2016
14.02	BATTERY ROOM	Smoke Detector - Photo	L1D002	☑	☐		☐	☑	5/26/2016
14.03	CONTROL ROOM	Smoke Detector - Photo	L1D003	☑	☐		☐	☑	5/26/2016
14.04	CONTROL ROOM	Smoke Detector - Photo	L1D004	☑	☐		☐	☑	5/26/2016
14.05	CONTROL ROOM	Smoke Detector - Photo	L1D005	☑	☐		☐	☑	5/26/2016
14.06	SWITCH GEAR	Beam Dectector	L1D006	☑	☐		☐	☑	5/26/2016
14.07	SWITCH GEAR	Beam Dectector	L1D007	☑	☐		☐	☑	5/26/2016
14.08	SWITCH GEAR	Beam Dectector	L1D008	☑	☐		☐	☑	5/26/2016
14.09	CAPACITOR	Smoke Detector - Photo	L1D009	☑	☐		☑	☐	6/11/2016
14.10	CAPACITOR	Smoke Detector - Photo	L1D010	☑	☐		☐	☑	6/11/2016
14.11	SERVICE ROOM	Smoke Detector - Photo	L1D011	☑	☐		☐	☑	5/26/2016
14.12	MEZZANINE #1	Smoke Detector - Photo	L1D012	☑	☐		☐	☑	5/26/2016
14.13	MEZZANINE #2	Smoke Detector - Photo	L1D013	☑	☐		☐	☑	5/26/2016
4.14	MEZZANINE#3	Smoke Detector - Photo	L1D014	☑	☐		☐	☑	5/26/2016
14.15	LOW VOLTAGE	Smoke Detector - Photo	L1D015	☑	☐		☐	☑	5/26/2016
14.16	LOW VOLTAGE	Smoke Detector - Photo	L1D016	☑	☐		☐	☑	5/26/2016
14.17	LOW VOLTAGE	Smoke Detector - Photo	L1D017	☑	☐		☐	☑	5/26/2016
14.18	CAPACITOR	Smoke Detector - Photo	L1D018	☑	☐		☐	☑	5/26/2016
14.19	CAPACITOR	Smoke Detector - Photo	L1D019	☑	☐		☐	☑	5/26/2016
14.20	CABLE AREA BSMNT	Smoke Detector - Photo	L1D020	☑	☐		☐	☑	5/26/2016
14.21	CABLE AREA BSMNT	Smoke Detector - Photo	L1D021	☑	☐		☐	☑	5/26/2016
14.22	CABLE AREA BSMNT	Smoke Detector - Photo	L1D022	☑	☐		☐	☑	5/26/2016
14.23	CABLE AREA BSMNT	Smoke Detector - Photo	L1D023	☑	☐		☐	☑	5/26/2016
14.24	CABLE AREA BSMNT	Smoke Detector - Photo	L1D024	☑	☐		☐	☑	5/26/2016
14.25	CABLE AREA BSMNT	Smoke Detector - Photo	L1D025	☑	☐		☐	☑	5/26/2016
14.26	CABLE AREA BSMNT	Smoke Detector - Photo	L1D026	☑	☐		☐	☑	5/26/2016
14.27	CABLE AREA BSMNT	Smoke Detector - Photo	L1D027	☑	☐		☐	☑	5/26/2016
14.28	CABLE AREA BSMNT	Smoke Detector - Photo	L1D028	☑	☐		☐	☑	5/26/2016
14.29	CABLE AREA BSMNT	Smoke Detector - Photo	L1DO29	☑	☐		☐	☑	5/26/2016

COSCO Fire Protection

Fire Alarm System Inspection/Test Cosco WO

14.01 Initiation Field Device Test Results

Ref	Device Location	Device Type	Device Address	Test Data: Visual	Supv.	Sensitivity	Fail	Pass	Date
14.59	DELUGE PULLSTATION	Manual Fire Alarm Box - Pull	L1M031	☑	☐		☐	☑	5/26/2016
14.60	DELUGE PULLSTATION	Manual Fire Alarm Box - Pull	L1M032	☑	☐		☐	☑	5/26/2016
14.61	BASEMENT	Waterflow Switch	L1M130	☑	☐		☐	☑	5/26/2016
14.62	BASEMENT	Valve Tamper Switch	L1M131	☑	☑		☐	☑	5/26/2016
14.63	REGULATION ROOM	Beam Dectector	L1D045	☑	☑		☐	☑	5/26/2016
14.64	FAN 1	Duct Dectector	L1D046	☑	☑		☐	☑	5/26/2016
14.65	FAN 2	Duct Dectector	L1D047	☑	☑		☐	☑	5/26/2016
14.66	FAN 3	Duct Dectector	L1D048	☑	☑		☐	☑	5/26/2016
14.67	FAN 4	Duct Dectector	L1D049	☑	☑		☐	☑	5/26/2016
14.68	FAN 5	Duct Dectector	L1D050	☑	☑		☐	☑	5/26/2016
14.69	FAN 7	Duct Dectector	L1D052	☑	☑		☐	☑	5/26/2016
14.70	FAN 8	Duct Dectector	L1D053	☑	☑		☐	☑	5/26/2016
14.71	FAN 9	Duct Dectector	L1D054	☑	☑		☐	☑	5/26/2016
14.72	WET SYSTEM	Waterflow Switch	L1MO73	☑	☐		☐	☑	5/26/2016
14.73	FAN 6	Duct Dectector	L1D051	☑	☑		☐	☑	5/26/2016
14.74				☐	☐		☐	☐	
14.75				☐	☐		☐	☐	
14.76				☐	☐		☐	☐	
14.77				☐	☐		☐	☐	
14.78				☐	☐		☐	☐	
14.79				☐	☐		☐	☐	
14.80				☐	☐		☐	☐	
14.81				☐	☐		☐	☐	
14.82				☐	☐		☐	☐	
14.83				☐	☐		☐	☐	
14.84				☐	☐		☐	☐	
14.85				☐	☐		☐	☐	
14.86				☐	☐		☐	☐	
14.87				☐	☐		☐	☐	

COSCO Fire Protection

Inspection Results and Comments

Cosco WO 1604-2715

Item	Deficiencies
14.09	After testing device the detector came into trouble (Maint. Req.) PGE personnel were unable to gain acces...
Note	the detector due to height (20') as well as the placement (center of room). PGE requests that when they are
	conducting TI inside the Capacitor Bank that Cosco comes and conducts repair on the detector or possibly
Note	remove it from the system.
Note	
Note	
Note	
Note	
Note	
Note	
Note	
Note	
Note	

LIABILITY RELEASE STATEMENT: The Owner and/or its designated representative acknowledge that the Owner has full responsibility for the operating condition of the fire protection system(s) including its component parts at the time of this inspection. This inspection/test report is governed by terms and conditions of Cosco Fire Protection Inspection signed agreement. Without in any way limiting such terms and conditions, the Owner acknowledges that the Contractor does not have any obligation to correct any deficiencies Contractor has identified in report and Owner shall have full responsibility for corrections of any such deficiencies. As an additional service, however, the Owner and/or its designated representative may enter into a separate, written repair or maintenance contract with Contractor for the correction of such deficiencies. During our work in your building, our representatives may have noticed items on your fire protection system that may need further investigation. These items are not part of the normal NFPA Standards inspection, testing or maintenance functions, but we are providing you with notice of these concerns as a courtesy. This does not constitute or represent that we have performed a full analysis of fire protection system(s) in this building and there may be other items of concern that we have not identified because this type of analysis is beyond the scope of what we were hired to do in accordance with NFPA Standards.

