UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

February 29, 2008

EA-08-028

Mike Blevins, Senior Vice President
and Chief Nuclear Officer
Luminant Generation Company, LLC
ATTN: Regulatory Affairs
Comanche Peak Steam Electric Station
P.O. Box 1002
Glen Rose, TX 76043

SUBJECT: FINAL SIGNIFICANCE DETERMINATION FOR A WHITE FINDING AND NOTICE OF VIOLATION - COMANCHE PEAK STEAM ELECTRIC STATION - NRC SPECIAL INSPECTION REPORT 05000445/2007008

Dear Mr. Blevins:

On January 24, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed its reviews related to a Special Inspection at your Comanche Peak Steam Electric Station, Unit 1, facility. This Special Inspection Team was chartered to review the circumstances related to the failure of Emergency Diesel Generator (EDG) 1-02 to start on November 21, 2007, and to evaluate the actions taken in response to the problem. The NRC's initial evaluation satisfied the criteria in NRC Management Directive 8.3, “NRC Incident Investigation Program,” for conducting a special inspection. The possibility that adverse generic implications were associated with the EDG failure mechanism was the deterministic criterion met. Additionally, the result of the NRC’s initial conditional risk assessment associated with this degraded condition indicated that a special inspection was warranted. The determination that the inspection would be conducted was made by the NRC on November 30, 2007, and the inspection started on December 4, 2007.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission’s rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The enclosed inspection report documents the inspection results, which were discussed on December 7, 2007, and again on January 10, 2008, with Mr. R. Flores and Mr. T. Hope, respectively, and other members of your staff. On January 24, 2008, an exit meeting was held with Mr. F. Madden, Director, Regulatory Affairs, and other members of your staff to convey the final disposition of the inspection findings. Following a discussion of the preliminary safety significance of this finding during the exit briefing, Mr. Madden indicated that Luminant Power does not contest the characterization of the risk significance of this finding, and that you have declined to further discuss this issue at a Regulatory Conference or provide a written response. Accordingly, the NRC is issuing the final significance determination for the inspection finding as discussed below. On February 25, 2008, an additional exit meeting was held with Mr. T. Hope, and other members of your staff to convey a revision to one of the inspection findings.

This report documents one finding concerning a failure to satisfy Technical Specification (TS) Limiting Condition for Operation (LCO) 3.8.1 due to EDG 1-02 being in an inoperable condition following maintenance. Following the discovery of this condition, the TS required actions were satisfied however, the time period between the occurrence of the condition and the discovery of the condition exceeded the TS allowed outage time for the EDG. This finding has been determined to be of low to moderate safety significance (White). This finding does not represent an immediate safety concern because of the corrective actions you have taken. These actions included restoring EDG 1-02 to an operable status, ensuring that all other EDGs were not in a similar degraded condition, and curtailing painting activities pending the implementation of suitable measures to prevent the recurrence of a similar condition.

You have 30 calendar days from the date of this letter to appeal the NRC's determination of significance for the identified White finding. Such appeals will be considered to have merit only if they meet the criteria given in NRC Inspection Manual Chapter 0609, Attachment 2. In accordance with the NRC Enforcement Policy, the Notice of Violation is considered an escalated enforcement action because it is associated with a White finding.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response.

In addition, we will use the NRC Action Matrix to determine the most appropriate NRC response to this issue, and we will notify you by separate correspondence of that determination.

The report also documents one NRC-identified finding of very low safety significance (Green). This finding was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it is entered into your corrective action program, the NRC is treating the finding as a noncited violation (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest this NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Comanche Peak Steam Electric Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the

NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room). To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction.

Sincerely,

/RA/

Elmo E. Collins
Regional Administrator

Dockets: 50-445
Licenses: NPF-87

Enclosures:
1. Notice of Violation
2. NRC Inspection Report 05000445/2007008
   w/Attachments

Attachment 1: Supplemental Information
Attachment 2: Special Inspection Charter
Attachment 3: Significance Determination Evaluation

cc w/enclosures:
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Dricks - VLD	WMaier - WAM	R Barnes, OE
DPowers - DAP	DPelton - DLP1	

SUNSI Review Completed: CEJ ADAMS: √ Yes ☐ No Initials: CEJ

√ Publicly Available ☐ Non-Publicly Available ☐ Sensitive √ Non-Sensitive

R:_REACTORS_CPSES\2007\CP2007-08 CHY.wpd ADAMS ML080600164

RIV:RI:DRP/E	SRI:DRP/E	SRA	C:DRP/A	SES/ACES
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E-CEJ	E-CEJ	/RA/	/RA/	/RA/
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NOTICE OF VIOLATION

Luminant Generation Company, LLC
Comanche Peak Steam Electric Station

Docket No. 50-445
License No. NPF-87
EA-08-028

During an NRC inspection completed on January 24, 2008, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

> Unit 1 Technical Specification (TS) 3.8.1, "AC Sources - Operating," requires that while the plant is in Modes 1, 2, 3, or 4, two diesel generators (DGs) capable of supplying the onsite Class 1E power distribution subsystem(s) shall be operable. For the condition of one DG being inoperable, the required action is to restore the DG to an operable status within 72 hours and within 6 days from the discovery of the failure to meet the Limiting Condition for Operation (LCO), or be in Mode 3 within 6 hours and Mode 5 within 36 hours.
>
> Contrary to the above, from November 1, 2007, through November 21, 2007, while the plant was in Mode 1, one of the two DGs capable of supplying the onsite Class 1E power distribution subsystem(s) was inoperable, and action was not taken to either restore the DG to an operable status within 72 hours or be in Mode 3 within 6 hours and Mode 5 within 36 hours. Specifically, Emergency Diesel Generator (EDG) 1-02 was made inoperable as a result of painting activities due to paint having been deposited and remaining on at least one fuel rack in a location that prevented motion required to support the operation of the EDG. This condition caused EDG 1-02 to fail to start during a surveillance test on November 21, 2007.
>
> This violation is associated with a White significance determination process finding.

Pursuant to the provisions of 10 CFR 2.201, Luminant Generation Company, LLC is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region IV, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-08-028," and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps that will be taken to avoid further violations and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated this 29th day of February 2008.

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-445
Licenses:	NPF-87
Report:	05000445/2007008
Licensee:	Luminant Generation Company, LLC
Facility:	Comanche Peak Steam Electric Station, Unit 1
Location:	FM-56, Glen Rose, Texas
Dates:	December 4, 2007, through January 24, 2008
Team Leader:	C. Young, P.E., Resident Inspector, Arkansas Nuclear One
Inspectors:	A. Sanchez, Resident Inspector, Comanche Peak Steam Electric Station D. Loveless, Senior Reactor Analyst
Branch Chief:	C. Johnson, Chief, Project Branch A Division of Reactor Projects
Approved By:	D. Chamberlain, Director Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000445/2007008; 12/04/07 - 01/24/08; Comanche Peak Steam Electric Station (CPSES), Unit 1; Special Inspection in response to the failure of the Train B Emergency Diesel Generator to start on demand on November 21, 2007.

The report covered a 6-day period (December 4-7, 2007) of onsite inspection, with inoffice review through January 24, 2008, by a special inspection team consisting of two resident inspectors and one senior reactor analyst. Two findings were identified, including one Green noncited violation, and one White violation. The significance of most findings is indicated by its color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- White. A violation of Unit 1 Technical Specification 3.8.1, "AC Sources - Operating," was identified for the licensee's failure to satisfy Limiting Condition for Operation 3.8.1 in that painting activities conducted on the Unit 1 Train B EDG 1-02 resulted in paint being deposited and left in a location that caused the EDG to become inoperable. As a result, EDG 1-02 failed to start on demand during the subsequent monthly surveillance test. Following the discovery of the condition, the required actions were satisfied; however, the time period between the occurrence of the condition and the discovery of the condition exceeded the allowed outage time. This issue was entered into the licensee's corrective action program as SMF-2007-03253.

  The finding was greater than minor because it was associated with the human performance attribute of the mitigating systems cornerstone, and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The Phase 1 Worksheets in Manual Chapter 0609, "Significance Determination Process," were used to conclude that a Phase 2 analysis was required because the performance deficiency affected the emergency power supply system that is a support system for both mitigating and containment barrier systems. Based on the results of the Phase 2 analysis, the finding was determined to have low to moderate safety significance (White). The senior reactor analyst determined that a more detailed Phase 3 analysis was needed to fully assess the safety significance. Based on the results of the Phase 3 analysis, the finding was determined to have low to moderate safety significance (White). The Phase 1, 2, and 3 Significance Determination Process analyses associated with this finding, including assumptions and limiting core damage sequences, is included as Attachment 3 to this report. The cause of this finding was determined to have a crosscutting aspect in the area of human performance associated with work practices in that the licensee failed to provide adequate supervisory and management oversight of work activities, including contractors, such that nuclear safety is supported [H.4(c)]. Specifically, the actions planned and taken to assess and control the operational impact of the painting activities on the functionality of the emergency diesel generator were not reflective of adequate supervisory and management oversight of the activities (Section 2.1).

