February 1, 2008

EA-07058

Mr. David A. Christian
President and Chief Nuclear Officer
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 2306-06711

SUBJECT: KEWAUNEE POWER STATION - NRC SUPPLEMENTAL INSPECTION REPORT 05000305/2007011

Dear Mr. Christian:

On December 19, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed a supplemental inspection pursuant to Inspection Procedure 95002, "Inspection for One Degraded Cornerstone or Any Three White Performance Inputs in a Strategic Performance Area," at your Kewaunee Power Station. The enclosed inspection report documents the inspection findings, which were discussed on December 19, 2007, with Mr. W. Matthews and other members of your staff.

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.

As discussed in our mid-cycle assessment letter dated August 31, 2007, plant performance for Kewaunee was categorized within the Degraded Cornerstone column of the Action Matrix of NRC Inspection Manual Chapter (IMC) 0305, "Operating Reactor Assessment Program," based on performance deficiencies in the Mitigating Systems Cornerstone. The findings involved: (1) a performance issue having substantial safety significance (Yellow) related to the failure to evaluate and repair a fuel oil leak on the 1A Emergency Diesel Generator (EDG), and (2) a White performance indicator for unplanned scrams per 7000 critical hours.

The specific purposes of the current inspection were to: (1) provide assurance that the root causes and contributing causes of risk significant performance issues were understood for individual and collective risk significant performance issues; (2) independently assess the extent of condition and the extent of cause for individual and collective risk significant performance issues; (3) independently determine if safety culture components caused or significantly contributed to the individual or collective risk significant performance issues; and (4) provide assurance that the licensee corrective actions to risk significant performance issues were sufficient to address the root causes and contributing causes, and to prevent recurrence.

As further detailed in the report, the inspectors concluded that adequate actions had been taken by Kewaunee Power Station to address the Yellow inspection finding and White performance indicator. As discussed in Section 06.01 of IMC 0305, safety significant inspection findings are carried forward for four calendar quarters or until appropriate licensee corrective actions have been completed, whichever is greater. Therefore, the Yellow inspection finding related to the failure to evaluate and repair a fuel oil leak on the 1A EDG, which was identified in the third quarter of 2006, will no longer be considered in the assessment process after the fourth quarter of 2007. The performance indicator for unplanned scrams will continue to be calculated per the guidance contained in Nuclear Energy Institute 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5.

Based on the results of this inspection, there were three NRC-identified findings of very low safety significance which involved violations of NRC requirements. In addition, one issue was reviewed under the NRC traditional enforcement process and determined to be a Severity Level IV violation of NRC requirements. However, because these violations were of very low safety significance and because the issues were entered into your corrective action program, the NRC is treating these violations as non-cited violations (NCVs), in accordance with Section VI.A.1 of the NRC Enforcement Policy.

If you contest these NCVs, 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 a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Kewaunee Power 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 System (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Cynthia D. Pederson, Director
Division of Reactor Projects

Docket No. 50-305
License No. DPR-43

Enclosure: Inspection Report 05000305/2007011
w/Attachment: Supplemental Information

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Cynthia D. Pederson, Director
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Letter to D. Christian from C. Pederson dated 02/01/2008

SUBJECT: KEWAUNEE POWER STATION - NRC SUPPLEMENTAL INSPECTION REPORT 05000305/2007011

cc w/encl:
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C. Funderburk, Director, Nuclear Licensing and Operations Support
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D. Zellner, Chairman, Town of Carlton
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Letter to D. Christian from C. Pederson dated 02/01/2008

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-305
License No:	DPR-43
Report No:	05000305/2007011
Licensee:	Dominion Energy Kewaunee, Inc.
Facility:	Kewaunee Power Station
Location:	Kewaunee, WI
Dates:	November 26 through December 19, 2007
Inspectors:	R. Orlikowski, Senior Resident Inspector, Duane Arnold S. Burgess, Senior Risk Analyst R. Daley, Senior Reactor Inspector J. Giessner, Resident Inspector, Palisades D. Betancourt-Roldan, Reactor Engineer (Observer)
Approved by:	M. Kunowski, Chief Branch 5 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000305/2007011; 10/26/2007 - 12/19/2007; Kewaunee Power Station; Supplemental Inspection 95002, Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area.

This report documents a supplemental inspection by NRC inspectors. The inspectors identified three Green findings and one Severity Level IV violation, all being treated as non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP 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 December 2006.

The NRC performed this supplemental inspection to assess the licensee's evaluation associated with the failure to evaluate and repair a fuel oil leak on the 1A emergency diesel generator (EDG) in June 2006. This performance issue was previously characterized as having substantial safety significance (Yellow) in NRC Inspection Report 05000305/2007007. During this supplemental inspection, performed in accordance with Inspection Procedure 95002, "Inspection for One Degraded Cornerstone or Any Three White Performance Inputs in a Strategic Performance Area," the inspectors determined that the root cause evaluation appeared thorough, and the evaluation appropriately evaluated the root and contributing causes, addressed the extent of condition/cause, assessed safety culture, and established corrective actions for risk significant performance issues that were sufficient to address the causes and prevent recurrence. The root causes identified by the licensee were (1) the tolerance in station processes of minor leaks on risk significant systems, and (2) station management systems have allowed equipment deficiencies to exist.

