UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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January 12, 2006

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Dear Mr. Keenan:

SUBJECT: NRC INSPECTION REPORT 05000275\2005002 and 05000323\2005002

Because of an error in documenting the completed inspection scope for the ALARA inspection conducted January 10-14, 2005, insert the enclosure to this letter as replacements for pages 14 - 21 of NRC Inspection Report 05000275/2005002 and 05000323/2005002.

Please accept my apology for any inconvenience these actions may have caused.

Sincerely,

//RA//

Michael P. Shannon, Chief
Plant Support Branch
Division of Reactor Safety

Dockets: 50-275
50-323
Licenses: DPR-80
DPR-82

Enclosure:
Pages 14 - 21 of NRC Inspection Report 05000275\2005002 and 05000323\2005002

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SUNSI Review Completed: ___Yes___ ADAMS: / Yes ☐ No Initials: _GLG_
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a. Inspection Scope

The inspectors reviewed one temporary plant modification during this inspection period to verify that it did not affect safety system functions. Temporary plant modifications may include jumpers, lifted leads, temporary systems, repairs, design modifications, and procedure changes which can introduce changes to plant design or operations. As part of the inspection effort, the inspectors verified aspects of the temporary plant modification that include energy requirements, material compatibility, structural integrity, environmental qualification, code and safety classification, system timing constraints, reliability, cooling requirements, control signals, equipment protection boundaries, water flow paths, pressure boundary integrity, procedures, drawings, and tests. During this inspection period, the following temporary plant modifications were reviewed:

- (Unit 1) Temporary ultrasonic level indicator on Line 4296 (AR A0612988)

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 ALARA Planning and Controls (71121.02)

The inspectors completed 8 samples of ALARA planning and controls.

a. Inspection Scope

The inspectors assessed PG&E's performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20 and PG&E's procedures required by Technical Specifications as criteria for determining compliance. The inspectors interviewed PG&E personnel and reviewed:

- Five work activities from previous work history data which resulted in the highest personnel collective exposures
- Site specific trends in collective exposures, plant historical data, and source-term measurements
- Assumptions and basis for the current annual collective exposure estimate, the methodology for estimating work activity exposures, the intended dose outcome, and the accuracy of dose rate and man-hour estimates

- Method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered

- Records detailing the historical trends and current status of tracked plant source terms and contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry

- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas

- Self-assessments, audits, and special reports related to the ALARA program since the last inspection

- Effectiveness of self-assessment activities with respect to identifying and addressing repetitive deficiencies or significant individual deficiencies

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA3 Event Followup (71153)

.1 (Closed) License Event Report (LER) 50-323/2003-004-001: Manual Reactor Trip Due to a Random Fuse Failure.

On March 17, 2003, with Unit 2 in Mode 3 (Hot Standby) operators initiated an manual reactor trip in accordance with plant procedures. During control rod testing of Control Bank B, operators noticed a difference of greater than 12 steps between demanded position and the Digital Rod Position Indication for Control Bank B. PG&E determined that a single random fuse failure for the moveable coil circuitry prevented rod F2 from movement with the associated Control Bank B demand. Operators correctly initiated a reactor trip in accordance with plant procedures.

The inspectors reviewed this LER and determined that no violations of NRC requirements occurred and that the LER provided adequate description and corrective actions for the event. This LER is closed.

.2 (Closed) LER 50-323/2003-005-00 and -01: Technical Specification Required Shutdown due to Personnel Error.

On April 4, 2003, a Technical Specification 3.7.5.C required shutdown was initiated because an Auxiliary Feedwater System check valve was installed backwards. This issue was discussed in detail in NRC Inspection Report 50-275; 323/2003-06. A Green NCV was identified.

The inspectors reviewed this LER and determined that no new information was provided that would change the original disposition. This LER (and subsequent Revision 01) is closed.

4OA4 Other Crosscutting Aspects of Findings

Section 1R04.2 identified a human performance aspect for failure to pre-plan maintenance associated with the CRVS that resulted in the control room boundary being opened without administrative controls.