- Green. The inspectors identified a noncited violation of Unit 1 Technical Specification 5.4.1.a, “Procedures,” for an inadequate alarm response procedure. The inspectors determined that Procedure ALM-1302A, “Diesel Generator 1-02 Panel,” Revision 5, was inadequate in that it was ambiguous and did not cause the responders to verify that the fuel racks were free as part of the response actions to investigate the cause of the unit failing to start. Consequently, the licensee failed to identify that the Unit 1 Train B Emergency Diesel Generator 1-02 fuel racks were not free to move, which led to an extended period of inoperability and a significant delay in diagnosing the cause of the emergency diesel generator failure to start. This issue was entered into the licensee’s corrective action program as SMF-2007-03426.

  The finding was determined to be more than minor because it was associated with the procedure quality attribute of the mitigating systems cornerstone, and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheet, the finding was determined to have very low safety significance (Green) because it was not a design or qualification deficiency, did not represent a loss of safety function, did not represent an actual loss of a single train for greater than its Technical Specification allowed outage time, did not represent a loss of a non-Technical Specification Train of equipment for greater than 24 hours, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event (Section 2.2).

B. Licensee-Identified Violations

None.

REPORT DETAILS

1.0 SPECIAL INSPECTION SCOPE

The NRC conducted a special inspection at Comanche Peak Steam Electric Station to better understand the circumstances surrounding the failure of the Unit 1 Train B Emergency Diesel Generator (EDG) 1-02 to start on demand during a monthly surveillance test on November 21, 2007. Following approximately 11 hours of troubleshooting, EDG 1-02 was restored to an operable status. In accordance with NRC Management Directive 8.3, it was determined that the period of inoperability of the EDG, both prior to and during the failure to start event, had sufficient risk significance to warrant a special inspection. The initial incremental conditional core damage probability associated with the assumed period of EDG inoperability was estimated to be 1.76×10^{-5}. The possibility that adverse generic implications were associated with the EDG failure mechanism was the deterministic criterion met to warrant a special inspection.

The team conducted the inspection in accordance with Inspection Procedure 93812, “Special Inspection,” and the inspection charter, which is included in this report as Attachment 2. The special inspection team reviewed procedures, corrective action documents, operator logs, and maintenance records for the EDG system. The team interviewed various licensee personnel regarding the events that led up to and response actions that followed the EDG failure, as well as design and operational characteristics of the EDG and its support systems. The team reviewed the licensee’s root cause analysis report, past failure records, extent of condition evaluation, immediate and long term corrective actions, and industry operating experience. A list of specific documents reviewed is provided in Attachment 1.

1.1 Event Summary

On November 21, 2007, at 10:20 a.m., EDG 1-02 failed to start on demand during a monthly slow start surveillance test. Prior to this, the last successful surveillance test on EDG 1-02 was on October 24, 2007. The licensee’s response to the failure to start is described in Section 1.2 below. Troubleshooting efforts were ultimately successful, and EDG 1-02 was restored to an operable status at 3:08 a.m. on November 22, 2007. The failure was determined to be the result of fuel racks being stuck in the closed positions, and not responding to a full open governor demand, thereby preventing sufficient fuel from reaching the engine. The failure mechanism is described in Section 1.4 below. The cause of the fuel rack binding was ultimately determined to be a drop of paint on a fuel rack which prevented the rack from being able to move through the fuel pump housing. The root and contributing causes of this failure are discussed on Section 1.3 below.

Prior to the failed surveillance test on November 21, 2007, painting was conducted on and around EDG 1-02 and EDG 2-02 (Unit 2 Train B EDG). The painting activities associated with EDG 1-02 began on October 15, 2007, and continued through November 8, 2007.

Included below is a timeline that includes significant elements pertaining to this event.

Date/Time	Event
October 15, 2007	Painting begins on EDG 1-02 on top of engine and around heads.
October 15, 2007 - November 1, 2007	Painting activities continue on a daily basis.
October 24, 2007	Successful monthly slow start surveillance test of EDG 1-02. No painting is done on this day.
October 29, 2007 - November 1, 2007	Painting occurs around the 6L fuel pump.
November 1, 2007	Painting in locations that could have reasonably resulted in stray paint/drops on fuel rack(s) is completed.
November 21, 2007 3:28 a.m.	EDG 1-02 declared inoperable due to bar over in preparation for monthly surveillance test.
4:09 a.m.	Bar over completed. Successful water roll via the air start system was completed. EDG 1-02 declared operable.
10:17 a.m.	EDG 1-02 declared inoperable for monthly surveillance test.
10:20 a.m.	EDG 1-02 failed to start on demand for monthly slow start surveillance test. Operations personnel believed the EDG did not roll. Troubleshooting commences.
4:49 p.m.	Slow start attempt of EDG 1-02 resulted in EDG rolling up to 90-100 rpm and failing to start. Troubleshooting continues.
6:02 p.m.	Fast start attempt of EDG 1-02 resulted in a failure to start. Fuel racks were observed not to move in response to a governor demand.
7:39 p.m.	Fuel racks were manually stroked. Rack 6L was found to be stuck. Rack 2L moved approximately half of its travel range, then became bound. Both racks were freed and stroked until normal free range of motion was restored.
9:25 p.m.	Walkdown inspections revealed residual paint on 6L, 4L, and 4R fuel racks. Residue of paint on 6L was wiped away.
9:32 p.m.	Successful start and run of EDG 1-02.
November 22, 2007 3:08 a.m.	EDG 1-02 was declared operable.

1.2 Licensee Response to the Failure of the EDG to Start

The inspectors evaluated the licensee's implementation of procedures (abnormal, alarm, troubleshooting, and normal operations) and Technical Specifications, reviewed plant management's control and decision making actions, and reviewed the troubleshooting and investigating activities that occurred following the Unit 1 Train B EDG failure to start during the monthly surveillance test on November 21, 2007. The inspectors reviewed corrective action documents, procedures, Technical Specifications, and operations logs. The team performed system walkdowns and interviewed engineering, maintenance, and operations personnel.

The inspectors determined that, in general, the licensee responded to the event properly and in accordance with plant procedures. Nuclear equipment operators (NEO) quickly identified that the EDG 1-02 failed to start and immediately responded to the local EDG alarm panel. The operations field support supervisor performed an inspection to look for any obvious problems that could have caused the EDG to fail. NEOs noted that it did not sound like a normal start, and assumed that a possible issue associated with the starting air system had something to do with the failure to start. The licensee had already declared the EDG inoperable prior to the attempted start in conjunction with the surveillance test.

In response to the Unit Failure To Start alarm on the local EDG alarm panel, NEOs performed the steps of the local alarm panel procedure, Alarm Procedure Manual ALM-1302A, "Diesel Generator 1-02 Panel," Revision 5, which instructed the operations personnel to investigate the cause of the failure. This included checking for proper operation and issues associated with the fuel racks, day tank, and the starting air system. One of the applicable steps was to "check fuel racks free." This was accomplished in accordance with the expectations of senior operations personnel by visually verifying that there were no apparent conditions that would obstruct the motion of the fuel racks. No abnormalities were identified at this time.

The operations staff reviewed drawings and diagrams, interviewed the NEOs, and consulted with meter and relay representatives, system engineering department personnel, and the mechanical services department to develop a troubleshooting plan. Due in large part to the testimony of the NEOs that the EDG did not even roll in response to the start attempt, the troubleshooting plan focused on the starting air system as the suspected cause of the failed start. The plan called for meter and relay personnel to monitor various solenoids and relays during a subsequent slow start attempt of the EDG. This attempt resulted in the EDG rolling up to 90-100 rpm, and again failing to start. Indications now suggested that a fuel-related problem must exist, and focus was shifted accordingly. A third attempt was performed with the EDG in a fast start configuration. Again, the EDG failed to start. Observers noted that the fuel racks did not move from their closed positions in response to the mechanical governor's attempt to drive the fuel racks to the full open position. The licensee then attempted to exercise the fuel racks and metering rods individually and discovered that two metering rods (2L and 6L) were partially and fully bound, respectively. Licensee personnel physically exercised the metering rods until they were free to move, and removed evidence of paint that was found to be on the 6L metering rod by the fuel pump housing interface. The licensee then performed a fourth attempt to start EDG 1-02, which was successful. The EDG was fully loaded, and operations personnel completed the surveillance testing. The EDG 1-02 was subsequently declared operable on the morning of November 22, 2007 at 3:08 a.m.

The inspectors determined that the initial troubleshooting plan was too narrowly focused on finding an EDG starting air problem (despite a successful water roll via the air start system that occurred earlier that morning), as opposed to pursuing all likely causes of a failed start. If the focus of the response were broader, it is likely that the stuck metering rod would have been discovered earlier, and the duration of EDG inoperability following the failed start would have been reduced.

Subsequently during the troubleshooting efforts, the joint engineering team developed a confirm and refute matrix to process the results from troubleshooting. Possible causes that were analyzed over the course of troubleshooting included:

- Starting air receiver discharge valves mispositioned
- Manual stop button mispositioned
- Tachometers operational
- Malfunctioning of air start solenoid valves
- Mechanical governor bound
- Fuel supply to the engine
- Main control board handswitch
- Electronic governor not operating
- Fuel racks not functioning*

*Determined to be the cause of the failure

As described in Section 1.3 below, the Unit 2 Train B EDG was also in the process of being painted. Once the cause of EDG 1-02 inoperability was determined to be stuck metering fuel rods, the operations staff inspected the Unit 2 Train B EDG and determined that the same issue did not exist. Operations also inspected the Units 1 and 2 Train A EDGs and determined that the stuck metering rods issue did not exist. The Unit 1 Train B EDG was the only EDG affected.