In addition, the inspectors assessed the licensee's evaluation associated with the performance indicator for unplanned scrams per 7000 critical hours. This performance indicator was characterized as having low to moderate risk significance (White) from the fourth quarter of 2006 to the third quarter of 2007. During this supplemental inspection, the inspectors determined that the individual root cause evaluations for the five scrams that caused the indicator to change to White and the associated common cause evaluation appeared thorough, and these evaluations appropriately evaluated the root and contributing causes, addressed the extent of condition/cause, assessed safety culture, and established corrective actions for risk significant performance issues that were sufficient to address the causes and prevent recurrence.

Given the licensee's acceptable performance in addressing the 1A EDG issue and the lapse of four calendar quarters since the issue was identified, the Yellow inspection finding associated with it will no longer be considered in the assessment process after the 4th quarter of 2007. Also, given the licensee's acceptable performance in addressing the White performance indicator, the indicator will only be considered in assessing plant performance for the quarters in which the licensee reported it as White, in accordance with the guidance in IMC 0305, "Operating Reactor Assessment Program."

a. **NRC-Identified and Self-Revealing Findings**

Cornerstone: Mitigating Systems

- Green. The inspections identified a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," of very low safety significance. Specifically, the licensee failed to initiate corrective action documents in accordance with plant procedures for multiple leaks found in the plant. The licensee entered this item into its corrective action program.

  The finding is greater than minor because it was associated with the equipment performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to identify and correct leakage on equipment important to safety could eventually lead to equipment unavailability during events that the equipment is designed to mitigate. The finding is of very low safety significance (Green), because the inspectors answered "no" to all five questions under the Mitigating Systems Cornerstone column of the Phase 1 worksheet in Inspection Manual Chapter 0609, "Significance Determination Process." Specifically, at the time that the leakage was discovered, none of the leaks immediately impacted the functionality of the equipment affected. The finding has a cross-cutting aspect in the area of human performance because the licensee failed to effectively communicate expectations regarding procedural compliance for the corrective action program (H.4.b). (Section 4.3.b)

- Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," of very low safety significance, for failure by the licensee to follow procedural requirements for performing an adequate extent of condition for a diesel fuel line failure in 2006. Specifically, the licensee failed to complete an extent of condition which would have evaluated different systems where a similar failure mechanism (cyclic fatigue) could occur. The licensee entered the item into its corrective action program.

  The issue is greater than minor because it was associated with the equipment performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability of systems that respond to initiating events to prevent undesirable consequences. Specifically, it affected the equipment performance attribute for availability and reliability. Using Inspection Manual Chapter 0609, "Significance Determination Process," the inspectors screened this issue as being of very low safety significance (Green) because no loss of safety function occurred. (Section 4.3.a)

- Green. The inspectors identified a non-cited violation of 10 CFR 50.71, of very low safety significance, for the licensee's failure to update the Updated Safety Analysis Report (USAR). Specifically, the licensee failed to update the USAR to fully reflect the results of a safety analysis performed in response to Generic Letter 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." The licensee entered this issue into its corrective action program.

Because this finding potentially impacted the NRC's ability to perform its regulatory function, it was evaluated using the traditional enforcement process. The finding is greater than minor because the failure to provide complete licensing and design basis information in the USAR could result in either the licensee making an inappropriate licensing interpretation or the NRC making an inappropriate regulatory decision based on incomplete information in the USAR. NRC management determined that this issue is of very low safety significance (Green) because it is a design issue confirmed not to result in a loss of operability. (Section 4.3.c)

- Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," of very low safety significance, for failure by the licensee to follow procedural requirements for performing an adequate extent of condition following relay failures that led to reactor trips in 2006 and 2007. Specifically, the licensee failed to perform an extent of condition action to inspect Engineered Safety Feature (ESF) relays when sufficient causal evidence was present that the same style relay in the ESF system (BF-66 relays) were susceptible to sulfidation, installation deficiencies, or manufacturing defects. The licensee entered this issue into its corrective action program.

  The issue is greater than minor because, if left uncorrected, the failure to assess the other systems would become a more significant safety concern. Using Inspection Manual Chapter 0609, "Significance Determination Process," the inspectors screened this issue as being of very low safety significance (Green) because no loss of safety function occurred. (Section 5.3.a)

b. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

1. INSPECTION SCOPE

This inspection was conducted in accordance with Inspection Procedure (IP) 95002, "Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area," to assess the licensee's evaluation of one White Performance Indicator (PI) and one Yellow inspection finding in the Mitigating Systems Cornerstone. The inspection objectives were to:

- Provide assurance that the root causes and contributing causes of risk significant performance issues are understood for individual and collective risk significant performance issues;

- Independently assess the extent of condition and the extent of cause for individual and collective risk significant performance issues;

- Independently determine if safety culture components caused or significantly contributed to the individual or collective risk significant performance issues; and

- Provide assurance that the licensee corrective actions to risk significant performance issues are sufficient to address the root causes and contributing causes, and to prevent recurrence.