Section 1R05.2 identified a problem identification and resolution crosscutting aspect for failure to correct operations responder training deficiencies.

Section 1R14.1 identified a human performance crosscutting aspect for failing to follow procedures when removing a stator cooling water-heat exchanger from service.

Section 4OA5.1 identified a problem identification and resolution crosscutting aspect associated with operations and engineering personnel not recognizing the significance of the degraded condition and not implementing timely corrective actions.

4OA5 Other

.1 (Closed) Unresolved Item (URI) 05000323/2004005-06: Failure to Promptly Correct Diesel Engine Generator Lube Oil Instrument Line Crack.

Introduction. The inspectors identified a Green NCV for the failure to promptly correct a cracked lube oil instrument sensing line, as required by 10 CFR Part 50, Appendix B, Criterion XVI. As a result, there was an increased potential for DEG 2-3 to trip on low lube oil level.

Description. On August 29, 2004, operators discovered a lube oil leak coming from the welded connection of Valve DEG-2-1084 to the downstream 3/8 inch instrument line. The instrument line connected the lube oil system to pressure Switch PS-237. The pressure switch provided a low pressure alarm for the pre-circulation lube oil pump. PG&E decided to correct the leak in the next available maintenance outage window, which would be in Refueling Outage 2R12. Additionally, as documented in AR A0617419, engineering personnel did not consider the leak to affect the operability of DEG 2-3 and no formal prompt operability assessment was performed at that time.

Following the Parkfield earthquake on September 28, 2004, operators initiated a test run of the Unit 1 and 2 DEGs to verify their capability start and run. During the pre-firing checks for DEG 2-3, it was noted that the oil leak had grown significantly (approximately 12 drops per minute). Following discussions between operations, maintenance, and engineering personnel, DEG 2-3 was declared inoperable. Operators subsequently closed Valve DEG 2-1084, which isolated the leak. Diesel engine Generator 2-3 was again considered operable under a prompt operability assessment documented in AR A0617419. The cracked instrument line was replaced on October 2, 2004.

PG&E personnel performed a failure analysis of the cracked tubing and determined that the crack initiated at the toe of the weld and was the result of high-cycle fatigue. The crack was circumferential at the toe of the weld, and was through-wall for half of the tubing's outer diameter. The source of the stress that created the crack was the unsecured mass of Valve DEG-2-1084 and vibration from the pre-circulation lube oil pump at standby and the DEG when it was in operation. PG&E personnel evaluated the crack and determined that it would have minor impact on DEG 2-3 operation. This evaluation was based on the estimated force to completely break the cracked tubing (30 to 40 pounds) and the calculated leakrate at an operating lube oil pressure of 90 psig, as compared to a standby lube oil pressure of 15 psig. Engineers calculated the leakrate to be 0.0015 gph at a lube oil pressure of 90 psig. Based on this leakrate, and the lube oil low level alarm setpoint of 110 gallons, engineers estimated 107,000 hours of operation before the alarm would activate.

The inspectors performed an independent evaluation of the cracked tubing's impact on DEG 2-3. Since DEG 2-3 only operated approximately 2 hours between the time the leak was discovered and the time DEG 2-3 was declared inoperable, the inspectors observed that the crack had propagated quickly; primarily from the vibration of the pre-circulation lube oil pump only. The inspectors surmised that there was an increased probability that the instrument tube would completely severe under several hours of DEG 2-3 operation. The inspectors, and PG&E personnel, calculated that if the tubing severed, and was not obstructed, then the leakrate would become 10 to 15 gpm. However, based on the mounting of the tubing it was determined that if the tubing were to completely severe, the flow out of Valve DEG-2-1084 would be obstructed by instrument tubing and the resulting flow would be 1 to 3 gpm. PG&E estimated that DEG 2-3 could sustain a loss of 200 gallons of lube oil before damage to the engine began and/or the engine shutdown on low-low lube oil pressure. The low lube oil level alarm would become active after DEG 2-3 lost 170 gallons of lube oil. Assuming no operator intervention before the low lube oil level alarm became active, operators would have 10 to 30 minutes to respond to DEG 2-3 and isolate Valve DEG-2-1084. The inspectors determined that operators would be able to respond to such a scenario in a timely manner to prevent damage to DEG 2-3.