1.3 Root Cause and Corrective Action Assessment

.1 Root Cause Analysis

The inspectors reviewed and assessed the licensee’s root cause analysis for technique, accuracy, thoroughness, and corrective actions proposed and taken. The inspectors reviewed the scope and processes used by licensee personnel to identify the root cause for the failure of the Unit 1 Train B EDG to start during a monthly surveillance test. The inspectors compared information gained through inspection to the event information and assumptions made in the root cause reports. The inspectors interviewed licensee personnel, reviewed logs, reviewed personal statements, and observed root cause team meetings. The inspectors evaluated the licensee’s extent of condition review and common cause evaluation.

The licensee captured the EDG 1-02 failure to start problem in the corrective action program as SMF-2007-03253, and performed a root cause analysis in response to determine the cause of the failure. Evaluation techniques utilized by the licensee included an Events and Causal Factors Chart and a Barrier Analysis. The result of these efforts identified the most probable root cause of the failure to be a drop of paint that was deposited and adhered to the 6L fuel rack in a location that prevented the rack (along with all other fuel racks) from moving in the open direction in response to the governor demand associated with an EDG start signal. This failure mechanism is further discussed in Section 1.4 below. Although there was no documented evidence of the actual paint drop, there was paint residue observed which remained in the subject location following the manual manipulation and freeing of the stuck fuel rack during troubleshooting. This residue was wiped off upon discovery.

Additionally, the following four contributing causes to the failure were identified in the final root cause analysis:

- Work practices of painters and other groups who performed daily inspections failed to identify paint spatter and drops that should have been cleaned off sensitive engine components.

- The tools and techniques used by painters were not completely effective in preventing paint spatter and drips.

- *Because the directions in alarm response procedure ALM-1302A were not specific, the time period following the failure until the discovery of the cause of the problem was extended.

- The fuel control shaft break away force may have increased over time due to wear and aging effects. This may have added to the force required to overcome the adhesion of the paint drop.

*This issue was also identified early in the inspection process by the inspectors and is further discussed in Section 2.2 below.

The root cause team assessed that the engineering confirm/refute evaluation performed during troubleshooting, along with the subsequent investigative actions outlined below, were effective in considering and ruling out all other potential causes of the failure:

- Electrical and control circuitry problems were investigated and ruled out. Due to the initial reports that the field operator did not believe that the EDG even rolled over, the root cause team investigated other possibilities that could have caused the EDG not to have rolled, and still brought in the alarms that were received. One viable possibility considered was a possible fault associated with the EDG Start/Stop hand switch in the control room. The hand switch in question was a piece of original equipment. One of the corrective actions was to replace the hand switch when the 6L fuel pump and metering rod was replaced after the event. The switch was bench tested, disassembled, and inspected, and it was determined that the switch not only functioned properly without signs of degradation, but it would not be physically possible to have the switch manipulated to send a stop signal to the diesel while an operator takes the switch to the start position. The inspectors performed a visual inspection of the switch internals and reviewed the testing methods and results. The inspectors concluded that the EDG start/stop control switch would not have caused the EDG failure to start on November 21, 2007.

- The starting air system was examined and proven to be functional. The inspectors confirmed this by performing system walkdowns. A water roll check was performed satisfactorily.

- The fuel day tank was inspected to ensure proper alignment and fuel quality.

- Inspections of the joints that connect the fuel pump control shaft levers to the fuel racks were performed, and determined that none were exhibiting mechanical binding. The inspectors confirmed this by performing a system walkdown.

- The 6L fuel pump was replaced and sent to the vendor for testing, disassembly, and inspection. No abnormalities were identified, and internal binding of the pump was determined not to be a cause of the event.

- The capability of single paint drop to counter the force applied and prevent the motion of the fuel control shafts was assessed. A spare fuel pump was subjected to a series of field tests to determine the force required to overcome the adhesion of a drop of paint in the location that had been identified. The results were consistent with the hypothesis that the force applied from the mechanical governor could have been overcome by the presence of the paint drop becoming wedged in the minimal clearance between the fuel rack and the pump housing. Another pull test was done to confirm that a fuel rack exposed to various combinations of dirt and grit would not require appreciably more pull tension to operate.

Aspects of organizational and programmatic effectiveness were also evaluated by the root cause team, and confirmed by the inspectors. These included inadequate supervisory and management involvement with the painting activities, work practices employed during the job, and the less than comprehensive development of the procedures and work packages associated with the activity.

The extent of the condition that was determined to be the cause of the EDG 1-02 failure was assessed by the root cause team. All other EDGs were thoroughly inspected to verify that the same condition did not exist, particularly with the Unit 2 Train B EDG 2-02, which had been similarly painted in September and October. All other EDGs were verified to be free of the subject degraded condition. Emergency Diesel Generator 2-02 successfully passed its monthly surveillance test on November 28, 2007. The inspectors reviewed the licensee's actions and concluded that the licensee's extent of condition evaluation was adequate.

The inspectors concluded, following interviews as well as a review of personal statements made by the maintenance personnel, that the work practices of painters and other work groups who performed daily paint clean-up inspections to identify paint spatter and drops that needed to be cleaned off of sensitive engine components was a valid contributor to the event. The inspectors also determined that neither documentation nor feedback from the inspections to the painters or operations management regarding the results of those inspections was performed. The communication of those results, to the right individuals, could have identified the need to reinforce expectations, alter paint methods or barriers, or institute a stand down that may have led to the prevention of the event. At a minimum, communication between organizations (maintenance, inspection, operations, and management) was not as strong as it could have been for this work on highly risk significant, safety-related equipment.

Along with the discussion above, the inspections that were performed as part of the postpainting activities were agreed upon between operations and maintenance. Neither the inspections nor any other applicable postmaintenance testing was specified by the work order for performing the painting activities. Also, there was no discussion concerning foreign materials control exclusion (FME) controls. FME has been a significant issue with the licensee in the recent past, but no mention of this sensitivity was made. The inspections that were performed were not documented anywhere as having been done nor were any of the findings stemming from the inspections.

The inspectors found that the licensee assembled an effective root cause team. The root cause team investigated every lead that was available to determine exactly why the Unit 1 Train B EDG failed to start on November 21, 2007. The inspectors determined that the scope, methods, and rigor associated with the root cause analysis were appropriate and consistent with the safety significance of the problem, and that the evaluation was successful in determining and addressing the most probable root and contributing causes of this issue.

.2 Corrective Action Assessment

The inspectors evaluated the scope, adequacy, and timeliness of the licensee’s corrective measures that were both planned and implemented in response to the cause of the EDG 1-02 failure. The inspectors concluded that the actions planned and taken by the licensee were appropriate to address the degraded condition, to result in the prevention of a future similar failure, and were consistent with the safety significance of the event. Corrective actions to be taken prior to resuming painting activities include:

- Revise Procedure MSM-G0-0220 used for painting to require a shiftly manipulation of the fuel racks in addition to a visual inspection of components to be free of paint spatter/drops

- Verify the information contained in the painting pre-job briefing book to ensure it contains all sensitive areas on the EDG that should not be painted

- Revise Procedure MSM-G0-0220 to include pictures and other information contained in the painters’ prejob briefing book used during EDG painting

- Revise Procedure MSM-G0-0220 to provide for “as you go” inspections and cleaning when painting is done around sensitive components

- Include this event in prejob briefings for future activities to heighten sensitivity to the potential effects of paint spatter/drops in areas that can bind mechanical components or block air pathways

- Improve tools and techniques used by painters to minimize drops and spatter. Also research available FME barriers that could be used to shield sensitive areas

Additional planned corrective actions include:

- Develop a preventive maintenance activity to perform a fuel control shaft break away force test to monitor for potential degradation in the shaft linkage or bearings

- Revise alarm response Procedure ALM-1302A to remove ambiguity regarding checking components for freedom of movement by providing specific instruction to include a manual manipulation of the components

1.4 Scope of the Failure Mechanism

The inspectors, through inspection and investigation, interviews of system engineers, reviews of EDG design documentation, and assessment of the licensee's root cause analysis, developed a scope of the mechanism that was determined to be the root cause of the EDG 1-02 failure. The fuel pump control racks (fuel metering rods) were prevented from moving from their normal standby (closed) positions in response to a governor demand by the presence of a drop of paint that had adhered to the fuel rack in a location where the rack enters the housing of the fuel pump (with very minimal clearance) when moving in the open direction. Since all fuel racks are mechanically linked by the common fuel control shafts and cross shaft linkages, the motion of the entire system in the open direction (back to the extensible link from the mechanical governor) was inhibited by one fuel rack that was stuck in the standby (closed) position. A torsion spring on the control shaft associated with each fuel pump control shaft lever functions to allow continued motion of the system in the closed direction if one or more individual fuel racks become bound. However, the feature does not provide this function for system motion in the open direction, as in the response to an EDG start signal.

1.5 Event Precursors

The root cause of the EDG failure to start was determined to be paint that was inadvertently dropped onto a fuel pump metering rod. The inspectors reviewed corrective action documents and interviewed system engineers in order to identify any previous related issues that may have been precursors to the Unit 1 Train B EDG failure to start. The inspectors reviewed all available documented issues dating back to 1999 that fell into each of the following two categories: (1) Previous similar or related EDG failures, and (2) Previous issues involving equipment failures related to painting. The inspectors determined that there had been no previous EDG or painting related issues that may have been precursors to this event.