Kewaunee entered the Degraded Cornerstone column of NRC's Action Matrix in the first quarter of 2007 as a result of one inspection finding of substantial safety significance (Yellow) within the Mitigating Systems Cornerstone. At the time, the licensee was in the Regulatory Response column of the Action Matrix due to a White PI for Unplanned Scrams per 7000 Critical Hours in the Initiating Events Cornerstone. The PI turned White in the fourth quarter of 2006. The Yellow inspection finding was discussed in detail in Inspection Report (IR) 05000305/2006004 and the final safety significance determination was documented in IR 05000305/2007007.

2. EVALUATION OF INSPECTION REQUIREMENTS

Yellow Inspection Finding: Failure to Identify and Repair a Fuel Oil Leak on the 1A Emergency Diesel Generator (EDG)

.1 <u>Problem Identification</u>

a. *Determine whether the licensee's root cause evaluation specified who identified the issue and under what conditions the issue was identified.*

The licensee identified this issue. The licensee originally discovered a fitting on the 1A EDG was leaking fuel oil on June 25, 2006. Identification of the issue as an equipment deficiency was determined on June 28. The EDG was eventually declared to be out-of-service due to excessive leakage on August 17. The licensee identified that it failed to write a CAP (Corrective Action Program document) for this issue. This failure dated back to June 28, when the issue was originally identified as an equipment deficiency.

The inspectors determined that the licensee appropriately identified who and under what conditions the issue was identified.

b. *Determine whether the licensee's root cause evaluation documented how long the issue existed, and whether there were any prior opportunities for identification.*

The failure to document the 1A EDG fuel leak in the corrective action program dated back to June 28, 2006, when the issue was originally identified as an equipment deficiency. The licensee determined that work requests concerning the fitting were initiated on June 25 and June 28. Excessive leakage was determined to exist on August 17, when the licensee declared the 1A EDG inoperable.

The inspectors determined that the licensee's evaluation did document how long the issue existed.

c. *Determine whether the licensee's root cause evaluation documented the plant specific risk consequences and compliance concerns associated with the issue.*

This issue was classified as a "Yellow" finding and the Root Cause Evaluation (RCE-2006-0736, Revision 7 (RCE-736)) also documented that the finding associated with this issue was a "Yellow" finding.

Additionally, the licensee documented that the consequences of not writing a CAP and fixing the fuel leak on the 1A EDG included:

- Unscheduled emergent maintenance;
- Entry into a Technical Specification Action Statement;
- A Yellow inspection finding from the NRC;
- Increase in counted "unavailability" time for equipment Maintenance Rule and Performance Indicators; and
- Change in Core Damage Frequency of 8.5E-5/year.

The licensee also documented that the significance of the event was the removal of one of two safety system power sources, decreased system availability, increase in core damage probability frequency, and additional Maintenance Rule out-of-service time. Based upon the above documented observations, the inspectors concluded that the licensee appropriately documented the risk consequences and compliance concerns associated with the issue.

.2 Root Cause, Extent of Condition, and Extent of Cause

a. *Determine whether the licensee's root cause evaluation applied systematic methods in evaluating the issue in order to identify root causes and contributing causes.*

In its root cause analysis, the licensee used the following systematic methods:

- Data gathering through interviews and document review;
- Timeline construction;
- Events and Causal Factor Charting;
- Barrier Analysis;
- Causal Factors Tree; and

- Fault Tree Analysis.

In RCE-736, the licensee used both a Failure Modes Analysis and Barrier Analysis to evaluate these human performance issues. Based upon this, the inspectors determined that the methods used to evaluate the root and contributing causes were adequate.

b. *Determine whether the licensee's root cause evaluation was conducted to a level of detail commensurate with the significance of the problem.*

The RCE was thorough. Root causes identified by the licensee in its evaluation included the following:

- Kewaunee Power Station (KPS) processes allowed for tolerance of minor leaks on risk significant systems; and
- Management systems have allowed for equipment deficiencies to exist at KPS.

Contributing causes include:

- Management expectations are not effectively implemented related to CAP initiation for equipment deficiencies; and
- Operating experience (OE) was not evaluated for generic implications.

As stated in Section 2.2.a, the RCE included an extensive timeline of events and an event and causal factor tree.

The licensee also identified that neither the Shift Manager nor the Shift Technical Advisor prompted the Nuclear Licensed Operator who had discovered the fuel leaks to write a CAP. The licensee determined that this was a failure to embrace management expectations for procedural compliance.

