Pacific Gas and
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PG&E Letter DCL-00-115

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Docket No. 50-275, OL-DPR-80
Diablo Canyon Unit 1
Licensee Event Report 1-2000-004-01
Unit 1 Unusual Event Due to a 12 kV Bus Fault

Dear Commissioners and Staff:

PG&E is submitting the enclosed supplemental licensee event report regarding an Unusual Event due to a 12 kV bus electrical fault.

This event was not risk significant and did not adversely affect the health and safety of the public.

Sincerely,

David H. Oatley

cc: Steven D. Bloom
Ellis W. Merschoff
David L. Proulx
Diablo Distribution
INPO

Enclosure

LMP/2246/N0002112

IE22

# LICENSEE EVENT REPORT (LER)

| FACILITY NAME (1) | DOCKET NUMBER (2) | PAGE (3) |
|---|---|---|
| Diablo Canyon Unit 1 | 0 5 0 0 0 2 7 5 | 1 OF 12 |

TITLE (4)

Unit 1 Unusual Event Due to a 12 kV Bus Fault

| EVENT DATE (5) | | | LER NUMBER (6) | | | REPORT DATE (7) | | | OTHER FACILITIES INVOLVED (8) | |
|---|---|---|---|---|---|---|---|---|---|---|
| MO | DAY | YEAR | YEAR | SEQUENTIAL NUMBER | REVISION NUMBER | MO | DAY | YEAR | FACILITY NAME | DOCKET NUMBER |
| 05 | 15 | 2000 | 2000 | - 0 0 4 - | 0 1 | 08 | 30 | 2000 | | |

| OPERATING MODE (9) | THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11) | | |
|---|---|---|---|
| 1 | X | 10 CFR | 50.73(a)(2)(iv) |
| POWER LEVEL (10) | X | OTHER | Unusual Event |
| 1 0 0 | | | (SPECIFY IN ABSTRACT BELOW AND IN TEXT, NRC FORM 366A) |

LICENSEE CONTACT FOR THIS LER (12)

| NAME | TELEPHONE NUMBER: AREA CODE | |
|---|---|---|
| Roger Russell - Senior Regulatory Services Engineer | 805 | 545-4327 |

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

| CAUSE | SYSTEM | COMPONENT | MANUFACTURER | REPORTABLE TO EPIX | CAUSE | SYSTEM | COMPONENT | MANUFACTURER | REPORTABLE TO EPIX |
|---|---|---|---|---|---|---|---|---|---|
| X | E A | N S B U | G 0 8 0 | N | | | | | |
| | | | | | | | | | |

| SUPPLEMENTAL REPORT EXPECTED (14) | | EXPECTED SUBMISSION DATE (15) | MON | DAY | YR |
|---|---|---|---|---|---|
| [ ] YES (If yes, complete EXPECTED SUBMISSION DATE) | [ x ] NO | | | | |

ABSTRACT (Limit to 1400 spaces. i.e., approximately 15 single-spaced typewritten lines.) (16)


On May 15, 2000, at 0025 PDT, with Unit 1 in Mode 1 (Power Operation) at 100 percent power, Unit 1 experienced a unit trip, followed immediately by a turbine trip and automatic reactor trip.

The cause of the unit trip was an electrical phase-to-phase fault on the 12 kV bus supplied by Auxiliary Transformer 1-1. The 12 kV electrical fault created electrical arcing (fire) which damaged a nearby 4 kV startup bus resulting in loss of both offsite sources of power to all 4 kV loads. All three onsite emergency diesel generators (EDGs) started, and vital loads automatically sequenced onto the EDGs as designed. In response to the fire and loss of both sources of offsite power to vital loads, an Unusual Event (UE) was declared at 0043 PDT.

The onsite fire brigade extinguished the small fire with carbon dioxide. After clearing the room of smoke, the fire was declared out at 0143 PDT. On May 16, 2000, at 0959 PDT, after offsite power was restored and electrical loads were transferred from emergency diesel generators, the UE was terminated. On May 17, 2000, at 2000 PDT, the unit entered Mode 5 (Cold Shutdown).