1.6 EDG Maintenance and Testing

The inspectors reviewed the licensee's EDG Maintenance and testing programs. The inspectors reviewed maintenance and testing records as well as the licensee's plans and schedules related to preventive maintenance and testing of the EDGs. The inspectors also interviewed several system engineers to gain an understanding of the licensee's approaches and programs involving EDG maintenance and testing. The inspectors determined that the licensee's EDG routine maintenance and testing programs are adequate and that the licensee is following the program provisions. However, the inspectors determined that these maintenance and testing practices for painting activities were not adequate as discussed in Section 2.0.

1.7 Industry Operating Experience (OE)

The inspectors reviewed the industry operating experience (OE) the licensee gained through their normal review, as well as that which was referenced in the licensee's root cause evaluation. The inspectors conducted interviews of licensee personnel, reviews of pertinent OE materials discovered independently as well as with the assistance of the NRC's Operating Experience Section, and an evaluation of actions taken by the licensee in response to relevant OE. The specific documents reviewed during this review is listed in Attachment 1 of this report.

The inspectors determined that the licensee had appropriately reviewed and incorporated OE associated with the circumstances of the EDG failure, and that a failure to incorporate applicable OE into station practices was not a contributing cause to the EDG failure. The inspectors reviewed several items of OE, inspection reports, and licensee event reports (LERs). The inspectors reviewed the licensee's responses to the applicable cases. The licensee did have all of the OE in their OE review system, with the exception of LERs. The licensee reviews industry OE that comes from INPO and not specifically the LER database. It appeared that the licensee had accounted for all available OE at the time that could have reasonably been obtained and reviewed.

All of the OE pertaining to notification events of inoperable diesels due to painting described gross painting errors that resulted in inoperable diesel generators (e.g., inappropriate/movable components being painted). The licensee did take those events into consideration when developing the work plan for painting of the EDGs in the associated rooms. The licensee held meetings well in advance of the scheduled painting window, ensured that operations and maintenance personnel were communicating, and developed a painter's handbook that presented precautions as well as clear photographs of the areas and components not to paint. The preparation was adequate for the knowledge that the plant had on site at the time. The sensitivity that one paint drop in a specific, unintended location could render the EDG inoperable was not considered by the licensee in their preparation and conduct of the EDG painting activities, but this was not a subject of previous OE.

One item that was not specifically incorporated into the procedures for painting the EDG was a specific postmaintenance test to be performed to prove operability. The licensee's procedure described and recommended any of several postmaintenance options, including visual inspections and equipment functionality tests. This procedure and its weaknesses were discussed as part of the root cause evaluation in Section 1.3.

The licensee sent two of its employees (a system engineer and a painting supervisor) on a benchmarking trip prior to cleaning up, painting, and relamping the EDG Rooms. The licensee employees were aware of the potential to make the EDG inoperable by painting activities, but did not get enough information to be as sensitive as necessary for their painting activities. After the failed EDG start, the licensee called the plants visited during the benchmarking trip to ask more questions, and then discovered that one plant had knowledge that very little paint or other foreign materials on the metering rods could render the EDG inoperable. The licensee could have possibly obtained this information if their staff were to have asked more probing questions, given the work that was planned at the site. The inspectors concluded that the licensee was not fully effective in addressing operating experience associated with painting impacts on emergency diesel generator operability.

1.8 Potential Generic Issues

The inspection team evaluated the circumstances surrounding the event and assessed the root cause of the Unit 1Train B EDG failure to start. The team interviewed numerous licensee personnel and reviewed industry operating experience as well as NRC generic communications with the goal of identifying any potential generic issues that should be addressed as a result of the event.

The inspection team concluded that, while painting activities occur at all plants, there are no specific generic concerns associated with this instance of procedural compliance. The licensee has also issued an action in the corrective action program to issue an OE report to INPO for future reference.

2.0 SPECIAL INSPECTION FINDINGS

2.1 Painting Activities Result in Inoperability of EDG

Introduction: A White self-revealing violation of Unit 1 Technical Specification (TS) 3.8.1, “AC Sources - Operating,” was identified for the licensee’s failure to satisfy TS LCO 3.8.1 in that painting activities conducted on the Unit 1 Train B EDG 1-02 resulted in paint being deposited and left in a location that caused the EDG to become inoperable. As a result, EDG 1-02 failed to start on demand during the subsequent monthly surveillance test. Following the discovery of the condition, the TS required actions were satisfied; however, the time period between the occurrence of the condition and the discovery of the condition exceeded the TS allowed outage time.

Description: On October 15, 2007, the licensee commenced painting activities that occurred on and around EDG 1-02. A successful monthly slow start surveillance test was performed on October 24, 2007. Painting activities continued through November 1, 2007. The inspectors reviewed Work Order (WO) 4-07-175968-00, which implemented the painting activities on and around EDG 1-02 and specified that painting was to be performed per the requirements of Procedure MSM-G0-0220, “General Plant Painting,” Revision 2. The inspectors noted that the WO did not contain requirements for postmaintenance testing of the EDG, and that Procedure MSM-G0-0220, “General Plant Painting,” Revision 2, contained the following steps:

> NOTE: System engineer, operations, maintenance services or other departments may provide useful guidance in determining appropriate protection of equipment and post-painting functional testing.
>
> **5.1.1.2** Painting conducted on equipment should be done in such a manner as to ensure paint does not bind components required to move. Prejob briefings, visual verification of postpainting operation, equipment functional testing or other similar activities are recommended practices that should be employed when painting equipment.

Through interviews, the inspectors determined that representatives from the maintenance services, system engineering, maintenance, and operations departments discussed plans for verifying at the end of each day that the EDG remained operable. The above requirement and guidance of the general plant painting procedure was not referenced in this discussion. It was decided that a senior operations department personnel would perform a visual inspection at the end of each day to verify that painting had not been done so as to affect the operability of the EDG. This plan was understood and executed, but was not documented, nor were any inspection results documented. Prejob briefs and postpainting inspections were focused on avoiding the painting of components that were not supposed to be painted and were appropriate and effective in that regard. However, appropriate sensitivity to the potential functional impact of stray drop(s) of paint in sensitive location(s) was not emphasized.

On November 21, 2007, EDG 1-02 failed to start on demand during its next monthly surveillance test. Following approximately 11 hours of troubleshooting, EDG 1-02 was successfully started. This issue was entered into the licensee’s corrective action program as SMF-2007-003253-00. The licensee performed a root cause analysis to determine the cause of the failure. The most likely cause of the failure was determined to be a paint drop that had been deposited on the 6L fuel rack that caused the rack to become stuck. This prevented motion of all 16 fuel racks, thereby preventing the EDG from receiving sufficient fuel to run. Corrective actions planned and taken by the licensee are discussed in Section 1.3 of this enclosure.

<u>Analysis</u>: The performance deficiency associated with this finding involved the licensee’s failure to ensure that the assumed operability of safety-related equipment was not affected by the performance of scheduled maintenance activities. Specifically, painting was conducted on and around EDG 1-02 in such a manner that paint was deposited and remained in a location that caused the EDG to become inoperable and fail to start on demand during a subsequent surveillance test. Postpainting verification of equipment functionality was inadequate. Consequently, the requirements of TS LCO 3.8.1.b and the associated required TS Actions B.4 and G.1 and 2 were not met. The finding was greater than minor because it was associated with the human performance attribute of the mitigating systems cornerstone, and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The Phase 1 Worksheets in Manual Chapter 0609, “Significance Determination Process,” were used to conclude that a

Phase 2 analysis was required because the performance deficiency affected the emergency power supply system that is a support system for both mitigating and containment barrier systems. Based on the results of the Phase 2 analysis, the finding was determined to have low to moderate safety significance (White). The senior reactor analyst determined that a more detailed Phase 3 analysis was needed to fully assess the safety significance. Based on the results of the Phase 3 analysis, the finding was determined to have low to moderate safety significance (White). The Phase 1, 2, and 3 significance determination process analyses associated with this finding, including assumptions and limiting core damage sequences, is included as Attachment 3 to this report. The cause of this finding was determined to have a crosscutting aspect in the area of human performance associated with work practices in that the licensee failed to provide adequate supervisory and management oversight of work activities, including contractors, such that nuclear safety is supported [H.4(c)]. Specifically, the actions planned and taken to assess and control the operational impact of the painting activities on the functionality of the EDG were not reflective of adequate supervisory and management oversight of the activities.

Enforcement: Unit 1 Technical Specification (TS) 3.8.1, "AC Sources - Operating," requires that while the plant is in Modes 1, 2, 3, or 4, two diesel generators (DGs) capable of supplying the onsite Class 1E power distribution subsystem(s) shall be operable. For the condition of one DG being inoperable, the required action is to restore the DG to an operable status within 72 hours and within 6 days from the discovery of the failure to meet the Limiting Condition for Operation (LCO), or be in Mode 3 within 6 hours and Mode 5 within 36 hours. Contrary to the above, from November 1, 2007, through November 21, 2007, while the plant was in Mode 1, one of the two DGs capable of supplying the onsite Class 1E power distribution subsystem(s) was inoperable, and action was not taken to either restore the DG to an operable status within 72 hours or be in Mode 3 within 6 hours and Mode 5 within 36 hours. Specifically, Emergency Diesel Generator (EDG) 1-02 was made inoperable as a result of painting activities due to paint having been deposited and remaining on at least one fuel rack in a location that prevented motion required to support the operation of the EDG. This condition caused EDG 1-02 to fail to start during a surveillance test on November 21, 2007. Following the discovery of the condition on November 21, 2007, the licensee satisfied the TS required actions by restoring the EDG to an operable status on November 22, 2007. This violation is the subject of the enclosed Notice of Violation: VIO 05000445/2007008-01, "Painting Activities Result in Inoperability of Emergency Diesel Generator."