Customer Name [redacted]	Inspector Name Zachary Wildman
Customer Signature Not Available ☐ [redacted]	Inspector Signature [signature]
6/11/2016	Date 6/11/2016

COSCO Fire Protection — Fire Alarm System Inspection/Test

Cosco WO 1604-2715

Although these comments are not the results of any engineering review, the following improvements are recommended:

Disable the following points: M077,M078,M079,M080 (release ckts), M040, M041, M042, M043, M044, M045, M046, M047, M048, M049, M050, M051, M052, 053, M054, M055, M056, M057 (Fan shutdowns). Pull output 1 , 2 & 3 from NAC circuit (open the 3rd panel on the FACP, NAC circuit is inside)to disable notification devices.

System Descriptions/Tech Notes:

Completed Annual fire alarm system inspection as per NFPA 72.

LIABILITY RELEASE STATEMENT: The Owner and/or its designated representative acknowledge that the Owner has full responsibility for the operating condition of the fire protection system(s) including its component parts at the time of this inspection. This inspection/test report is governed by terms and conditions of Cosco Fire Protection Inspection signed agreement. Without in any way limiting such terms and conditions, the Owner acknowledges that the Contractor does not have any obligation to correct any deficiencies Contractor has identified in report and Owner shall have full responsibility for corrections of any such deficiencies. As an additional service, however, the Owner and/or its designated representative may enter into a separate, written repair or maintenance contract with Contractor for the correction of such deficiencies. During our work in your building, our representatives may have noticed items on your fire protection system that may need further investigation. These items are not part of the normal NFPA Standards inspection, testing or maintenance functions, but we are providing you with notice of these concerns as a courtesy. This does not constitute or represent that we have performed a full analysis of fire protection system(s) in this building and there may be other items of concern that we have not identified because this type of analysis is beyond the scope of what we were hired to do in accordance with NFPA Standards.

Customer Name [redacted]	Inspector Name Zachary Wildman
Customer Signature [redacted]	Inspector Signature
Date 6/11/2016	Date 6/11/2016

Appendix D

Circuit Breaker Maintenance Form, Metalclad Circuit Breaker Mechanical Tests Service and Functional Performance Test

Pacific Gas and Electric Company

Circuit-Breaker Maintenance Form
Metalclad Circuit Breaker Mechanism Service

TD-3322M-F

Substation LARKIN ETS.12-12568	CB No. CB76 40992692	CB Serial No. 0224A2835032	Type AM 13.8 1000 3H
Manufacturer GE	Counter Before 843	Counter After 853	Date 9-20-16
Crew [redacted]		SAP Order No. 42687218	
Mechanism Service ✓ 100% ACC	BOA™ Condition Code		Condition/Trouble

Mechanism Service and Cubicle Maintenance:

- **Important Notes:** Perform and document the necessary troubleshooting tests if there are **any** circuit-breaker malfunctions. If necessary, check and make any mechanical adjustments listed in the manufacturers' instruction manuals. To ensure service reliability and safety, immediately correct **any** conditions that may cause malfunctions.
- **Always** use the manufacturer's instruction manual as a reference for more detailed information, including safety precautions, when performing **any** maintenance.
- Since there are many different styles of metalclad switchgear, perform only the maintenance checks that apply to the style being maintained.
- For metalclad breakers that use rectified ac-to-dc control power, limit the number of testing operations to no more than 10 times in 10 minutes and 20 times in 1 hour. Apply the load to the rectifier for no more than one second at a time.

Initial when complete. (Use NA, instead of initials, for any items that do not apply.)

YT SP	Check the job-planning requirements in the *Substation Maintenance and Construction Manual (SMCM)*, "Circuit Breakers," Section 5, "Metalclad Switchgear."*
YT SP	Clear the circuit breaker and make it safe for maintenance.* **Caution** - Properly discharge the static charges on the vacuum bottles and the VCB high-voltage components.*
YT SP	Thoroughly inspect the entire circuit breaker, including all of the items on this form. Correct any unsatisfactory conditions.
YT SP	Thoroughly check the entire circuit breaker for any loose, missing, worn, cracked, or damaged parts.
YT SP	Check the physical condition of all the springs, cotter pins, keepers, bolts, and other fasteners.
YT SP	Ensure that all of the electrical wire terminations are tight and not corroded.
N/A	Check Control circuit insulation integrity. The minimum acceptable insulation resistance is 2 Megohms.
YT SP	Ensure that the latch-check switch and all of the auxiliary switches, microswitches, X-Y anti-pump relays, and seal stacks have good electrical connections. Check accessible relay and auxiliary-switch contacts for excessive burning or pitting. Check the mechanical condition of switches and relays, including their operating arms and linkages. Clean and lubricate the secondary-control coupling contacts with a very thin film of Penetrox™ contact grease lubricant.
YT SP	Check the condition of the motor assemblies.
YT SP	Check all of the insulators and bushings for evidence of moisture or other contamination. Carefully inspect organic insulation for signs of "tree tracking" or for a white, powdery deposit in the vicinity of a conductor. This condition indicates a corona discharge, which, if allowed to continue, will result in failure of the insulation.
YT SP	Check the condition of the primary-coupling contacts on the circuit breaker. Look for evidence of heat, binding, striking, discoloration, or uneven pressures on the cluster fingers. Refer to the manufacturer's instruction manual for any specific spring-pressure requirements. Check the cluster springs for signs of heat. Clean the circuit breaker's primary connections and lubricate them with Mobilegrease 28.
N/A	Ensure that the mechanism shock absorbers and/or dashpots are operating properly. Use the manufacturer's instruction manual as a reference. Inspect the dashpots for leaks and for the proper oil levels. Clean, repair, and add or replace oil, as necessary.

Continued on next page

Initial when complete. (Use NA, instead of initials, for any items that do not apply.)