The cause of the electrical fault could not be conclusively determined but is believed to be associated with long-term degradation, and/or inadequate preventive maintenance (PM) exacerbated by a marginal design. Corrective actions include a new PM program and upgrades to the 4 kV and 12 kV nonsegregated buses on both units.

TEXT

I. <u>Plant Conditions</u>

Unit 1 was in Mode 1 (Power Operation) at 100 percent power.

II. <u>Description of Problem</u>

A. Background

During normal operation, the Unit 1 main generator [EL] supplies 25 kV electrical power to the main transformers [XFMR] (25 kV to 500 kV) that are connected to the PG&E transmission system. The 25 kV system also supplies power to plant loads [EA] fed from Auxiliary Transformer 1-1 (25 kV to 12 kV) and Auxiliary Transformer 1-2 (25 kV to 4 kV). Figure 1 depicts a simplified single line diagram of the Unit 1 power supplies to the 4 kV and 12 kV buses.

The plant auxiliary power systems are designed with voltage, frequency, and over-current protection sensing relays to protect the plant distribution system. Actuation of these protective relays will automatically transfer the power source of the 12 kV and 4 kV buses to separate electrical buses fed from the 230 kV to 12 kV Startup Transformer 1-1 and 12 kV to 4 kV Startup Transformer 1-2.

Class 1E vital loads [EB] are supplied by 4 kV buses F, G, and H, which are normally supplied by Auxiliary Transformer 1-2. Backup offsite power to 4 kV loads is supplied via Startup Transformer 1-2. Each vital bus is also backed up by an emergency diesel generator (EDG) [EK]. In the event that both offsite power sources, auxiliary and startup, are unavailable, 4 kV vital buses F, G, and H have undervoltage relays which start their associated EDG. Vital loads are automatically sequenced onto the EDGs.

Auxiliary and Startup power is carried from the transformers (located outside the turbine building) to the 12 kV and 4 kV switchgear (located in the 12 kV switchgear room of the turbine building) via nonsegregated phase buses [NSBU]. These buses consist of three bus conductors of insulated aluminum or copper in a sealed bus duct enclosure. The conductors are insulated with fiberglass tape, Noryl insulation, or Raychem shrink insulation. Connections consist of silver plated splice plates bolted to the silver plated bus bars. The connections are insulated with polyvinyl chloride (PVC) boots or Raychem tape.

The unit trip [JD] is a non-safety related plant protective feature initiated by sensed plant conditions that require prompt plant shutdown. The unit trip opens the two 500 kV switchyard breakers, opens the main generator field breaker, transfers all