2.2 Inadequate Alarm Response Procedure for EDG Failure to Start

Introduction: The inspectors identified a Green noncited violation of Unit 1 Technical Specification 5.4.1.a, "Procedures," for an inadequate alarm response procedure. The inspectors determined that Procedure ALM-1302A, "Diesel Generator 1-02 Panel," Revision 5, was inadequate in that it was ambiguous and did not cause the responders to verify that the fuel racks were free as part of the response actions to investigate the cause of the unit failing to start. Consequently, the licensee failed to identify that the Unit 1 Train B EDG 1-02 fuel racks were not free to move, which led to an extended period of inoperability and a significant delay in diagnosing the cause of the EDG failure to start.

Description: On November 21, 2007, at 10:20 a.m., EDG 1-02 failed to start during a slow start monthly surveillance test. Field operators responded to the EDG local alarm panel. Operators referenced the alarm response Procedure ALM-1302A, "Diesel Generator 1-02 Panel," Revision 5, and reviewed the section for Alarm Window 6.6 "Unit Failure To Start." A limited number of system malfunctions that could have caused the failure to start were indicated. These included fuel rack or fuel oil day tank issues, improper starting air alignment, failed timing chain, and a Governor malfunction.

Operators implemented the "Operator Actions" section of the procedure, which included actions to determine the cause of the unit failing to start. The first action indicated was to "Check fuel racks free and in max fuel position." The field support supervisor (senior reactor operator) believed that the appropriate action was to perform a visual inspection of the fuel racks. The fuel racks were not in the "max fuel" position. The inspectors later determined that, following the majority of postulated failed start scenarios, the fuel racks would not be expected to remain in the "max fuel" position, even if they had initially moved. In accordance with the operators' training, the expectation for performing this step was to visually inspect the racks. However, the inspectors determined that without observing them being in a position other than their normal standby (closed) position, this visual check would not be sufficient to meet the intent of the procedure step (i.e., to ensure that the racks were not stuck in the "no fuel" position, which was a probable failure cause that was indicated earlier in the procedure). The operator completed this procedure step, as well as subsequent steps for starting air alignment, EDG day tank alignment, and fuel quality with no abnormalities identified. Field operator actions were completed at 11:05 a.m.

The licensee developed a troubleshooting plan and attempted two more starts of the EDG (both unsuccessful) before determining that the fuel racks and metering rods were not responding to the Governor demand to open. At 7:39 p.m. the licensee exercised the fuel racks and discovered that two of the metering rods were stuck, with one fully stuck in the closed position and one which became partially stuck following some motion in the open direction. Operations and maintenance performed followup inspections and successfully started the EDG at 9:32 p.m. The diesel was declared operable following the surveillance run and post run inspections on November 22, 2007 at 3:08 a.m.

The inspectors concluded that the field operators performed the actions of the alarm response Procedure ALM-1302A, in accordance with station procedures and training, and operations management's expectations. The inspectors further concluded that the inadequacy of the alarm response procedure to give clear instruction and guidance to ensure that the EDG fuel racks were verified to be free and not binding resulted in missing an opportunity to identify the cause of the EDG failure to start in a timely manner. This missed diagnosis not only led to a narrowly focused troubleshooting effort by the licensee, but also allowed the EDG to remain unnecessarily inoperable for approximately an additional 8.5 hours.

Analysis: The performance deficiency associated with this finding involved the licensee's failure to adequately establish clear procedure guidelines to implement alarm response Procedure ALM-1302A. This resulted in the licensee's failure to identify the binding of the Unit 1 Train B EDG fuel racks and metering rods in a timely manner following a failure to start. The finding was determined to be more than minor because it was associated with the procedure quality attribute of the mitigating systems cornerstone, and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheet, the finding was determined to have very low safety significance (Green) because it was not a design or qualification deficiency, did not represent a loss of safety function, did not represent an actual loss of a single train for greater than its Technical Specification allowed outage time, did not represent a loss of a non-Technical Specification train of equipment for greater than 24 hours, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event.

Enforcement: Unit 1 Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the procedures listed in Regulatory Guide 1.33, “Quality Assurance Program Requirements,” Revision 2, Appendix A, Section 5, for Abnormal, Off-Normal, or Alarm Conditions. Contrary to the above, on November 21, 2007, the licensee failed to adequately establish, implement, and maintain a procedure for an alarm condition. Specifically, alarm response Procedure ALM-1302A, “Diesel Generator 1-02 Panel,” Revision 5, was not adequately established and maintained, which resulted in the licensee’s failure to recognize that the EDG 1-02 fuel racks and metering rods were bound and caused the failure of the EDG to start on November 21, 2007. Consequently, the EDG remained inoperable for approximately 8.5 hours longer than necessary. Because the finding was determined to be of very low safety significance and has been entered in the licensee’s correction action program as SMF-2007-003426, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000445/2007008-02, “Inadequate Alarm Response Procedure for EDG Failure to Start.”

4OA6 Meetings, Including Exit

On December 7, 2007, and January 10, 2008, the results of this inspection were presented to Mr. R. Flores, Site Vice President, and Mr. T. Hope, Regulatory Performance Manager, respectively, and other licensee personnel who acknowledged the findings. Additionally on January 24, 2008, the final results of this inspection were presented to Mr. F. Madden, Director, Regulatory Affairs, and other members of the licensee staff who acknowledged the findings. On February 25, 2008, an additional exit meeting was conducted with Mr. T. Hope and other licensee personnel who acknowledged the findings. The inspectors confirmed that no proprietary material was retained during the inspection.

ATTACHMENT 1: Supplemental Information
ATTACHMENT 2: Special Inspection Charter
ATTACHMENT 3: Significance Determination Evaluation

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Bain, System Engineer
J. Bales, Maintenance Services
T. Bennette, Operations
M. Blevins, Senior Vice President and Chief Nuclear Officer
H. Davenport, System Engineer
D. Davis, Performance Improvement Director
R. Flores, Site Vice President
D. Goodwin, Manager, Shift Operations
T. Hope, Manager, Regulatory Performance
M. Kanavos, Plant Manager
D. Kross, Director, Operations
S. Lakdawala, Corrective Action Program Manager
F. Madden, Director, Regulatory Affairs
D. McGaughey, Manager, Shift Operations
G. Merka, Regulatory Affairs
J. Meyer, Technical Support Manager
W. Morrison, Maintenance Smart Team Manager
J. O'Quinn, Maintenance
W. Reppa, System Engineering Manager
D. Scott, Root Cause Analyst
S. Smith, Director, System Engineering
R. Sorrell, System Engineer
T. Terryah, System Engineering Manager
T. Tigner, Programs Supervisor
B. Wagner, PROMPT Team
W. Williams, Maintenance Services
M. Wisdom, System Engineering

NRC

D. Allen, Senior Resident Inspector

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000445/2007008-01	VIO	Painting Activities Result in Inoperability of Emergency Diesel Generator (Section 2.1)

Opened and Closed

05000445/2007008-02	NCV	Inadequate Alarm Response Procedure for EDG Failure to Start (Section 2.2)

Closed

None

Discussed

None

LIST OF DOCUMENTS REVIEWED

Procedures

NUMBER	TITLE	REVISION
ALM-1302A	Diesel Generator 1-02 Panel	5
MSM-G0-0002	General Plant Painting	2
MSM-P0-3374	Emergency Diesel Generator Monthly Run Related Inspections	3
OPT-215-1	Offsite Transmission Network Operability Data Sheet	14
OWI-104-28	Plant Equipment Operator Diesel Generator 1-02 Operating Log	13
OWI-104-26	Control Room Diesel Generator 1-02 Operating Log	11
MSM-G0-0216	Protective Coatings	23
MSM-G0-0217	Maintenance Protective Coatings-Concrete	0
MSM-G0-0218	Maintenance Protective Coatings-Steel	0
CMP-CV-1009	Application of Protective Coatings to Carbon Steel Surfaces in the Containment and Radiation Areas Outside of Containment	0
ODA-102	Conduct of Operations	24
ODA-401	Control of Annunciators, Instruments, and Protective Relays	9
ODA-407	Guidelines on Use of Procedures	12

OPT-214A	Emergency Diesel Operability Test	19
SOP-609	Diesel Generator System	17
STA-426	Industry Operating Experience Program	1
STA-692	Protective Coatings Program	0
TSP-503	Emergency Diesel Generator Reliability Program	3

Smart Forms

SMF-2007-03253	SMF-2007-03426	SMF-2007-03302
SMF-2007-02319		

WOs

4-07-176522	4-07-175968	4-07-176545
4-07-176543	4-07-176544	4-95-091357-00
5-05-501230-AA	4-07-176582	4-94-078722-00
5-07-502391-AK	4-07-175492	