Based upon the extensive work performed for this root cause, the inspectors concluded that the root cause evaluation was conducted to a level of detail commensurate with the significance of the problem.

c. *Determine whether the licensee's root cause evaluation included consideration of prior occurrences of the problem and knowledge of prior operating experience.*

The RCE included a dedicated section (Section 2.4) entitled, "Operating Experience: (Internal and External)." This section considered both prior occurrences and OE. As a result of this review, the licensee determined that while there was not any OE that pertained exactly to the type of leaking that occurred on the 1A EDG, there was OE that, if it had been screened generically, could have heightened knowledge associated with this type of fuel leakage. The licensee further determined that a large amount of OE was sent out to plant personnel as FYI ("For Your Information"), with no action or response required. The licensee further concluded that "the lack of a robust OE program allows OE closure while discounting review for generic implications of failures on other equipment and possible common causes."

Based upon this review, the licensee was able to make numerous conclusions regarding weaknesses in its OE program. Some of the more pertinent conclusions included:

- There was no process for handling or assessing FYI information;
- Many of the OE items were evaluated as FYI that should have been evaluated for generic implications;
- FYI items often underwent only cursory reviews; and
- Equipment issues for risk significant systems were not captured in the corrective action program and therefore could not be further evaluated or available for future internal OE searches.

In addition, the licensee performed a common cause analysis. This analysis, RCE 2007-041, evaluated the commonalities of the five recent unplanned scrams at KPS and the EDG fuel oil issue.

The inspectors concluded that the RCE included a consideration of prior occurrences of the problem and knowledge of prior operating experience.

d. *Determine whether the licensee's root cause evaluation addressed extent of condition and extent of cause of the problem.*

The licensee did perform an extent of condition review, contained in Section 2.5, Extent of Condition, of RCE-736. The extent of condition addressed the following concerns/questions regarding the failure to write a CAP:

- What other CAPs were not written by the individual on that shift?
- What other significant open equipment deficiencies did not have a CAP written against them?
- What other areas were impacted in a cross-cutting manner similar to the CAP?

In addition, as already stated, the licensee performed a common cause analysis which evaluated the extent of commonality of the five recent unplanned scrams at KPS and the EDG fuel oil issue. This common cause analysis also assigned corrective actions for the causes associated with these issues.

Additionally, since there was a recognition that there were safety culture aspects associated with the issue, the licensee initiated a Common Cause Action (CCA) in RCE-736 to conduct collective reviews of the past two safety culture assessments, a problem identification and resolution (PI&R) self-assessment, and the safety culture issues associated with the IP 95001 and IP 95002 root cause analyses. The CCA involved the initiation of Condition Report (CR) 016651 which resulted in Safety Culture Self-Assessment (SAR) 000310. This SAR contained additional corrective actions and effectiveness reviews associated with safety culture issues at KPS.

The inspectors concluded that the RCE addressed extent of condition and extent of cause concerns.

.3 <u>Corrective Action</u>

a. *Determine whether the licensee specified appropriate corrective actions for each common or root cause or that the licensee evaluated why no actions were necessary.*

The corrective actions appear to be appropriate for the major items addressed in the RCE. The root causes, as listed in RCE-736, were the following:

- KPS processes allowed for tolerance of minor leaks on risk significant systems; and
- Management systems have allowed for equipment deficiencies to exist at KPS.

Contributing causes were as follows:

- Management expectations were not effectively implemented on CAP initiation for equipment deficiencies; and
- OE was not evaluated for generic implications.

For each case, the licensee has addressed each root/contributing cause with specific corrective action(s). These corrective actions are located in Section 1.5 of RCE-736.

The first contributing cause addressed the failure to effectively write a CAP. The long-term corrective action directly associated with this contributing cause was to implement the MAXIMO work management program. The MAXIMO system requires that a CAP be written and entered into the computer system before a work order (WO) can be generated. Prior to the implementation of MAXIMO, equipment deficiencies could be corrected by the initiation of a WO. Procedurally, a CAP should have been initiated along with the WO; however, it was possible for a deficiency to be corrected without a CAP ever being initiated. This was the case for the fuel oil leakage issue. With MAXIMO, the WO cannot be issued without an associated CAP.

Additionally, as previously stated, RCE000736 initiated CCA-1 recommended collective reviews of the past two safety culture assessments, a PI&R self-assessment, and the safety culture issues associated with the IP 95001 and IP 95002 root cause analyses. The CCA involved the initiation of CR 016651, which resulted in Safety Culture Self-Assessment SAR-000310.

SAR-000310 addressed the underlying and most dominant aspect of the root cause for the fuel oil leak issue - safety culture, the accountability component. The licensee, and the NRC inspectors, recognized that the underlying reason why management expectations were not being effectively implemented for CAP initiation for equipment deficiencies was due to the safety culture at Kewaunee. The Safety Culture Self-Assessment, documented the action plan to address these safety culture issues and, ultimately, the primary reason for the failure to initiate a CAP for the fuel oil leak.