N/A	Clean and closely inspect any vacuum or SF_6 interrupter bottles. Clean their high-voltage enclosures. Look for any cracks, including in the area of the metal-to-insulation seals at both ends of the bottles and at the midband ring. Inspect the interrupter linkages for loose, broken, or missing parts. Check the condition of all the cotter pins, ring fasteners, and keepers.
YT SP	Slow-close the circuit breaker with the manual closing device, per the manufacturer's instructions. Check for dragging and binding of the shafts, shock absorbers, and linkage parts. For ACBs, also ensure that the arc-puffer assemblies are working properly.
N/A	Notify the distribution operator before testing the alarms, relays, or reclosers. Use the control circuit's auxiliary connective cords, or rack the circuit breaker into the test position, then run the recloser to lockout by activating the protective relays. On circuit breakers with electro-mechanical relays, test three-phase simultaneous targeting. Verify the trip-free operation of the circuit breaker. Verify that the alarms, relays, and recloser are working properly. Reset the recloser by electrically closing the circuit breaker. Record the reclosing and lockout times, and update the recloser relay card. Watch for any circuit-breaker malfunctioning that requires more extensive troubleshooting for permanent correction. *
YT SP	Verify that the circuit-breaker operations counter, all the red and green lights, and the mechanical position semaphore are working properly.
YT SP	Trip the circuit breaker with the emergency or mechanical-maintenance trip device. Verify that the 69 lockout device prevents further electrical operation. Manually reset the lockout device.
YT SP	Thoroughly clean and lubricate the entire mechanism according to the procedures in *SMCM*, "Circuit Breakers," Section 10, "Cleaning and Lubricating Mechanisms."*
YT SP	**Properly clean and lubricate all of the trip shafts.**
YT SP	Ensure that the door seals and compartment filters are in good condition and are keeping the mechanism clean and dry. Add, repair, or replace seals or filters, if necessary. Ensure that all of the compartment heaters are working.
YT SP	Determine and record the percentage wear of all the contacts and interrupters, including those related to vacuum bottles. Perform a high-pot test and measure the contact erosion on all vacuum bottles. Replace any contacts or interrupters found with 75% or greater wear. Clean all of the accessible contacts. While inspecting the main and arcing contacts, check for unequal or uneven wear, coke build-up, heavy pitting, or grooves. Any of these may indicate incorrect contact pressure. If any of these conditions are found, check the contact pressure (refer to *SMCM*, "Circuit Breakers," Section 3, "Diagnostic Tests"). In the chart below, write NA for any checks that do not apply to the type of circuit breaker being serviced. **Note:** Vacuum bottles without factory-established reference dimensions must still have the percentage wear data taken and recorded.*

Phase: From Front of CB*	% Wear, Main Contacts	% Wear, Arcing Contacts	Reference Dimension*	CB Closed Dimension	% Wear, Interrupters
Left*	5	10	N/A	N/A	N/A
Middle*	5	10	|	|	|
Right*	5	10	|	|	|

N/A	With the circuit breaker open, perform high-pot tests on the vacuum bottles and on the SF_6 cylinders, if specified by the manufacturer. Use the test voltage specified in the manufacturer's instruction book. Test voltage: _____ **Note:** Some metalclad VCBs may have surge suppressors connected to the vacuum bottles. The surge suppressors must be disconnected before the high-pot test is performed.* A-A _____ (Pass or fail) B-B _____ (Pass or fail) C-C _____ (Pass or fail)

*Indicates additional information available in *SMCM*, "Circuit Breakers."

Continued on next page

Pacific Gas and Electric Company

Circuit-Breaker Maintenance Form
Metalclad Circuit Breaker Mechanism Service

TD-3322M-F14

Initial when complete. (Use NA, instead of initials, for any items that do not apply.)

YT SP

Use a 2,500 V megger to test the insulation resistance on the primary voltage circuits. With the circuit breaker closed, test each phase from phase-to-phase and phase-to-ground. With the circuit breaker open, test each pole to ground, and test across each phase. The minimum acceptable insulation resistance is 10 megohms per line-to-line kV of the primary voltage. (For low-voltage circuit breakers in the 480 Vac range, 2 megohm is the minimum.)

Circuit Breaker - Open

Test Points	Pole 1 to Ground	Pole 2 to Ground	Pole 3 to Ground	Pole 4 to Ground	Pole 5 to Ground	Pole 6 to Ground	Pole 1 to Pole 2*	Pole 3 to Pole 4*	Pole 5 to Pole 6*
Results (MΩ)	12.2GΩ	10.6GΩ	9.6GΩ	9.5GΩ	7.3GΩ	7.5GΩ	463MΩ	1.06GΩ	358 MΩ

Circuit Breaker - Closed

Test Points	Pole 1 to Ground	Pole 3 to Ground	Pole 5 to Ground	Pole 1 to Pole 3	Pole 3 to Pole 5	Pole 1 to Pole 5
Results (MΩ)	13GΩ	9.6GΩ	7.5GΩ	24.6GΩ	19.3GΩ	25.2GΩ

YT SP

Perform an absolute "minimum-to-trip" test on dc-operated circuit breakers with a trip latch that is directly linked to the trip coil via a trip plunger, trip armature, etc. For all other designs, verify the circuit breaker will trip at the lowest voltage level listed in the operating voltage range on the nameplate.

70 Vdc to trip

Perform an absolute "minimum-to-close" test on dc-operated circuit breakers with a close latch that is directly linked to the close coil via a close plunger, closing armature, etc. For all other designs, verify the circuit breaker will close at the lowest voltage level listed in the operating voltage range on the nameplate.

Test **solenoid-close** circuit breakers that draw more than 15 amps of close coil current, and ensure they close at 80 percent of nominal control voltage.

90 Vdc to close

YT SP

Test the anti-pump feature of the control circuit.*

YT SP

Perform an FPT for a "return-to-service" benchmark for trending purposes. Record the results on theTD-3322M-F13, "Functional-Performance Test" form. (See *SMCM*, "Circuit Breakers," Section 13, "Forms.")
Contacts/seals tested: Trip-ACON Close-END

YT SP

Also perform main-contact timing tests. This ensures that the main contacts and mechanism results are within the manufacturer's specifications.

Manufacturer's opening time specification: N/A Tested opening time: 33.4

Manufacturer's closing time specification: N/A Tested closing time: 41.3

YT SP

Operate the circuit breaker from all the available locations, including by SCADA, if applicable.

YT SP

Perform all the cubicle checks and maintenance items that listed in the *SMCM*, "Circuit Breakers," Subsection 5.IX,
Cubicle checks OK? ✓ Yes _____ No. Maintenance items performed? ✓ Yes _____ No

YT SP

Following service work, check normal all items and systems that were altered during maintenance work, including annunciators and alarms, local and remote control switches, feature and cutout switches, relays, and wires. Check that all the tools and materials have been removed.