Miscellaneous Information

Evaluation EVAL-2007-003253-02-00, "Root Cause Analysis"

"Post-Work Test Guide," Revision 12

LER 07-004-00, "Emergency Diesel Generator Failed Surveillance Test Due to Paint on Fuel Injector Control Linkage"

TUElectric Office Memorandum, CPSES-9125952, October 10, 1991

TUElectric Office Memorandum, CPSES-9108929, April 3, 1991

TUElectric Office Mamorandum, CPSES-91000861, January 11, 1991

Technical Evaluation TE# SE-90-1814

Cooper-Enterprise Clearinghouse R4/RV4 Preventative maintenance Program (PMP) for Nuclear Standby Applications, Revision 0

Operations Guideline 3, Attachment 4, "Operations Department Alarm Response Expectations," August 2006

CPNPP Operations Logs, November 21-22, 2007

Amercoat 220, Waterborne Acrylic Topcoat Product Datasheet, circa 1999

Information Notices

IN 93-76, “Inadequate Control of Paint and Cleaners for Safety-Related Equipment”
IN 91-46, “Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems”

NRC Inspection Documents

Inspection Procedure 93812, “Special Inspection,” 7/18/2007

“Special Inspection Charter to Evaluate the Comanche Peak Steam Electric Station Diesel Generator Failure to Start Event,” November 30, 2007

NRC Inspection Reports

ML073060511 (RBS)
ML072040388 (DC Cook IR 05000316/2007004)

LIST OF ACRONYMS

ADAMS	agency document and management system
CFR	*Code of Federal Regulations*
CPSES	Comanche Peak Steam Electric Station
EDG	emergency diesel generator
FME	foreign material exclusion
INPO	Institute of Nuclear Power Operations
LER	licensee event report
NRC	Nuclear Regulatory Commission
OE	operating experience
PARS	publicly available records system
NEO	nuclear equipment operator
SDP	significance determination process
SMF	smart form
WO	work order

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

November 30, 2007

MEMORANDUM TO: Cale Young, Resident Inspector, ANO
Alfred Sanchez, Resident Inspector, CPSES

FROM: Arthur T. Howell III, Director, Division of Reactor Projects AVegel for/RA/

SUBJECT: SPECIAL INSPECTION CHARTER TO EVALUATE THE COMANCHE PEAK STEAM ELECTRIC STATION DIESEL GENERATOR FAILURE TO START EVENT

A Special Inspection Team is being chartered in response to the Comanche Peak Steam Electric Station emergency diesel generator (EDG) failure to start event on November 21, 2007. You are hereby designated as the Special Inspection Team members. Mr. Cale Young, Resident Inspector, ANO, is designated as the team leader. The assigned SRA to support the team is David Loveless.

A. Basis

On November 21, 2007, Comanche Peak Unit 1 diesel generator, DG-102, failed to start during the monthly surveillance test. After several failed attempts to start the diesel, licensee engineers developed a trouble shooting plan to determine the cause of the diesel failing to start. During the trouble shooting efforts, licensee personnel identified that two fuel rack linkage/metering rods (L2 and L6) on DG-102 appeared to be binding. Additional inspections indicated that there were very small signs of paint on the metering rods for the L2 and L6 fuel pumps, but not enough to prevent movement. Painting activities in all EDG rooms were suspended until further measures were taken to prevent reoccurrence of this issue. During the trouble shooting activities, each individual fuel pump was manually operated by maintenance personnel and all but two moved freely. Maintenance personnel were able to manually move, and subsequently free, the L2 and L6 metering rods. Operations personnel then performed the surveillance test satisfactorily. Maintenance personnel verified that the metering rods on the remaining EDGs had free movement of all fuel rack linkage/metering rods.

During further investigation into when painting had occurred inside the EDG room, it was discovered that the painters continued to paint in the diesel room after the last successful surveillance test. This brings into question whether DG-102 would have been able to perform its intended function if called upon from October 24 to November 21, 2007.

This Special Inspection Team is chartered to review the circumstances related to the failure of DG-102 to start, and to assess the effectiveness of the licensee's actions for resolving these problems.

B. Scope

The team is expected to address the following:

1. Develop a chronology (time-line) that includes significant event elements.

2. Evaluate the licensee's response to the failure of the EDG to start. Ensure that plant personnel responded in accordance with plant procedures and Technical Specifications.

3. Assess the licensee's root cause determination for the EDG failure, the extent of condition review, the common cause evaluation and corrective measures. Evaluate whether the timeliness of the corrective measures are consistent with the safety significance of the problem.

4. Develop a complete scope of the failure mechanism identified by the licensee's root cause determination.

5. Identify previous EDG issues that may have been precursors to the November 1, 2007, event. Evaluate the licensee's corrective measures and extent of condition reviews for those problems.

6. Evaluate the licensee's EDG maintenance and testing programs. Verify that the programs are adequate and that the licensee is following the program provisions.

7. Evaluate pertinent industry operating experience that represents potential precursors to the November 21, 2007, event, including the effectiveness of licensee actions taken in response to the operating experience.

8. Determine if there are any potential generic issues related to the EDG failure at Comanche Peak Unit 1. Promptly communicate any potential generic issues to Region IV management.

9. Collect data as necessary to support a risk analysis. Work closely with the Senior Reactor Analyst during this inspection.

C. Guidance

Inspection Procedure 93812, “Special Inspection,” provides additional guidance to be used by the Special Inspection Team. Your duties will be as described in Inspection Procedure 93812. The inspection should emphasize fact-finding in its review of the circumstances surrounding the event. It is not the responsibility of the team to examine the regulatory process. Safety concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

The Team will report to the site, conduct an entrance, and begin inspection no later than December 4, 2007. While on site, you will provide daily status briefings to Region IV management, who will coordinate with the Office of Nuclear Reactor Regulation, to ensure that all other parties are kept informed. If information is discovered that shows a

more significant risk was associated with this issue, immediately contact Region IV management for discussion of appropriate actions. A report documenting the results of the inspection should be issued within 30 days of the completion of the inspection.

This Charter may be modified should the team develop significant new information that warrants review. Should you have any questions concerning this Charter, contact me at (817) 860-8148.

ATTACHMENT 3
SIGNIFICANCE DETERMINATION EVALUATION

Comanche Peak Steam Electric Station
EDG Inoperability Caused By Painting Activities
Significance Determination Basis

1. **Phase 1 Screening Logic, Results, and Assumptions**

In accordance with NRC Inspection Manual Chapter 0612, Appendix B, "Issue Screening," the team determined that this finding represented a licensee performance deficiency. The team then determined that the issue was more than minor because it was associated with the equipment performance attribute and affected the mitigating systems cornerstone objective to ensure the availability, reliability, or function of a system or train in a mitigating system in that Emergency Diesel Generator DG-102 would not have started upon demand.

The team evaluated this finding using the "SDP Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones," provided in Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." For this finding, a Phase 2 estimation was required because the performance deficiency affected the emergency power supply system that is a support system for both mitigating and containment barrier systems.

2. **Phase 2 Risk Estimation**

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Phase 2 and Phase 3 Significance Determination of Reactor Inspection Findings for At-Power Situations," the senior reactor analyst evaluated the subject finding using the Risk-Informed Inspection Notebook for Comanche Peak Steam Electric Station, Units 1 and 2, Revision 2.01a. The following assumptions were made:

a. The identified performance deficiency occurred some time between the last successful test on October 24, 2007, and the test failure that occurred on November 21, 2007.

b. In accordance with Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules," Rule 1.1, "Exposure Time," the analyst determined the time frame over which the finding impacted the risk of plant operations. Because the exact time of failure was unknown, an exposure time of t/2 from the last valid test was used. This was ½ of the 28 days between tests, or 14 days. Therefore, for the phase 2 analysis, the exposure time used to represent the time that the performance deficiency affected plant risk was between 3 and 30 days.

c. Table 2 of the risk-informed notebook requires that when a performance deficiency affects the diesel generators, the following initiating event scenarios are applicable: LOOP and LEAC. Therefore, the analyst utilized these worksheets from the risk-informed notebook.

d. According to the risk-informed notebook, Table 1, for a 3-30 day exposure, the initiating event likelihood should be 3 for a loss of offsite power and 5 for a loss of offsite power with loss of one vital 6.9kV bus.

e. The analyst gave no operator action credit as discussed in Manual Chapter 0609, Appendix A, Attachment 1, Table 4, “Remaining Mitigation Capability Credit.” The requirements to have procedures in place and to have trained the operators in recovery under similar conditions for such credit were not met.

The dominant sequences from the notebook were documented below:

TABLE C.b
Failure of Emergency Diesel Generator 102 to Start
Phase 2 Sequences

Initiating Event	Sequence	Mitigating Functions	Results
Loss of Offsite Power	2	LOOP-AFW-FB	8
	4	LOOP-EAC-REC5	6
	7	LOOP-EAC-TDAFW	6
Loss of Offsite Power with Loss of One Vital 6.9 kV Bus	1	LEAC-PORV-HPR-MKRWST	8
	3	LEAC-PORV-HPI	7

Using the counting rule worksheet, the result from this estimation indicated that the finding was of low to moderate safety significance (WHITE). However, the analyst determined that this estimate did not include a full coverage of the risk related to the failure identified and that a better evaluation of the internal risk would be necessary for fully assessing the risk related to external initiators.