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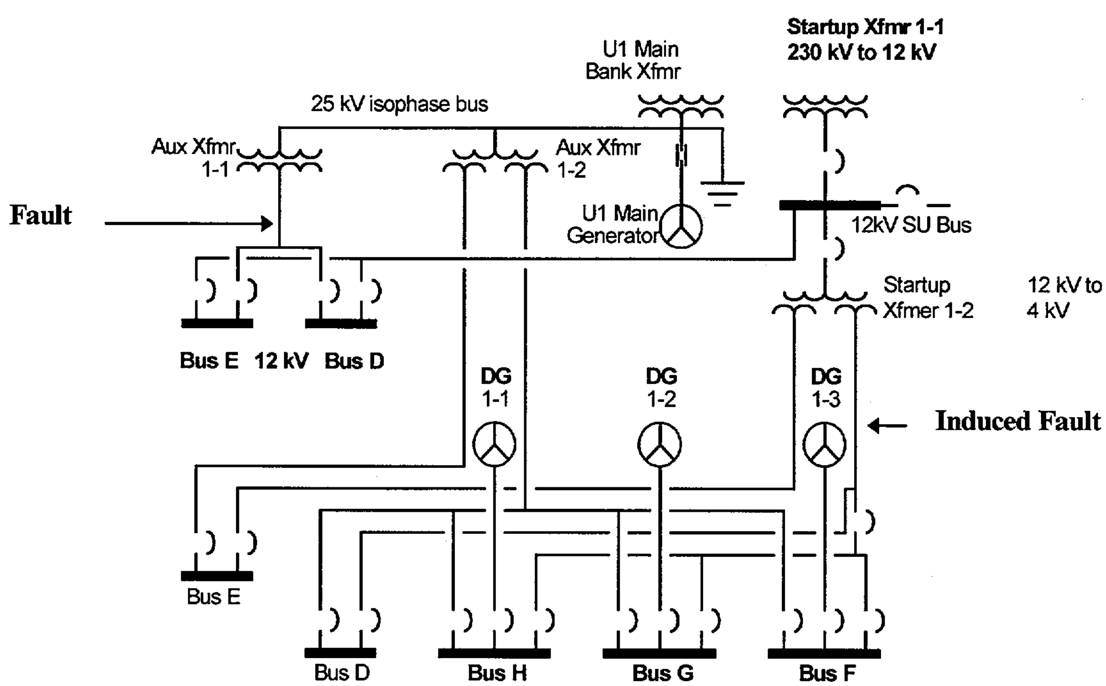
vital and nonvital 4 kV and 12 kV buses to the alternate startup power source, and trips the turbine. A turbine trip provides an anticipatory trip input to the reactor protection system (RPS) [JC] that automatically trips the reactor in anticipation of a sudden loss of load.

The Auxiliary Transformer differential relays [RLY, 87] sense a phase-to-phase electrical fault in the 12 kV bus fed from Auxiliary Transformer 1-1. These relays initiate a unit trip.

The Emergency Plan Table 4.1-1 "Emergency Action Level Classification," for Unusual Events (UEs) includes:

- "Loss of <u>all</u> offsite power for greater than 15 minutes <u>AND</u> at least 2 D/Gs are supplying their vital buses."
- "Fire not under control within 15 minutes of initiating fire fighting efforts <u>AND</u> affecting plant equipment or power supplies in or near the Protected Area(s)."

Figure 1



TEXT

B. Event Description

On May 15, 2000, at 0025 PDT, a phase-to-phase fault occurred on the 12 kV nonsegregated phase bus between Auxiliary Transformer 1-1 and 12 kV bus D and bus E. The fault was immediately sensed by phase differential protective relays which initiated a unit trip. The unit trip caused a turbine trip and automatic reactor trip as designed. Power automatically transferred from Auxiliary to Startup power. Figure 1 shows the location of the fault.

While the unit trip immediately opened 500 kV switchyard breakers and the main generator field breaker, it took several seconds for the voltage to decay from the main generator. Electrical current from the generator continued to feed the fault, resulting in electrical arcing and significant damage to the faulted bus and duct. The fault was in an overhead bus duct inside the 12 kV switchgear room. A 4 kV startup bus duct located immediately above the faulted 12 kV bus was damaged by the fault and subsequent arcing. This damage to the 4 kV bus induced arcing in the 4 kV bus duct resulting in a differential trip of Startup Transformer 1-2, 11 seconds after the initial fault. Figure 1 shows the location of the induced fault. The loss of both auxiliary and startup power to 4 kV vital buses resulted in an undervoltage condition, causing EDGs to start. Vital loads on 4 kV buses F, G, and H, automatically sequenced onto their associated EDGs.

Startup Transformer 1-1 remained energized supplying power to nonvital 12 kV loads, consisting of the 4 reactor coolant pumps (RCPs) and one circulating water pump (CWP). The faults left nonvital 4 kV buses D and E deenergized.

On May 15, 2000, at 0043 PDT, the shift manager declared an UE due to the fire lasting greater than 15 minutes and loss of both sources of offsite power. All notifications required by the UE were completed on time, including updates throughout the 33 hours the unit remained in a UE.

The onsite fire brigade requested offsite assistance as a precautionary measure. After electrical current to the fault diminished, the arcing ceased and only a small fire remained. When the fire brigade entered the room, they quickly extinguished the fire with a $CO_2$ extinguisher, before offsite assistance arrived. After clearing smoke from the room, the fire was declared out at 0143 PDT.