*Indicates additional information available in *SMCM*, "Circuit Breakers."

Signed: [redacted] **Date:** 9/20/16

Comments: Document any work performed, conditions found or corrected, and any equipment or schemes added, modified, or removed. Record all the test results. Also record any special tools or equipment required, operational clearance restrictions, and any details that would be useful for planning the next maintenance. Use the back of this sheet or an additional sheet, if necessary.

Reviewed: [signature] **Date:** NOV 28 2016

PG&E Pacific Gas and Electric Company

Circuit Breaker Maintenance Form
Functional-Performance Test

TD-3322M-F13

HEADER DATA LARKIN CB 76

Station Name: ETS.12.12568 CB Number: 40992692 Date: 9-20-16 Order No: 42687218

Manufacturer: GE CB Model: AM13810003H CB Serial Number: 0224A28 35002

Operator Model: ML-13 Test Instrument Make: CAMLIN Model: P3

Functional Performance Test Pass Fail (Check one.)

TESTING AND COUNTER DATA

Distribution-Class Circuit Breaker ☑	Transmission-Class Circuit Breaker ☐
Functional Performance Test (FPT) only ☐	Annual Exercise and FPT ☐
Mechanism Service ☑ Overhaul ☐ As Found ☑ As Left ☐	Mechanism Service ☐ Overhaul ☐ As Found ☐ As Left ☐

Counter Reading Before (As Found) 843 Counter Reading After (As Left) 846

ACTION: Schedule a mechanism service if any of the following conditions are met. Check all that apply:

- ☐ The percentage variation of **trip coil current duration** on this FPT is 15% or greater.
- ☐ The percentage variation between the combination of **trip coil current duration** on this FPT and the previous FPT is 15% or greater.
- ☐ The percentage variation of the **DC close coil current duration** on this FPT is 25% or greater, or the percentage variation between the combination of **DC close coil current duration** on this FPT and the previous FPT is 25% or greater.
- ☐ The greatest DC voltage drop for any operation on this FPT exceeds 10%.
- ☐ An online alarm is received and verified as accurate.
- ☐ The circuit breaker malfunctions during any open or close operations. Any operating malfunction requires a high-priority maintenance plan.
- ☐ A condition assessment indicates problems with the mechanism, poor lubrication, or failure trending.

METHOD 1: Operation of a circuit breaker that has an online circuit breaker monitor with alarm capability.

Did the circuit breaker monitor alarm activate? Yes ☐ No ☐

Actual trip time: ____ ms | Reference trip time setting: ____ ms Alarm time setting: ____ ms

Using the formula below, record the percent trip variation from the baseline operating time: ____ %

$$\frac{\text{Trip Time} - \text{Reference Time Setting}}{\text{Trip Time}} \times 100$$ = The percent trip variation from the base line operating time.

NOTE: If the circuit breaker has operated (as indicated by a counter change) since the previous month's station inspection, and the breaker monitor is not in alarm, notify the local asset strategists who will update SAP to trigger a new FPT date.

METHOD 2: Functional-Performance Test. See the *Substation Maintenance and Construction Manual (SMCM)*, "Circuit Breakers," Section 3, "Diagnostic Tests." TRIP-ACROSS CLOSE-END

First Test	Second Test	Third Test
Trip coil duration ⇨ 47.8 ms	Trip coil duration ⇨ 48.1 ms	Trip coil duration ⇨ 48.4 ms
Close coil duration ⇨ 833.1 ms	Close coil duration ⇨ 828.5 ms	Close coil duration ⇨ 832.3 ms

Largest % variance of the **trip coil duration** times: 1.25 % | Largest % variance of the **close coil duration** times: 0.55 %

Greatest % DC Voltage Drop- Trip: 1.80 % | Greatest % DC Voltage Drop- Close: 21.0 %

$$\frac{\text{Longest test time} - \text{Shortest test time}}{\text{Shortest test time}} \times 100$$ = **Largest Percent Variance** of the trip- and close-coil durations.

$$\frac{\text{Highest DC Voltage} - \text{Lowest DC Voltage}}{\text{Highest DC Voltage}} \times 100$$ = **Greatest DC Voltage Drop** of the control circuit DC Voltage.

ACTION: Attach the P3 or Vanguard printout to this form.

NOTE: For record purposes only, record the close-test times for circuit breakers that have ac closing. Do **not** test rectified ac-to-dc closing.

TRIP Vinit	TRIP Vmin	CLOSE Vinit	CLOSE Vmin
132.7	130.5	132.9	105
132.7	130.4	132.7	104.9
132.8	130.6	132.7	105

Continued on next page

Pacific Gas and Electric Company

Circuit Breaker Maintenance Form
Functional-Performance Test

TD-3322M-F13

TRENDING INFORMATION	Date of baseline "as-left" test (preferred) or previous FPT —
Trip Trending Calculation	**Close Trending Calculation**
Enter the present test trip coil duration times. —	Enter the present test close coil duration times. —
Enter the previous test trip coil duration times. —	Enter the previous test close coil duration times. —
Using the Largest Percent Variance formula from page 1, enter the % variance between the longest and shortest of the six times listed above —	Using the Largest Percent Variance formula from Page 1, enter the % variance between the longest and shortest of the six times listed above —

ACTION: A mechanism service must be performed if: The trip variance as calculated above is +/-15% or more, or the close variance as calculated above is +/- 25% or more, or if the greatest DC voltage drop recorded on this test form exceeds 10%.

Note: Use the operating coil duration from test print-outs for trending. Percent variance may have been done differently on previous tests. When doing the trending calculation, make sure to use the operating coil duration form this test and the previous one.

CHECKS/ASSESSMENT: Perform a condition assessment of the circuit breaker and mechanism. Add comments as necessary.