SAR-000310 identified a number of areas for improvement (AFIs). These included the corrective action program, selection and communication of station priorities, proper management alignment of priorities, accountability, and communications. A number of corrective actions were initiated for each of these AFIs. The corrective actions were entered into and tracked for completion by the licensee’s corrective action program.

b. *Determine whether the licensee prioritized the corrective actions with consideration of the risk significance and regulatory compliance.*

The corrective actions were prioritized based upon the KPS guidance in procedure PI-KW-200, Corrective Action. The corrective action items were either prioritized as High, Medium, or Low. In accordance with PI-KW-200, this prioritization considered both licensing/regulatory performance and nuclear safety.

Based upon the guidance in PI-W-200, and the prioritization of the corrective actions in accordance with this procedure, the inspectors determined that the corrective actions had been prioritized with consideration of the risk significance and regulatory compliance.

c. *Determine whether the licensee established a schedule for implementing and completing the corrective actions.*

Due dates for corrective actions were established. RCE-736 and SAR-000310 contained some of these dates; however, many of the due dates for the action items were contained in the licensee's corrective action program. The inspectors were provided a matrix that showed each corrective action item and the dates for completion for each of these actions. This matrix showed that the latest due date for any of these corrective actions was August 31, 2008. As a result, the inspectors were able to determine that a schedule had been established for implementing and completing the corrective actions.

d. *Determine whether the licensee developed quantitative or qualitative measures of success for determining effectiveness of corrective actions to prevent recurrence.*

When the inspectors started the inspection, it was unclear how the licensee was going to implement an effectiveness review, because little was documented in that regard, particularly in relation to safety culture issues which constituted the majority of the corrective actions to be accomplished. From discussions with the licensee, the inspectors were able to determine that the licensee planned to perform effectiveness reviews of the safety culture corrective actions in SAR-000310 when it performed its mid-cycle and end-of-2008 safety culture assessments. However, the inspectors were concerned because there was nothing in place to ensure that this effectiveness review was performed. The licensee subsequently entered Corrective Action (CA) items into its corrective action program to ensure that these effectiveness reviews were performed as an integral part of future safety culture assessments and surveys.

Consequently, the inspectors determined that quantitative or qualitative measures of success had been developed for determining the effectiveness of the corrective actions to prevent recurrence.

3. EVALUATION OF INSPECTION REQUIREMENTS

White Performance Indicator: Unplanned Scrams per 7000 Critical Hours

.1 Problem Identification

a. *Determine whether the licensee's root cause evaluation specified who identified the issue and under what conditions the issue was identified.*

Each of the licensee's RCEs for the five unplanned trips identified who identified the issue and under what conditions. Specifically, the licensee identified that each of the issues were self-revealing due to the unplanned trips (either a manual trip or an automatic trip) and described the conditions that existed prior to the unplanned trip. This area was considered acceptable.

b. *Determine whether the licensee's root cause evaluation documented how long the issue existed, and whether there were any prior opportunities for identification.*

Each of the licensee's RCEs for the five unplanned trips documented how long the condition, which caused each reactor trip, existed, and any prior opportunities for identification. Specifically, the licensee identified that prior opportunity did exist to detect Mechanically Operated Contact (MOC) switch set-up issues that caused the reactor trip on April 26, 2006. The licensee did not identify any prior opportunities to identify the other issues that caused the other reactor trips. This area was considered acceptable.

c. *Determine whether the licensee's root cause evaluation documented the plant specific risk consequences and compliance concerns associated with the issue.*

The licensee's RCE documented the plant-specific risk consequences and compliance concerns associated with the issues. In all cases, there were no safety consequences to the plant or public health during the plant trips. However, the reactor trip that occurred on April 26, 2006, revealed to the licensee that its previous operational philosophy did not include adding the allowable equipment Technical Specification Limiting Condition for Operation (TS LCO) time to the time requirement to achieve shutdown. Therefore, the licensee incorrectly believed they needed to be in hot shutdown 6 hours from when the shutdown was commenced, when there actually was a total of 79 hours to be in hot shutdown from when the equipment was declared inoperable. Although there was no compliance concern, this shortened time was considered a contributing factor to the plant trip. The licensee now appropriately combines the equipment LCO time with the other LCO times for shutting down the plant. This area was considered acceptable.

.2 Root Cause, Extent of Condition, and Extent of Cause

a. *Determine whether the licensee's root cause evaluation applied systematic methods in evaluating the issue in order to identify root causes and contributing causes.*

The licensee's RCEs applied systematic methods in evaluating each issue associated with the five reactor trips. Some or all of the following methods were used:

- Event and Causal Factor Analysis;
- Why Analysis;

- Fishbone Analysis;
- Failure Mode Analysis (internal and external); and
- Comparative Time Line.

The methods were considered to be systematic as they employed root cause methods that were recognized and discussed in the Dominion root cause guidance documents.