A problem identification and resolution crosscutting aspect associated with operations and engineering personnel not recognizing the significance of the degraded condition and implementing timely corrective actions.

<u>Analysis</u>. The performance deficiency associated with this event is the failure to correct a cracked lube oil instrument tubing downstream of Valve DEG-2-1084. This deficiency impacted the mitigating systems cornerstone for reliability of systems that respond to initiating events to prevent undesirable consequences and affects the equipment performance attribute. The finding was more than minor using Example 4.f of Inspection Manual Chapter 0612, Appendix E. Similar to Example 4.f, the inspectors

determined that there was impact to DEG 2-3 operability. Using the SDP Phase 1 screening worksheets in Appendix A of Inspection Manual Chapter 0609, the finding was determined to be potentially greater than very low safety significance because the failure could have resulted in an actual loss of safety function of DEG 2-3.

An NRC Senior Reactor Analyst performed a Phase 3 significance determination. The following assumptions were made:

- A bounding assumption was made that DEG 2-3 would have failed to run at all times between August 29 and September 28, 2004 (exposure period = 30 days), absent operator recovery actions, as a result of lubricating oil depletion following failure of the degraded weld. The weld failure was assumed to occur at the start of DEG 2-3 due to engine vibration.

C The postulated failure of DEG 2-3 to run is considered to be an independent failure mechanism, not to impact the other two DEGs.

C A fire would not have occurred in conjunction with the postulated oil spill. The location of the oil leak was not close to any hot surfaces and would not have been expected to create a fire.

C A bounding assumption was made that operators would fail to detect the leak for the one-hour period before the low level alarm activates and that irrecoverable engine damage would occur if the diesel engine was not shut down within 10 minutes. In reality, it is likely that the leak would be detected prior to the alarm.

C Using the worst-case flowrate of 3 gpm, as calculated by the resident inspectors, the low level alarm would activate approximately 57 minutes after engine start. Operators would have 10 minutes to isolate the cracked instrument tubing line based on 30 gallons margin between the low level alarm and a diesel engine shutdown on the low lube oil pressure. It is presumed that the engine would shutdown automatically on low lube oil pressure, or operators would need to shut down the engine manually in order to isolate the instrument line due to the presence of hot spewing oil. In the latter case, operators would also have to de-energize the pre-circulating lube oil pump to prevent the hot lube oil from spewing in the vicinity of the isolation valve. The pre-circulating lube oil pump can be de-energized locally and operators are knowledgeable regarding this expected action.

Calculation

Using the SPAR-H Human Reliability Analysis Method (INEEL/EXT-02-01307), the total estimated failure probability for operators to diagnose the problem and then take all actions necessary to restore the function of the diesel generator was 0.42.

The Diablo Canyon SPAR model, Revision 3.11 was used to estimate the change in risk resulting from the performance deficiency. In this model, the nominal value assigned to the failure of DEG 2-3 to run is 2.117E-2. To account for the performance deficiency, the analyst added to this value the probability associated with failure to isolate the postulated worst-case oil leak. Therefore, the new probability of DEG 2-3 failing to run was set to 2.117E-2 + 0.42= 0.44.

The SPAR model result was a Î-CDF of 1.433E-6/yr. The analyst verified that all cutsets contributing to this figure were associated with LOOP sequences and that the distribution of risk within the various sequences was within expectations. With an exposure period of 30 days, the impact on risk of the performance deficiency is estimated as a Î-CDF of 1.433E-6/yr. (30 days exposure/yr./365 calendar days/yr.) = 1.2E-7/yr.