Lubrication is satisfactory and not abnormally dry, hardened, gummy or excessively contaminated.	Satisfactory ☐ Unsatisfactory ☑
Operations counter and semaphores are working properly	Satisfactory ☑ Unsatisfactory ☐
All indicating lights (red, green, potential indication, etc.) are working properly.	Satisfactory ☑ Unsatisfactory ☐
Verify that the circuit breaker opens and closes properly by remote SCADA operated from the local control center.	Satisfactory ☐ Unsatisfactory ☐ N/A ☑
On ABB Type R-MAG vacuum circuit breakers, clear the breaker and perform a capacitor test (rapid open-close-open) per the "Circuit Breakers" booklet, Section 9, Subsection X.C. **Trip and Close timing tests are not required.**	Satisfactory ☐ Unsatisfactory ☐ N/A ☑

POSSIBLE CAUSES OF ABNORMAL CONDITIONS

Abnormal Condition	Possible Cause
◦ High off-latch time	◦ Poor or incorrect lubrication ◦ Corrosion ◦ Mechanical wear or incorrect mechanical adjustments ◦ Friction in the trip-latch release mechanism Note: Slow operating speed can cause premature wear and failure of the main contacts and interrupters.
◦ Low normal dc voltage supply ◦ Low minimum dc voltage during a CB operation	◦ High-impedance battery cell ◦ Bad wiring, corrosion, or connections ◦ dc ground, partial or hard ground
◦ Abnormal trip-coil current profile curve ◦ Abnormal dc supply-voltage profile curve	◦ Partially shorted trip coil. ◦ Poor trip-circuit continuity caused by loose wire connections, loose fuses, etc. ◦ High-impedance battery cell ◦ dc ground ◦ Faulty "A" contact

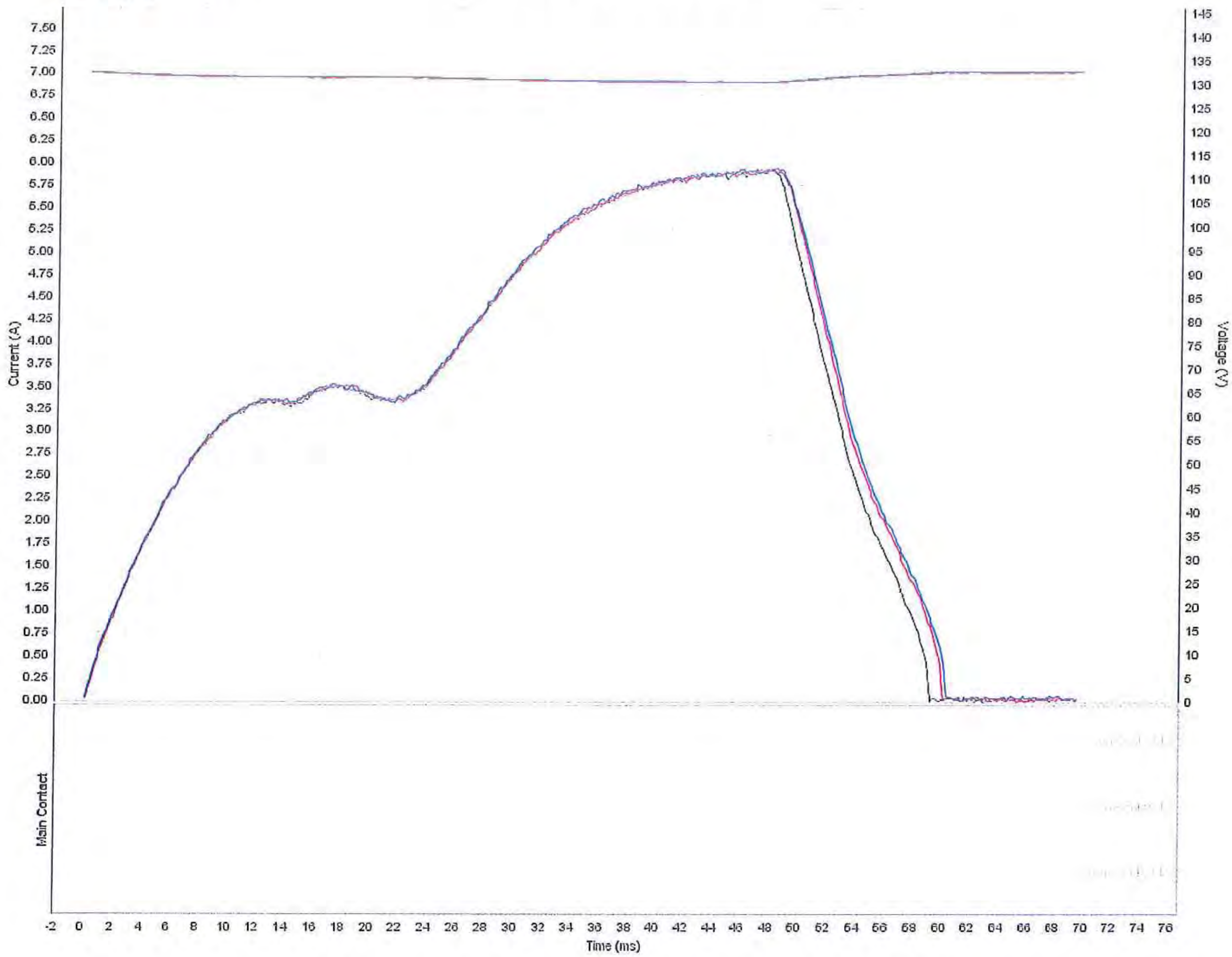
COMMENTS:

Performed By: [redacted] Date: 9/20/16

Reviewed By: [signature] Date: NOV 28 2016

CAMLIN POWER

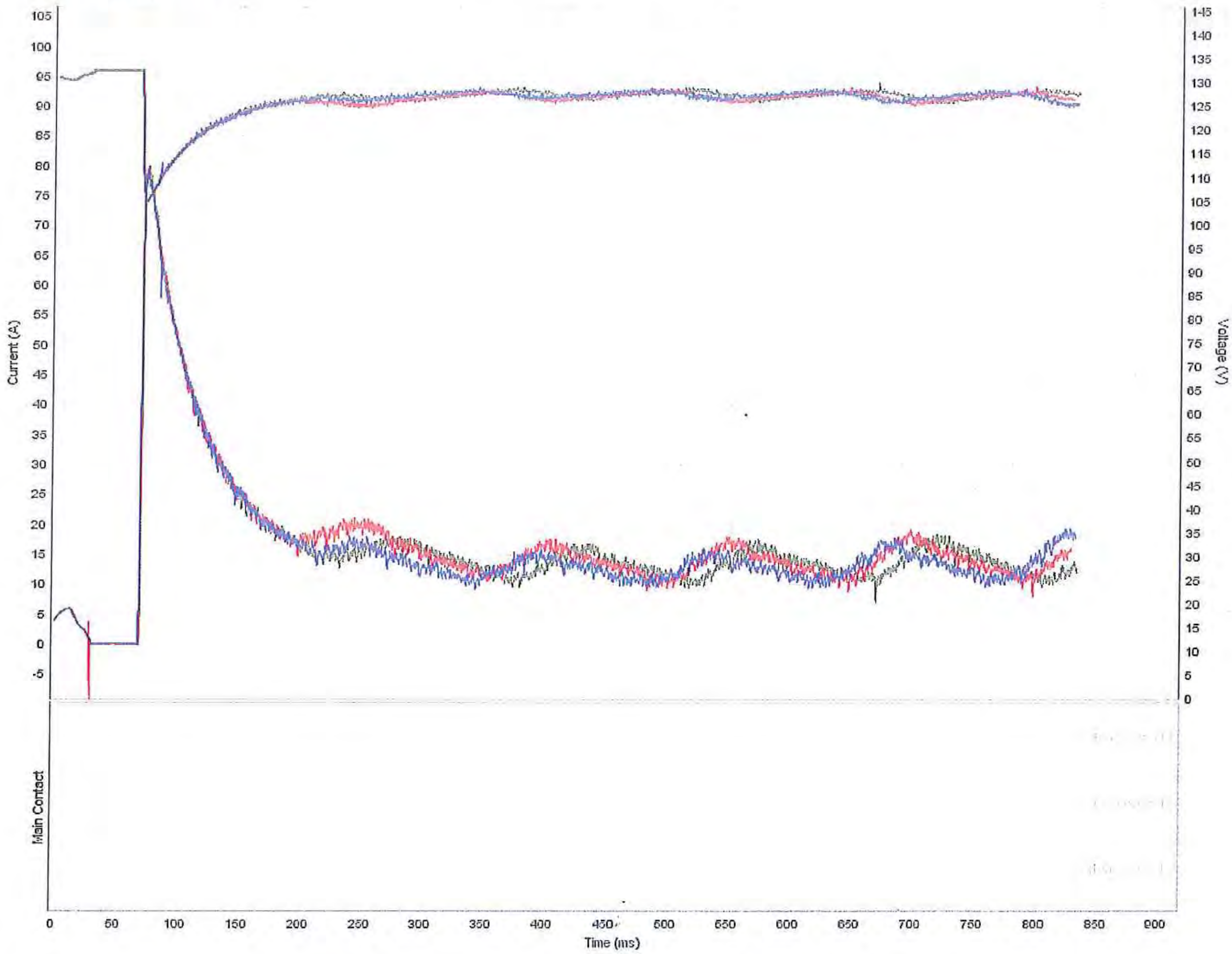
PROFILE RECORD



Rec	Device	Date & Time	Substation	Breaker Identifier	Breaker Type	Latch	Buffer	AuxCon	End	MCon L1	MCon L2	MCon L3	Relay	Vini	Vmin	T
0516	1337 P3	19-Sep-2017 21:09	ETS.12.12568	40992692	AM13810003H	14.69	21.48	48.40	60.39	n/a	n/a	n/a	-1.0	132.80	130.58	Trip
0514	1337 P3	19-Sep-2017 21:07	ETS.12.12568	40992692	AM13810003H	14.38	20.86	48.09	60.16	n/a	n/a	n/a	-1.0	132.69	130.43	Trip
0512	1337 P3	19-Sep-2017 21:05	ETS.12.12568	40992692	AM13810003H	14.22	21.41	47.77	59.22	n/a	n/a	n/a	-1.0	132.72	130.48	Trip

CAMLIN POWER

PROFILE RECORD



Rec	Device	Date & Time	Substation	Breaker Identifier	Breaker Type	Latch	Buffer	AuxCon	End	MCon L1	MCon L2	MCon L3	Relay	Vini	Vmin	T
0515	1337 P3	19-Sep-2017 21:08	ETS.12.12568	40992692	AM13810003H	n/a	n/a	n/a	832.34	n/a	n/a	n/a	-1.0	132.68	105.03	Close
0513	1337 P3	19-Sep-2017 21:06	ETS.12.12568	40992692	AM13810003H	n/a	n/a	n/a	828.52	n/a	n/a	n/a	-1.0	132.75	104.88	Close
0511	1337 P3	19-Sep-2017 21:04	ETS.12.12568	40992692	AM13810003H	n/a	n/a	n/a	833.13	n/a	n/a	n/a	-1.0	132.89	105.00	Close

Pacific Gas and Electric Company

Circuit Breaker Maintenance Form
Functional-Performance Test

TD-3322M-F13

HEADER DATA LARKIN CB 76

Station Name: ETS.12.12568 CB Number: 40992692 Date: 9-20-16 Order No: 42687218

Manufacturer: GE CB Model: AM13810003H CB Serial Number: 0224A28 35002

Operator Model: ML-13 Test Instrument Make: CAMLIN Model: P3

Functional Performance Test Pass Fail (Check one.)

TESTING AND COUNTER DATA

Distribution-Class Circuit Breaker ☑ Functional Performance Test (FPT) only ☐ Mechanism Service ☑ Overhaul ☐ As Found ☐ As Left ☑	Transmission-Class Circuit Breaker ☐ Annual Exercise and FPT ☐ Mechanism Service ☐ Overhaul ☐ As Found ☐ As Left ☐

Counter Reading Before (As Found) 849 Counter Reading After (As Left) 852

ACTION: Schedule a mechanism service if any of the following conditions are met. Check all that apply:

- ☐ The percentage variation of **trip coil current duration** on this FPT is 15% or greater.
- ☐ The percentage variation between the combination of **trip coil current duration** on this FPT and the previous FPT is 15% or greater.
- ☐ The percentage variation of the **DC close coil current duration** on this FPT is 25% or greater, or the percentage variation between the combination of **DC close coil current duration** on this FPT and the previous FPT is 25% or greater.
- ☐ The greatest DC voltage drop for any operation on this FPT exceeds 10%.
- ☐ An online alarm is received and verified as accurate.
- ☐ The circuit breaker malfunctions during any open or close operations. Any operating malfunction requires a high-priority maintenance plan.
- ☐ A condition assessment indicates problems with the mechanism, poor lubrication, or failure trending.

METHOD 1: Operation of a circuit breaker that has an online circuit breaker monitor with alarm capability.

Did the circuit breaker monitor alarm activate? Yes ☐ No ☐

Actual trip time: ____ ms | Reference trip time setting: ____ ms Alarm time setting: ____ ms

Using the formula below, record the percent trip variation from the baseline operating time: ____ %

$$\frac{\text{Trip Time} - \text{Reference Time Setting}}{\text{Trip Time}} \times 100$$ = The percent trip variation from the base line operating time.

NOTE: If the circuit breaker has operated (as indicated by a counter change) since the previous month's station inspection, and the breaker monitor is not in alarm, notify the local asset strategists who will update SAP to trigger a new FPT date.

METHOD 2: Functional-Performance Test. See the *Substation Maintenance and Construction Manual (SMCM)*, "Circuit Breakers," Section 3, "Diagnostic Tests." TRIP - ACONS CLOSE - END

First Test	Second Test	Third Test
Trip coil duration ⇨ 47.6 ms	Trip coil duration ⇨ 47.4 ms	Trip coil duration ⇨ 47.6 ms
Close coil duration ⇨ 825.2 ms	Close coil duration ⇨ 831.6 ms	Close coil duration ⇨ 830.2 ms

Largest % variance of the **trip coil duration** times: 0.42% | Largest % variance of the **close coil duration** times: 0.77 %

Greatest % DC Voltage Drop- Trip: 1.80 % | Greatest % DC Voltage Drop- Close: 21.0 %

$$\frac{\text{Longest test time} - \text{Shortest test time}}{\text{Shortest test time}} \times 100$$ = **Largest Percent Variance** of the trip- and close-coil durations.

$$\frac{\text{Highest DC Voltage} - \text{Lowest DC Voltage}}{\text{Highest DC Voltage}} \times 100$$ = **Greatest DC Voltage Drop** of the control circuit DC Voltage.