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On May 15, 2000, at 0400 PDT, an Event Response Plan (ERP) meeting was held in which the vice president and plant manager assigned the engineering services manager to head the event response team to lead recovery and investigation efforts. Sub-teams were assigned to:

1. Recover offsite power to vital loads;
2. Investigate the cause of the fault; and
3. Restore the damaged equipment.

After evaluation of the damage, time required for repair and applicable technical specifications, management decided the unit would be taken from Mode 3 (Hot Standby) to Mode 5 (Cold Shutdown), after satisfying chemistry and radiation protection (RP) considerations. The ERP manager also assigned an engineer and an operator to perform augmented monitoring of the EDG's. Subsequent meetings emphasized the precautions to be taken while offsite power was unavailable.

On May 16, 2000, at 0959 PDT, after offsite power was restored to the vital and nonvital 4 kV loads, and the EDGs were secured, the UE was terminated.

On May 17, 2000, at 2000 PDT, the unit entered Mode 5.

C. Inoperable Structures, Components, or Systems that Contributed to the Event

None.

D. Other Systems or Secondary Functions Affected

EDG 1-2 autostarted during the initial transfer from auxiliary power to startup power. While this was not the expected response, it is conservative in that the EDG starts early. A review of the voltage traces and as-found relay settings confirmed there were no malfunctions. When startup power was lost, loads sequenced onto EDG 1-2 as designed.

A steam generator (SG) safety valve [RV] lifted during the transient, within 2 percent of its setpoint. After operators lowered steam pressure, the valve reseated.

The loss of nonvital 4 kV power forced several systems to use their battery backup power, including the switchyard instruments and controls

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[FK]. As a precautionary measure, a portable generator was placed in the switchyard to maintain the batteries.

The loss of nonvital 4 kV power resulted in loss of AC power to several important pieces of nonvital equipment, including:

- turbine building sumps,
- generator air-side seal oil pump,
- $CO_2$ compressor,
- main feed pump AC bearing oil pumps,
- auxiliary building sump pumps,
- miscellaneous equipment drain tank (MEDT) pump,
- plant process computer inverter,
- the clearance coordinator's office,
- the shift technical advisor's office; and
- the secondary chemistry laboratory.

Temporary plant jumpers were issued by engineering to maintain power supplies to selected nonvital equipment and to assist in extending station battery capacity.

While depressurizing the reactor coolant system (RCS) [AB], operators prematurely restored power to the accumulator block valves while the RCS was still above 1000 psig, thus violating a technical specification requirement. For more details, refer to LER 1-00-005-00.

E. Method of Discovery

There were no personnel in the room at the time of the fault. A security guard located near the main bank transformers heard arcing noise from the fault, saw smoke coming from the vicinity of Auxiliary Transformer 1-1, and called the control room to report the general location of the fire. A roving fire watch who had recently exited the room, heard the noise, saw the smoke and called in the fire alarm to the control room, noting that the smoke was coming out of the 12 kV switchgear room louvers. Another security guard opened the door to the 12 kV switchgear room without entering and confirmed the location of the fire. Security guards assisted the fire brigade by unlocking doors to allow unrestricted access to the fire.

TEXT

Operators recognized a significant electrical fault had occurred by the unit trip and various annunciators, including the smoke detectors alarming from the 12 kV switchgear room.

F. Operator Actions

Operators gained control of RCS cooldown early in the transient by throttling auxiliary feedwater (AFW) [BA] flow and transferring pressurizer heaters to their vital backup power supply. Minimum RCS pressure remained more than 100 psi above the safety injection setpoint.

After the initial notifications, senior reactor operator (SRO) trained personnel made the required ongoing notifications to County, State and the NRC, including keeping the NRC bridge line open for the duration of the UE. The information communicated was generally accurate and timely. Operators initially reported a transformer explosion, and a failed open SG safety valve. These initial reports were not corrected as soon as they could have been in the ongoing updates with the NRC.