3. **Phase 3 Analysis**

In accordance with Manual Chapter 0609, Appendix A, the analyst performed a Phase 3 analysis using the Standardized Plant Analysis Risk (SPAR) Model for Comanche Peak, Revision 3.31, dated August 2006, to simulate the failed Diesel Generator 1-02. Additionally, the analyst conducted an assessment of the risk contributions from external initiators using insights and/or values provided by the licensee’s probabilistic risk assessment model, in the licensee’s recent submittal for extension of completion times for diesel generators (Reference 1), and simplified fire probabilistic risk assessment.

Reference 1: Letter dated November 15, 2007, Blevins to U.S. NRC, Subject: “Comanche Peak Steam Electric Station (CPSES) Docket Nos. 50-445 and 50-446, Response to Request for Additional Information Related to Licence Amendment Request (LAR) 06-009, Revision to Technical Specification (TS) 3.8.1, ‘AC Sources - Operating; Extension of Completion Times for Diesel Generators.”

Assumptions

To evaluate the change in risk caused by this performance deficiency, the analyst made the following assumptions:

A. The vital batteries at Comanche Peak will deplete after approximately 4 hours of full postaccident loads without an operating battery charger, assuming that operators do not take actions to shed unnecessary loads from the vital dc buses. This is the value used in the licensee's probabilistic risk assessment.

B. The Comanche Peak SPAR model, Revision 3.31, represents an appropriate tool for evaluation of the subject finding.

C. The failure of Emergency Diesel Generator 1-02 was the result of binding of the fuel rack on at least one injection pump that was caused by painting activities on and around the diesel.

D. Emergency Diesel Generator 1-02 successfully started and loaded during a surveillance performed on October 24, 2007. The diesel failed to start during a surveillance on November 21, 2007, because the fuel rack on at least one injection pump was bound to the extent that the entire fuel rack assembly was unable to leave the "no fuel" position.

E. Painting activities in and around the Emergency Diesel Generator 1-02 engine ended on November 1, 2007. Therefore, the conditions that caused the engine to fail had to have been in place at that time for the root cause to be valid (See Assumption C).

F. The exposure time used for evaluating this finding should be determined in accordance with Inspection Manual Chapter 0609, Appendix A, Attachment 2, "Site Specific Risk-Informed Inspection Notebook Usage Rules." Attachment 2 discusses the approach to establishing the exposure time that should be used for the significance determination process. Step 1.1 states:

    "The exposure time used in determining the initiating event likelihood should correspond to the time period that the condition being assessed is reasonably known to have existed. If the inception of the condition is unknown, then an exposure time of one half of the time period since the last successful demonstration of the component or function (*t/2*) should be used."

G. The appropriate exposure time (EXP), representing the time that Emergency Diesel Generator 1-02 was not functional, for use in this evaluation is 24 days.

    The exact time at which the residual paint that caused the binding of the fuel racks occurred is unknown. However, it is reasonable to assume that the condition existed after the completion of painting activities on November 1, 2007.

Therefore, in accordance with Assumption F, Emergency Diesel Generator 1-02 would not have started upon demand for the 20 days November 1 through November 21, 2007.

Additionally, the inception of the condition could have occurred any time between the last successful run of the machine on October 24 and the completion of the painting activities on November 1. Therefore, in accordance with Assumption F, Emergency Diesel Generator 1-02 would not have started upon demand for one half of the period from October 24 through November 1, or for an additional 4-day period.

Based on these two arguments, the analyst determined that the appropriate exposure time was the sum of the 20 days that the machine was reasonably assumed to have failed and one half the 8 day period that could have resulted in the failure condition.

H. Given the condition of the fuel rack and the interpretation by licensed operators of annunciator response procedures, operators would not have been able to recover Emergency Diesel Generator 1-02 prior to postulated core damage for sequences less than 2 hours. Licensed operators stated that the annunciator response procedure would not have directed operators to manipulate the fuel racks by hand nor does it require operators to request maintenance personnel perform such a task.

I. The appropriate nonrecovery probability for sequences longer than 2 hours is 0.29. The analyst conducted a human reliability analysis using the SPAR-H method to determine an appropriate nonrecovery probability. To calculate this value, the analyst used the following assumptions:

   a. The analyst assumed that nominal time was available for recovery diagnosis and action. The licensee recovered the diesel in 11 hours 11 minutes during nonemergency conditions. Therefore, the analyst assumed that, if required, recovery could have been reasonably performed within the 4 hour coping period plus extended boil down times.

   b. The analyst assumed that emergency response personnel would be under high stress during the diagnosis and recovery. This is based primarily on the belief that recovery personnel would know that the consequences of the task would represent a direct threat to plant safety.

   c. The complexity of this task was considered to be nominal. There is some ambiguity in the diagnosis. However, there are only two fundamental paths in diagnosis. The probability that the wrong path would be initially investigated is taken into account in the performance shaping factor for procedure quality.

   d. Procedures for the diagnosis were incomplete. Solely following the procedures available would not have led to recovery. The basic items to consider were available in the annunciator response procedure, although it is not clear that this procedure would have been governing and/or utilized by the recovery personnel.

e. All other performance shaping factors were considered nominal for obvious reasons.

J. Emergency Diesel Generator 1-01 would not have failed from the same cause as Emergency Diesel Generator 1-02 because painting activities had not been conducted on that diesel. Therefore, the analyst left the common cause failure probability at it's nominal value.

K. The nominal nonrecovery values used by the SPAR model are for the average nonrecovery for either of two diesel generators. Therefore, given that recovery of Emergency Diesel Generator 1-02 would be handled separately, the analyst adjusted the generic nonrecovery value to account for only Emergency Diesel Generator 1-01 being the only machine available for random failure recovery.

L. The nominal likelihood for a loss of offsite power was unaffected by the subject finding.

M. Evaluating the risk contribution of this finding related to seismic events is appropriately conducted by utilizing the licensee's assessment found in Reference 1. The conditional core damage frequency ($CCDF_{SEISMIC}$) given by the licensee was 2.1×10^{-6}/year.

N. The licensee's fire risk model is an appropriate tool for evaluation of the subject finding. The CCDF for fire ($CCDF_{FIRE}$) provided by the licensee in Reference 1 was 7.8×10^{-6}/year.

   The analyst independently evaluated the risk change related to internal fires. These insights were then used to challenge and evaluate the results of the licensee's model. In all cases, the licensee's model covered the scenarios posed by the analyst and included a larger scope of fires than was feasible for the analyst to evaluate.

O. Traditionally, the initiation of most high wind events, including those that cause a loss of offsite power, are included in the licensee's PRA and/or the SPAR model. However, the licensee's assessment in their individual plant evaluation for external events did not include events that damage other pieces of equipment that may affect risk. As stated in Reference 1, the licensee estimated the CCDF for tornados ($CCDF_{WIND}$) given the failure of a diesel generator to be 2.3×10^{-5}/year.

P. The best estimate of the risk contribution from the subject finding related to internal flooding is best evaluated using a ratio from the licensee's PRA as was discussed in Reference 1. In their evaluation, the licensee stated that the risk from internal flooding derived from their internal events PRA was approximately 1 percent (P_{FLOOD}) of the total plant core damage frequency.

Q. The ratio of sequences going to core damage in the first 2 hours to those going through battery depletion is the same for internal and external initiators. This assumption permits the analyst to use the ratio from the internal events SPAR in applying recovery to external initiators.

R. The differences between the SPAR and the licensee's models were inconsequential. The analyst, in reviewing the differences between the models, determined that there were several global differences including: the lack of random failure recovery for diesel generators in the licensee's model and the lack of convolution integrals in the SPAR model. However, the analyst determined that these differences were not of consequence to this evaluation because the final results were within the same color band.

<u>Internal Initiating Events</u>

The senior reactor analyst used the SPAR model for CPSES to estimate the change in risk associated with internal initiators that was caused by the finding. Average test and maintenance of modeled equipment was assumed and a cutset truncation of 1.0E-12 was used.