This area was considered satisfactory in regard to the methods employed. However, the extent of condition for the first reactor trip caused by a relay failure in the Reactor Protection System (RPS) trip matrix associated with the nuclear instrumentation (RCE-745) was recognized by the licensee as being inadequate since another reactor trip occurred for a similar relay failure (RCE-757) about three months later. This is further discussed in Section 5.3.a. of this inspection report.

b. *Determine whether the licensee's root cause evaluation was conducted to a level of detail commensurate with the significance of the problem.*

The licensee's RCEs for the five reactor trips were conducted to a level of detail commensurate with the significance of the problems that caused the reactor trips, with one exception. RCE-745 documented a plant trip that occurred on November 10, 2006, due to a relay failure in the RPS trip matrix associated with nuclear instrumentation. After RCE-745 was issued, the plant tripped again on February 27, 2007, due to another relay failure during surveillance on the nuclear instrumentation. The licensee agreed that RCE-745 was inadequate in addressing the root cause or that corrective action were untimely. RCE-757 was completed and superceded RCE-745. The inspectors concluded that the new root causes, contributing causes, and the corrective actions identified in RCE-757 better addressed and appropriately bounded the issue of the relays failures. The inspectors determined that this area was acceptable.

c. *Determine whether the licensee's root cause evaluation included consideration of prior occurrences of the problem and knowledge of prior operating experience.*

The licensee's RCEs for the five reactor trips included consideration of prior occurrences of the problem and acknowledged prior OE, both internal and external. The inspectors determined that this area was acceptable.

d. *Determine whether the licensee's root cause evaluation addressed extent of condition and extent of cause of the problem.*

The inspectors determined that the licensee had addressed the extent of condition of each of the five reactor trips and had taken steps to address preventing reactor trips, in general, by implementing a single-point vulnerability (SPV) project. An SPV was defined as any single component (electrical, control, or mechanical) that by failure would cause an automatic or manual reactor trip, or a condition that procedurally directed a reactor trip or caused the plant to enter into a short duration TS LCO. The first phase began in July 2007 and included review of the rod control system, turbine, main feedwater, and the main generator/switchyard. Phase 1 resulted in the identification and elimination of many SPVs through system modifications.

The inspectors identified only one instance where the extent of condition for the reactor trip on January 12, 2007, was too narrowly focused. See Section 5.2.a.(1) for further details. Overall, this area was considered to be acceptable.

.3 Corrective Action

a. *Determine whether the licensee specified appropriate corrective actions for each common or root cause or that the licensee evaluated why no actions were necessary.*

The licensee took a number of immediate corrective actions to resolve the causes of the five reactor trips. These corrective actions were reviewed prior to each restart. As discussed in Section 3.2.b, the corrective actions for RCE-745 were inadequate and another reactor trip occurred three months later from similar equipment issues. In general, the inspectors determined that appropriate corrective actions for each root cause were taken. This area is considered acceptable.

b. *Determine whether the licensee prioritized the corrective actions with consideration of the risk significance and regulatory compliance.*

The licensee’s corrective actions appeared to be prioritized with consideration of the risk significance and regulatory compliance, in that, those corrective actions necessary to reduce risk and restore compliance were implemented immediately.

c. *Determine whether the licensee established a schedule for implementing and completing the corrective actions.*

The licensee established a reasonable schedule for implementing and completing the corrective actions; however, all the interim actions for the October 30, 2006, reactor trip due to the loss of the red instrument bus during inverter maintenance (RCE-38) were not properly implemented. This is discussed further in Section 5.2.a.(2). Other than that one instance, the inspectors did not identify any issues of significance. This area is acceptable.

d. *Determine whether the licensee developed quantitative or qualitative measures of success for determining effectiveness of corrective actions to prevent recurrence.*

For each of the five reactor trips, the inspectors concluded that corrective actions taken were realistic, timely, measurable, incorporated feedback, and had appropriate standards/criteria to measure effectiveness. The SPV program was also considered to be an effective tool to identify and prevent reactor trips. This area was considered acceptable.

4. INDEPENDENT ASSESSMENT OF EXTENT OF CONDITION AND EXTENT OF CAUSE

Yellow Inspection Finding: Failure to Identify and Repair a Fuel Oil Leak on the 1A EDG

.1 Inspection Scope

The inspectors independently assessed the validity of the licensee's conclusions regarding the extent of condition and extent of cause of the issues. The inspectors used casual factors developed from the Management Oversight and Risk Tree (MORT) methodology and reviewed those against the licensee's evaluation and extent of condition/cause. The inspectors then reviewed licensee records, procedures, and documents; conducted detailed interviews; and reviewed plant evolutions in progress to assess and evaluate the extent of condition and extent of cause of the issues. The method of analysis included the use of NRC baseline inspection procedures, for example, IP 71111.15 for reviewing operability evaluations, IP 71152 for reviewing the effectiveness of corrective action programs, or IP 71111.22 for reviewing surveillance procedures. Finally, the results were compared to the licensee's assessments and any differences noted were discussed with the licensee and evaluated using the SDP process. The inspectors reviewed these event-based issues and conducted an independent assessment for these issues that led to the Yellow inspection finding for the 1A EDG fuel leak:

- RCE-736 – EDG 1A Fuel Oil Fitting Leak
  (unavailable June 29, 2007-August 17, 2007)

In addition to the normal corrective action documents and logs, the inspectors reviewed the following documents:

- RCE-41 - Common Cause;
- RCE-39 - Substantive Crosscutting Issue in the Area of Human Performance, and;
- RCE-40 - NRC Identified Crosscutting Issues Remain Open in the Area of PI&R.