Operators recognized that the loss of nonvital 4 kV resulted in a loss of cooling to the running CWP and appropriately decided to secure the CWP before it overheated.

Operators diagnosed that a SG safety valve lifted and did not fully reseat, causing a decrease in SG level. Following procedures, operators manually lowered the SG pressure, allowing the safety valve to reseat.

Operators detected a significant and rapid decrease in condensate storage tank (CST) level and took manual action to close the condenser hotwell makeup valve which failed open (as designed) on the loss of power.

G. Safety System Responses

The engineered safety features actuation system (ESFAS) [JE] responded as designed. As mentioned previously, the unit trip resulted in an automatic reactor trip. All three EDGs started and their vital loads were sequenced on. All three AFW pumps autostarted. Also, when the CWP was secured, operators closed the main steam isolation valves (MSIVs).

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## III. Cause of the Problem

### A. Immediate Cause

The cause of the bus failure could not be conclusively determined due to the absence of physical evidence. The bus connection that failed was vaporized or melted. Several feet of conductor had burned or melted away. In order to perform an investigation, the fault location was quarantined. Detailed evidence was gathered prior to cleanup. Potential causes that were considered and eliminated include: maintenance activities, testing, sabotage, foreign material or animal, and insulation cracking.

The immediate cause is postulated to be a thermal failure of the bolted connection of the center conductor of the 12 kV bus supplied by Auxiliary Transformer 1-1. The PVC boot failed due to the excessive heat and created smoke. The radiant heat from the center conductor caused the insulation to fail on adjacent conductors. The smoke provided an ionized environment for a phase-to-phase arc from the center conductor to the south conductor. Subsequently, there was arcing between all conductors.

### B. Root Cause

The root cause of the thermal failure of the bolted connection could not be conclusively determined. Potential causes include:

1. Long-term degradation - loosening due to creep, or corrosion possibly assisted by PVC boot degradation,
2. Inadequate design relative to the normal heavy load which includes 6 large motors (2 CWPs and 4 RCPs),
3. Inconsistent silvering of splice plates,
4. Previous events:
    - Auxiliary Transformer 1-1 faulted through this bus in 1995 (LER 1-95-014-00).
    - A 12 kV bus connection failed in a fuse box (fault current was not through this bus).

C. Contributory Cause

Factors which made the consequences of the initial fault more significant include:

1. The fault occurred in a section of the bus that was connected directly to the main generator which continued to feed the fault after the unit trip, thus causing more damage.
2. The fault occurred on a connection in close proximity to the 4 kV startup bus duct, and induced a second fault. The loss of both sources of offsite power made the event more safety significant.

## IV. Assessment of the Safety Consequences

The fault resulted in a Loss of External Load and Turbine Trip which is a previously analyzed Final Safety Analysis Report Update, Chapter 15.2.7, Condition II event. Forced circulation was maintained while both sources of offsite power to vital buses were lost while in Mode 3. All safety systems functioned as designed, thus the event was concluded to be not safety significant.

The condition was not evaluated using the NRC's Significance Determination Process (SDP) because it involved a performance indicator and therefore does not require SDP screening.

The event involved a loss of both sources of offsite power to 4 kV vital buses, and a reactor trip with a loss of normal heat sink. A probabilistic risk assessment was performed which concluded the actual increased core damage frequency (CDF) for this 33 hour event was 3.6E-7. Thus, the event was not risk significant and did not adversely affect the health and safety of the public.

The event did not involve a Safety System Functional Failure.

The event is being reported as a “Scram with a loss of normal heat removal” in accordance with NEI 99-02, “Regulatory Assessment Performance Indicator Guideline.”

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V. <u>Corrective Actions</u>

A. Immediate Corrective Actions

On May 16, 2000, at approximately 0806 PDT, Auxiliary Transformer 1-2 was reenergized, restoring offsite power to 4 kV buses. Maintenance personnel had removed 25 kV bus links to isolate Auxiliary Transformer 1-1 and allow reenergizing Auxiliary Transformer 1-2 by backfeeding from the 500 kV switchyard. While this action may have been able to be accomplished more quickly, personnel safety was paramount during restoration. The 12 kV startup power kept much of the 12 kV equipment energized which contributed to the personnel risk during the restoration activities. Also, due to the fault, fire, and associated smoke, the extent of possible equipment damage had to be evaluated and maintenance performed prior to reenergizing equipment.