Consistent with guidance in the RASP Handbook, including NRC document, "Common-Cause Failure Analysis in Event Assessment (June 2007)," and Assumptions 3.C, 3.G, and 3.K, the SRA modeled the condition by adjusting the following basic events in the SPAR model:

Basic Event	Original Value	Conditional Value
EPS-DGN-FS-1EG1	5.0×10^{-3}	TRUE
EPS-XHE-XL-NR01H	7.72×10^{-1}	8.79×10^{-1}
EPS-XHE-XL-NR02H	6.48×10^{-1}	8.05×10^{-1}
EPS-XHE-XL-NR03H	5.56×10^{-1}	7.46×10^{-1}
EPS-XHE-XL-NR04H	4.84×10^{-1}	6.95×10^{-1}

The SPAR baseline core damage frequency (CDF_{BASE}) was 1.80×10^{-5}/year. The evaluation case for the above change set resulted in a conditional core damage frequency ($CCDF_{SPAR}$) of 3.78×10^{-4}/year. The dominant core damage sequences were documented in the table below:

Initiating Event	Sequence	Preponderant Failures	Frequency
Loss of Offsite Power	20-03	Failure of EDG 1-01 with Battery Depletion at 4 hours	2.62×10^{-4}/year
	20-06	Failure of EDG 1-01 with Battery Depletion at 4 hours combined with RCS Pump Seal Failure .	6.56×10^{-5}/year
	20-45	Failure of EDG 1-01 and the Turbine-Driven Auxiliary Feedwater Pump with Core Damage at 1 hour.	2.37×10^{-5}/year
	19	Failure of Motor and Turbine-Driven Auxiliary Feedwater Pumps and/or Operator Fails to Control.	1.07×10^{-5}/year

The change in incremental conditional core damage frequency (ICCDP) was calculated as follows:

$$ICCDF = CCDF_{SPAR} - CDF_{base}$$

$$= 3.78 \times 10^{-4}\text{/year} - 1.80 \times 10^{-5}\text{/year}$$

$$= 3.60 \times 10^{-4}\text{/year}$$

Given Assumptions 3.C through 3.G, the exposure time, representing the time that the performance deficiency impacted the plant, for this analysis was 24 days. Therefore, the change in core damage frequency (ΔCDF_{IntNR}) caused by this finding, without applying any recovery to the subject condition, and related to internal initiators was calculated as follows:

$$\Delta CDF_{IntNR} = ICCDF * EXP$$

$$= 3.60 \times 10^{-4}\text{/year} * (24 \text{ days} \div 365 \text{ days/year})$$

$$= 2.37 \times 10^{-5}$$

Given Assumption 3.H, the analyst determined that recovery credit for Emergency Diesel Generator 1-01 would not be provided for any sequence that led to core damage in less than 2 hours. Using utilities in the SAPHIRE software to slice cutsets by basic event, the analyst determined that 7.6 percent of all internal cutsets went to core damage in less than 2 hours (P_{SHORT}).

Given Assumption 3.I, the analyst applied a nonrecovery factor (P_{NR}) of 0.29 to all remaining cutsets. Therefore, the change in core damage frequency ($\Delta CDF_{Internal}$) caused by this finding and related to internal initiators was calculated as follows:

$$\Delta CDF_{Internal} = [\Delta CDF_{IntNR} * P_{SHORT}] + [\Delta CDF_{IntNR} * (1 - P_{SHORT}) * P_{NR}]$$

$$= [2.37 \times 10^{-5} * 0.076] + [2.37 \times 10^{-5} * (1 - 0.076) * 0.29]$$

$$= 8.15 \times 10^{-6}$$

<u>External Initiating Events</u>

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.2.5, "Screen for the Potential Risk Contribution Due to External Initiating Events," the analyst assessed the impact of external initiators on each of the findings, because the Phase 2 SDP result provided a Risk Significance Estimation of 7 or greater. The analyst determined that, for the risk of an external initiator to be impacted by this performance deficiency, the external event would have to cause a loss of offsite power that was not accounted for in the internal events model. Using the licensee's individual plant evaluation for external events and Reference 1, the analyst determined that the dominant sequences affected by the subject performance deficiency were from seismic events, high winds, fire, and internal flooding events.

A. Seismic Event Initiators

As discussed in Assumption 3.M, the analyst utilized the licensee's value for the affects on the risk of seismic events associated with a failed diesel generator. The incremental risk without recovery ($ICCDP_{SeisNR}$) was calculated as follows:

$$ICCDP_{SeisNR} = CCDF_{SEISMIC} * EXP$$

$$= 2.1 \times 10^{-6}/\text{year} * (24 \text{ days} \div 365 \text{ days/year})$$

$$= 1.38 \times 10^{-7}$$

Given Assumption 3.H and 3.Q, the analyst applied P_{SHORT} in quantifying the change in risk from seismic events.

Given Assumption 3.I, the analyst applied a nonrecovery factor (P_{NR}) of 0.29 to the remaining portion of the risk from seismic events. Therefore, the change in core damage frequency ($\Delta CDF_{SEISMIC}$) caused by this finding and related to seismic events was calculated as follows:

$$\Delta CDF_{SEISMIC} = [ICCDP_{SeisNR} * P_{SHORT}] + [ICCDP_{SeisNR} * (1 - P_{SHORT}) * P_{NR}]$$

$$= [1.38 \times 10^{-7} * 0.076] + [1.38 \times 10^{-7} * (1 - 0.076) * 0.29]$$

$$= 4.75 \times 10^{-8}$$

B. Internal Fire Initiators

As discussed in Assumption 3.N, the analyst utilized the licensee's value for the affects on the risk of internal fires associated with a failed diesel generator. The incremental risk without recovery ($ICCDP_{FireNR}$) was calculated as follows:

$$ICCDP_{FireNR} = CCDF_{FIRE} * EXP$$

$$= 7.8 \times 10^{-6}/year * (24 \text{ days} \div 365 \text{ days/year})$$

$$= 5.14 \times 10^{-7}$$

Given Assumption 3.H and 3.Q, the analyst applied P_{SHORT} in quantifying the change in risk from internal fires.

Given Assumption 3.I, the analyst applied a nonrecovery factor (P_{NR}) of 0.29 to the remaining portion of the risk from seismic events. Therefore, the change in core damage frequency (ΔCDF_{FIRE}) caused by this finding and related to seismic events was calculated as follows:

$$\Delta CDF_{FIRE} = [ICCDP_{FireNR} * P_{SHORT}] + [ICCDP_{FireNR} * (1 - P_{SHORT}) * P_{NR}]$$

$$= [5.14 \times 10^{-7} * 0.076] + [5.14 \times 10^{-7} * (1 - 0.076) * 0.29]$$

$$= 1.77 \times 10^{-7}$$

C. Tornados and High Wind Initiators

As discussed in Assumption 3.O, the analyst utilized the licensee's value for the affects on the risk of high wind events associated with a failed diesel generator. The incremental risk without recovery ($ICCDF_{WindNR}$) was calculated as follows:

$$ICCDP_{WindNR} = CCDF_{WIND} * EXP$$

$$= 2.1 \times 10^{-5}/year * (24 \text{ days} \div 365 \text{ days/year})$$

$$= 1.38 \times 10^{-6}$$

Given Assumption 3.H and 3.Q, the analyst applied P_{SHORT} in quantifying the change in risk from high wind events.

Given Assumption 3.I, the analyst applied a nonrecovery factor (P_{NR}) of 0.29 to the remaining portion of the risk from high wind events. Therefore, the change in core damage frequency (ΔCDF_{WIND}) caused by this finding and related to seismic events was calculated as follows:

$$\Delta CDF_{WIND} = [ICCDP_{WindNR} * P_{SHORT}] + [ICCDP_{WindNR} * (1 - P_{SHORT}) * P_{NR}]$$

$$= [1.38 \times 10^{-6} * 0.076] + [1.38 \times 10^{-6} * (1 - 0.076) * 0.29]$$

$$= 4.75 \times 10^{-7}$$

D. Internal Flooding Initiators

As discussed in Assumption 3.O, the analyst utilized the ratio determined by the licensee's PRA for internal flooding to other initiators. Given a value of 1 percent, the change in core damage frequency (ΔCDF_{FLOOD}) caused by this finding and related to internal flooding was calculated as follows:

$$\Delta CDF_{FLOOD} = \Delta CDF_{Internal} * P_{FLOOD}$$

$$= 8.15 \times 10^{-6} * 0.01$$

$$= 8.15 \times 10^{-8}$$

<u>Total Change in Core Damage Frequency</u>

Given that each of the initiators in this analysis were treated to ensure that the final probabilities were independent of each other, the analyst determined that he total change in core damage frequency (ΔCDF) could be calculated by taking the sum of each independent change. Therefore, the final Phase 3 result was calculated as follows:

$$\Delta CDF = \Delta CDF_{Internal} + \Delta CDF_{External}$$

$$= \Delta CDF_{Internal} + [\Delta CDF_{SEISMIC} + \Delta CDF_{FIRE} + \Delta CDF_{WIND} + \Delta CDF_{FLOOD}]$$

$$= 8.15 \times 10^{-6} + [4.75 \times 10^{-8} + 1.77 \times 10^{-7} + 4.75 \times 10^{-7} + 8.15 \times 10^{-8}]$$

$$= 8.93 \times 10^{-6}$$

This result indicated that the finding was of low to moderate significance to the risk of internal initiating events.

<u>Large Early Release Frequency Contribution</u>

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, Step 2.2.6, "Screen for the Potential Risk Contribution Due to LERF," the analyst assessed the impact on the large early release frequency because the Phase 2 SDP result provided a risk significance estimation of greater than 7.

Using NRC Inspection Manual Chapter 0609 Appendix H, "Containment Integrity Significance Determination Process," the senior reactor analyst determined that this was a Type A finding (i.e., a finding that can influence the likelihood of accidents leading to core damage that is also a LERF contributor). For a pressurized water reactor with a large, dry containment, like Comanche Peak Steam Electric Station, findings related to inter-system loss-of-coolant accidents and steam generator tube ruptures have the potential to impact LERF.

Appendix H, Table 5.1, "Phase 1 Screening - Type A Findings at Full Power," provides that station blackout scenarios and all other transients, including loss of offsite power initiators, screen out from further evaluation. These accident sequences are not considered to be significant to LERF. Therefore, the estimated ΔLERF was calculated to be less than 6.8×10^{-7}. Because the ΔLERF was less than the 1×10^{-6} White/Yellow threshold, the finding remains characterized as of low to moderate safety significance (White).