.2 Assessments and Observations

a. Extent of Condition

Observations: The extent of condition was not timely, was narrow in scope, and did not prevent a similar occurrence on a Technical Support Center Diesel Generator (TSC DG). In June 2006, a leak of one drop per minute (dpm) was found on the 1A EDG fuel line. In addition to the operator, other shift personnel knew of the issue, but no CR was written. In August, a surveillance run of the 1A EDG was stopped due to the leak becoming larger and rendering the EDG inoperable. The root cause was the failure of tubing at a fitting due to cyclic fatigue. The original extent of condition did not look at other possible, susceptible fittings/tubing. In December 2006, a similar failure (small bore pipe and cyclic failure) occurred on a pipe nipple for the TSC DG. A previous cyclic failure in 2005 occurred on the TSC DG, but on a different small bore pipe. Apparent

Cause Evaluation (ACE) 3353 added an action to inspect EDG piping as part of the TSC DG extent of condition. In February 2007, nuclear oversight (NOS, quality assurance) wrote a CR that indicated that an extent of condition was not done for the RCE-736 material failure. A thorough walkdown was not done until mid-2007, and then the extent of condition only looked at diesels. No other systems were reviewed during the walkdown, although the plant has rotating equipment and vibration induced flow forces in other plant systems.

Assessment: The inspectors conducted a walkdown to identify if other leaks existed and if other fittings had signs of leakage. The walkdown included approximately 100 fittings (on EDGs and the safety injection, containment spray, and charging systems) and found indications of approximately 10 leaks (oil, dry boric acid, or other chemical residue). Consequently, the licensee wrote CR 025736 and CR 025734. Although none of these leaks impacted the operability of the supported equipment, the inspectors concluded the extent of condition should be a thorough review for possible fatigue failure. The inspectors concluded this was a performance deficiency and is addressed as a finding in Section 4.3.b. In addition, the inspectors watched the performance of the 1B EDG surveillance testing, including manual barring, relay testing, and loading the diesel to accident loads. The inspectors monitored the human performance of operations and maintenance staff during these evolutions. The inspectors also independently inspected the 1B EDG for leaks. No findings of significance were noted.

b. Extent of Cause

Observations: The extent of cause did not look at operators' performance in evaluating operability. RCE-736 did not evaluate the need to improve plant staff knowledge of operability. This would have been appropriate since at least two licensed operators and a system engineer would not have considered operability an issue with a minor leak from the type of fitting on the 1A EDG that leaked in June 2006, even if a CR were written. The subtle, yet crucial, piece of data was that a leaky fitting - even when the leak was as low as 1 dpm - must be assessed for its ability to fulfill its supported equipment mission. Therefore, possible failure modes need to be assessed, for example, cyclic fatigue, bolt relaxation for torqued bolts, or rate of change for fluid leaks in the Emergency Core Cooling System (ECCS) boundary. These concepts were not discussed in the evaluation, but would be crucial to prevent recurrence of the issue. The licensee's action from other events included training and sensitivity to leaks, but without a link to the RCE, actions may not be continuing in nature and address long-term operations' performance. The licensee wrote CR 26704 to address this issue. The inspectors sampled recent CRs during the inspection weeks and included leak evaluation in those samples. The inspectors found no issues of significance, and concluded the operations staff was currently performing reasonable operability assessments. The inspectors also discussed with the licensee the need for continuing training to plant personnel on operability.

For the fuel leak, the fitting failed from cyclic fatigue. No records could be found that indicated the fitting had been damaged or overstressed. As part of the root cause assessment, the inspectors reviewed modifications and the mechanical WO history for the 1A EDG for the last ten years. Recent modifications that could have had an impact on the operation of the EDG were reviewed to determine if the changes had been properly evaluated. The inspectors also performed a search of WOs for the EDGs. In general it can be said that the WOs associated with leaks have increased since 2006.

This could be due to the licensee's goal of not tolerating leaks. The inspectors reviewed the work package PM70-610, System 10 DGM Twelve Year Inspection, from 2001. After reviewing the package, the inspectors found no issues, but noted that the quality was weak since it only had a general overview of all the work done and it did not describe how and why equipment was replaced or conditions that were observed during the course of the maintenance. For example, an oil pump was replaced, but the reason for this replacement, how it was replaced (disassembled), or the as-found condition was not documented.