Engineering evaluated the 12 kV auxiliary bus on Unit 2 and concluded it was less susceptible due to major maintenance in 1996, when all the connections were disassembled, resilvered, and retorqued.

Prior to returning Unit 1 to service, extensive inspections, tests, maintenance and repairs were performed, including:

1. To increase the capacity, the 12 kV aluminum bus inside the turbine building was replaced with copper, from where the bus entered, to past the damaged section;
2. Belleville washers were added at bolted connections to help maintain torque on connections;
3. Two splice plates were installed in connections where only one was used originally;
4. The 12 kV bus, from Auxiliary Transformer 1-1 to the bus D and E breaker cubicles was cleaned. Each connection was micro-ohm and torque checked;
5. The damaged section of the 4 kV bus was refurbished;
6. The remaining 4 kV bus in the switchgear room was, visually inspected and cleaned. Each connection was micro-ohm and torque checked.
7. Switchgear panels in the room were inspected and tested, damaged equipment was replaced, and all cabinets were cleaned inside and out.

8. Auxiliary Transformer 1-1 and Startup Transformer 1-2 had the oil analyzed, relays checked, and a power factor test performed;
9. 12 kV D and E switchgear PM's were performed;
10. Hipot tests were performed on each section of bus prior to reenergizing;
11. Phase rotation was verified.

B. Corrective Actions to Prevent Recurrence

Both units' 12 kV and 4 kV nonsegregated buses will be upgraded to preclude similar events. These upgrades include:

1. All the bolted bus joints will be inspected, retorqued, and new insulating boots will be installed.
2. Busses with little design margin will be upgraded from aluminum to copper, and large copper splice plates will be installed in select locations.
3. A preventive maintenance program will be implemented for these nonsegregated buses.

VI. <u>Additional Information</u>

A. Failed Components

The failed component was a 12 kV aluminum bus bar connection manufactured by General Electric. The connection was covered by a PVC insulating boot. The connection and boot were installed over 20 years ago, and no maintenance has been performed on them since. In 1995, the boot was removed, the connection was visibly inspected and the boot reinstalled.

B. Previous Similar Events

LER 1-95-014-00, "Diesel Generators Started and Loaded as Designed Upon Failure of Auxiliary Transformer 1-1 Due to Inadequate/Ineffective Procedures Related to the Control of Grounding Devices." A UE was declared during the refueling outage due to the transformer fire and loss of all offsite power. Auxiliary Transformer 1-1 failed when the 12 kV bus was reenergized after maintenance, but before the grounding device

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(ground buggy) was removed from a 12 kV breaker cubicle. Relevant corrective actions included inspecting the 12 kV buses from the transformer to the turbine building, and repairing any damage. Also, the 12 kV bus D and E breaker cubicles were inspected, with no repair necessary.

On April 23, 1996, while inspecting the Unit 2 12 kV auxiliary buses, cracked Noryl insulation was discovered. The buses were reinsulated using Raychem shrink insulation. The connections were disassembled, resilvered, reassembled to specified torque. Based on this maintenance work, Unit 2 is believed to be less susceptible to a similar fault.

LER 1-96-017-00, "Automatic Reactor Trip Due to a 12 kV Electrical Fault." The cause of the fault was determined to be degradation of the 12 kV electrical bus PVC boot. The PVC degradation produced a corrosive environment that led to an electrical fault. Immediate corrective action included replacing all suspect PVC boots with Raychem tape for Unit 1 and evaluation of the 4 kV and 12 kV bus ducts for Unit 2. Corrective actions to prevent recurrence included a detailed inspection of all 4 kV and 12 kV bus ducts for similar degradation of PVC boots.