<u>External Events</u>

The analyst was aware that Diablo Canyon lies in an active seismic area and that an earthquake could result in a concurrent loss of offsite power and failure of the flawed instrument tubing welded connection. It was determined by the analyst that the subject welded connection would not be particularly susceptible to a failure mode specific to seismic loadings because of the skid-mounted configuration (everything moves as a unit and little sheer stress would be applied to the cracked weld). Therefore, the risk contribution from seismic events for this finding is primarily a function of the increased frequency of loss of offsite power events.

The analyst determined that the frequency of seismic events that cause a loss of offsite power without also causing a loss of diesel generators is 1.07E-3/yr. The analyst ran two cases in the SPAR model to determine the contribution of seismic initiating events to the risk significance of the performance deficiency. In the first case, the LOOP initiating frequency was set to 1.07E-3/yr, as stated above. All operator recovery of offsite power basic events was set to TRUE (because recovery of offsite power would not be expected prior to postulated core damage). The result in SPAR was 4.41E-6/yr. In the second case, all of the changes above were made in addition to raising the fail-to-run of DEG 2-3 to 0.44 and adjusting the common cause failure to its nominal value, as was done in the internal events analysis. The result was 4.611E-6/yr. The difference between these two values is 2.0E-7/yr. Taking into account the exposure period of the finding, the estimated risk contribution from seismic events is 1.6E-8/yr.

Other external initiating events were determined not to be significant when compared to the loss-of-offsite power event frequency as used in the SPAR model (3.3E-2/yr.), or they were already included in the SPAR model frequency. These initiating events include fire-induced loss-of-offsite power and severe weather.

Based on the above considerations, the analyst concluded that the contribution from external initiators would not be sufficient to change the risk characterization of the finding.

Large Early Release Frequency:

The analyst determined that the finding required assessment of large early release because the Phase 3 result provided a risk significance estimation of greater than 1×10^{-7}. All of the sequences contributing to a change in risk from the base case are LOOP sequences that involve, in some cases, a station blackout. Diablo Canyon has a large, dry containment structure. Using Manual Chapter 0609, Appendix H, Table 5.1, "Phase 1 Screening Type A Findings at Power," the analyst concluded that none of the sequences of interest contributed to the risk of a large early release.
Based on the resulting conditional core damage probability of 1.2E-7/yr., the finding was determined to be of very low safety significance.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformance are promptly identified and corrected. Contrary to the above, PG&E failed to promptly correct the cracked lube oil instrument tubing on DEG 2-3. Specifically, PG&E observed the crack, but did not adequately assess the growth rate of the crack or its potential impact on DEG 2-3 operability. Because this failure to promptly correct the lube oil instrument tubing is of very low safety significance and has been entered into the corrective action system as AR A0617419, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/05-02-04, Failure to Promptly Correct Diesel Engine Generator Lube Oil Instrument Line Crack.

40A6 Management Meetings

Exit Meeting Summary

The resident inspection results were presented on April 15, 2005, to Mr. James Becker, Vice President and Station Director, and other members of PG&E management. PG&E acknowledged the findings presented.

The inspectors asked PG&E whether any materials examined during the inspection should be considered proprietary. Proprietary information was reviewed by the inspectors and left with PG&E at the end of the inspection.

4OA7 Licensee Identified Violations

The following finding of very low safety significance was identified by PG&E as a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- Technical Specification 5.4.1 requires, procedures be established, implemented, and maintained covering access control to radiation areas including a radiation work permit system. Station procedure RP1.ID9, "Radiation Work Permits," Revision 7, Section 4.3, required individuals signing in on a radiation work permit to be responsible for reading, understanding, and following the applicable requirements. On November 18, 2004, PG&E identified that a crew tasked to install steam generator inserts and manways on the 2-2 Steam Generator failed to get permission prior to entering the steam generator platform and prior to removing the cold leg shield door. Radiation Work Permit 04-2041 required radiation protection be contacted prior to moving or adjusting shielding. The finding was documented in the corrective action program as AR-0624425. The finding was found to have very low safety significance because it was not an ALARA finding, there was no overexposure or substantial potential for an overexposure and the ability to assess dose was not compromised.

ATTACHMENT: SUPPLEMENTAL INFORMATION