ACTION: Attach the P3 or Vanguard printout to this form.

NOTE: For record purposes only, record the close-test times for circuit breakers that have ac closing. Do **not** test rectified ac-to-dc closing.

TRIP Vinit	TRIP Vmin	CLOSE Vinit	CLOSE Vmin
132.6	130.4	132.8	104.9
132.8	130.5	132.6	104.8
132.4	130.4	132.7	104.9

Continued on next page

Pacific Gas and Electric Company

Circuit Breaker Maintenance Form
Functional-Performance Test

TD-3322M-F13

TRENDING INFORMATION	Date of baseline "as-left" test (preferred) or previous FPT —
Trip Trending Calculation	**Close Trending Calculation**
Enter the present test trip coil duration times. —	Enter the present test close coil duration times. —
Enter the previous test trip coil duration times. —	Enter the previous test close coil duration times. —
Using the Largest Percent Variance formula from page 1, enter the % variance between the longest and shortest of the six times listed above —	Using the Largest Percent Variance formula from Page 1, enter the % variance between the longest and shortest of the six times listed above —

ACTION: A mechanism service must be performed if: The trip variance as calculated above is +/-15% or more, or the close variance as calculated above is +/- 25% or more, or if the greatest DC voltage drop recorded on this test form exceeds 10%.

Note: Use the operating coil duration from test print-outs for trending. Percent variance may have been done differently on previous tests. When doing the trending calculation, make sure to use the operating coil duration form this test and the previous one.

CHECKS/ASSESSMENT: Perform a condition assessment of the circuit breaker and mechanism. Add comments as necessary.

Lubrication is satisfactory and not abnormally dry, hardened, gummy or excessively contaminated.	Satisfactory ☑ Unsatisfactory ☐
Operations counter and semaphores are working properly	Satisfactory ☑ Unsatisfactory ☐
All indicating lights (red, green, potential indication, etc.) are working properly.	Satisfactory ☑ Unsatisfactory ☐
Verify that the circuit breaker opens and closes properly by remote SCADA operated from the local control center.	Satisfactory ☐ Unsatisfactory ☐ N/A ☑
On ABB Type R-MAG vacuum circuit breakers, clear the breaker and perform a capacitor test (rapid open-close-open) per the "Circuit Breakers" booklet, Section 9, Subsection X.C. **Trip and Close timing tests are not required.**	Satisfactory ☐ Unsatisfactory ☐ N/A ☑

POSSIBLE CAUSES OF ABNORMAL CONDITIONS

Abnormal Condition	Possible Cause
◦ High off-latch time	◦ Poor or incorrect lubrication ◦ Corrosion ◦ Mechanical wear or incorrect mechanical adjustments ◦ Friction in the trip-latch release mechanism Note: Slow operating speed can cause premature wear and failure of the main contacts and interrupters.
◦ Low normal dc voltage supply ◦ Low minimum dc voltage during a CB operation	◦ High-impedance battery cell ◦ Bad wiring, corrosion, or connections ◦ dc ground, partial or hard ground
◦ Abnormal trip-coil current profile curve ◦ Abnormal dc supply-voltage profile curve	◦ Partially shorted trip coil. ◦ Poor trip-circuit continuity caused by loose wire connections, loose fuses, etc. ◦ High-impedance battery cell ◦ dc ground ◦ Faulty "A" contact

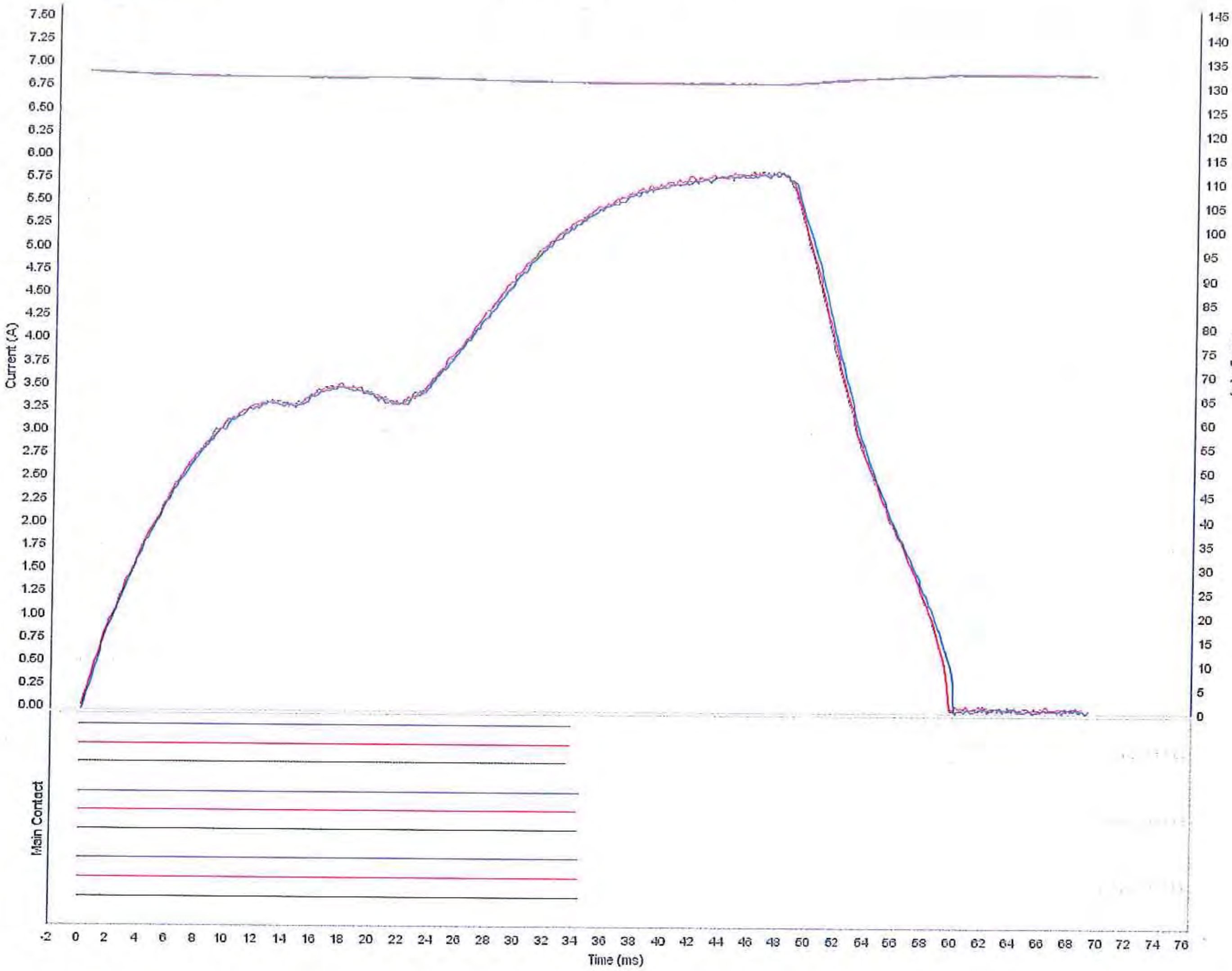
COMMENTS:

Performed By: [redacted] Date: 9/20/16

Reviewed By: Date: NOV 28 2016

CAMLIN POWER

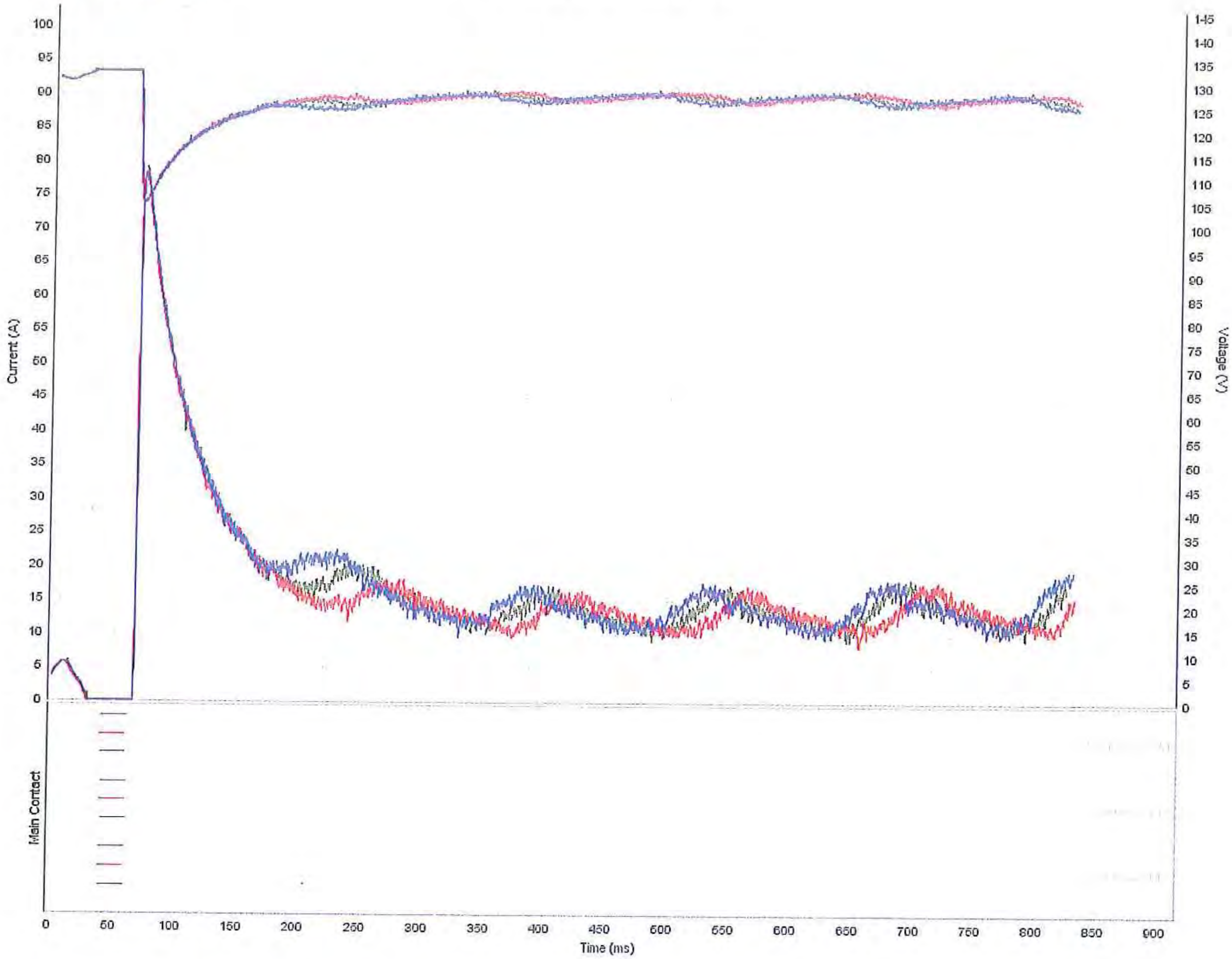
PROFILE RECORD



Rec	Device	Date & Time	Substation	Breaker Identifier	Breaker Type	Latch	Buffer	AuxCon	End	MCon L1	MCon L2	MCon L3	Relay	Vini	Vmin	T
0522	1337 P3	20-Sep-2017 00:41	ETS. 12.12568	40992692	AM13810003H	14.45	22.03	47.62	60.08	33.75	34.38	34.38	-1.0	132.62	130.41	Trip
0520	1337 P3	20-Sep-2017 00:39	ETS. 12.12568	40992692	AM13810003H	n/a	23.28	47.38	59.69	33.67	34.22	34.38	-1.0	132.75	130.55	Trip
0518	1337 P3	20-Sep-2017 00:35	ETS. 12.12568	40992692	AM13810003H	14.30	21.43	47.62	59.69	33.44	34.30	34.45	-1.0	132.64	130.43	Trip

CAMLIN POWER

PROFILE RECORD



Rec	Device	Date & Time	Substation	Breaker Identifier	Breaker Type	Latch	Buffer	AuxCon	End	MCon L1	MCon L2	MCon L3	Relay	Vini	Vmin	T
0521	1337 P3	20-Sep-2017 00:40	ETS.12.12568	40992692	AM13810003H	n/a	n/a	n/a	830.23	41.72	42.11	41.25	-1.0	132.67	104.87	Close
0519	1337 P3	20-Sep-2017 00:37	ETS.12.12568	40992692	AM13810003H	n/a	n/a	n/a	831.64	40.16	40.63	39.77	-1.0	132.65	104.79	Close
0517	1337 P3	20-Sep-2017 00:35	ETS.12.12568	40992692	AM13810003H	n/a	n/a	n/a	825.16	41.33	41.64	40.86	-1.0	132.78	104.88	Close