The inspectors also noted that there was no analysis completed of whether the old material would have had adequate endurance based on the installed condition, using normal maintenance practices. Knowing if the existing material would be rated acceptably could lead to another root cause (such as, the fitting was overstressed during some activity). This causal analysis may have provided an opportunity to evaluate maintenance or configuration control work practices. Because there was an existing WO to change out the fuel oil pumps in 2001, it was reasonable to conclude, based on proximity, that the fitting that failed in 2006 was disassembled in 2001. As discussed above, the diesel overhaul procedure used in 2001 for the 12-year inspection was very limited on detail and could not be used to determine how the equipment was disassembled and reassembled. There were no detailed interviews or investigations to evaluate the performance of the maintenance or the quality of their configuration procedures. The change-out of material from copper to stainless steel did change the endurance curves and make the fitting less susceptible to cyclic fatigue. Yet, there was no evidence that copper was the wrong material. Finally, not having a detailed assessment that the new stainless steel piping would be acceptable could lead to a similar failure without a periodic preventive maintenance (PM) program for change out of the fitting. The inspectors discussed these observations with the licensee who wrote CR 027045 to evaluate whether any further action was needed.

.3 Findings

a. 1A EDG Fuel Line Leak Extent of Condition

Introduction: The inspectors identified a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," of very low safety significance (Green), for the failure by the licensee to follow procedural requirements for performing an adequate extent of condition for the 1A EDG fuel line failure in 2006. Specifically, the licensee failed to complete an extent of condition that would have evaluated different systems where a similar failure mechanism (cyclic fatigue) could occur.

Description: In June 2006, a leak of one dpm was found on the 1A EDG fuel line. In addition to an operator, other shift personnel knew of the issue, but no CR was written. In August, a surveillance run of the 1A EDG was stopped because the leak increased and the licensee declared the EDG inoperable. The root cause of the equipment failure was the failure of tubing due to cyclic fatigue (RCE-736). The original extent of condition did not look at any other possible, susceptible tubing. In December 2006, a similar failure (cyclic fatigue) occurred on a pipe nipple for the TSC DG, a piece of nonsafety-related equipment with an augmented quality function. A review of WOs indicated that a cyclic fatigue failure had also occurred on the TSC DG in 2005. In February 2007, NOS wrote a CR that indicated that an extent of condition was not done for the equipment failure issue. A self-assessment performed in July 2007 indicated the extent of condition was not acceptable. When systems were finally walked down, only diesel systems were reviewed; no other susceptible systems were reviewed. The inspectors inquired why no other systems were reviewed and the licensee indicated that the action was considered, but it seemed appropriate to have more informal reviews by the individual system engineers as part of their normal routine. Since other systems could be impacted, the inspectors walked down fittings of components of small piping where cyclic fatigue could occur. The inspectors found several indications of leaks (dried boric acid or chemical residue) where no CR was written. However, the inspectors did not find any indication of a leak which would have impacted operability.

The inspectors reviewed the evaluation procedure the site used to conduct extent of condition reviews for adverse conditions to quality. Station procedure PI-AA-300, Cause Evaluation, stated that susceptible material or equipment in other plant systems shall be inspected when sufficient causal evidence is present. The TSC DG was not inspected during an extent of condition review, and a similar failure occurred on the TSC DG approximately six months later. Also, the extent of condition review that was performed focused only on diesel generators and not on other systems that could be affected. The inspectors concluded the failure to conduct an adequate extent of condition was within the licensee's ability to foresee and correct.

Analysis: The failure to inspect other plant equipment, including the TSC DG, for extent of condition assessment was determined to be a performance deficiency warranting further review. The inspectors concluded that the finding is greater than minor in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 20, 2007, in that the finding is associated with the equipment performance attribute of the Mitigating System Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, it affected the equipment performance attribute for availability and reliability. The finding screened as having very low significance (Green) using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for the At-Power Situations," dated January 10, 2008, because no loss of safety function occurred.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed and accomplished by procedures appropriate to the circumstances. Section 3.2.7 of station procedure PI-AA-300, a quality procedure, required that susceptible material or equipment be inspected when sufficient causal evidence was present. Contrary to this, the licensee failed to conduct an adequate extent of condition review when a fuel line leak occurred due to cyclic fatigue in mid-2006. Because this finding was of very low safety significance and because the finding was entered into the licensee's corrective action program as CR 025716, this violation is being treated as an NCV (NCV 0500305/2007011-01), consistent with Section VI.A of the NRC Enforcement Policy.

b. Failure to Initiate Corrective Action Documents for Multiple Leaks in the Plant

Introduction: The inspectors identified an NCV having very low safety significance (Green) of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and

Drawings." Specifically, the licensee failed to initiate corrective action documents in accordance with plant procedures for multiple leaks found in the plant.

Description: During plant walkdowns, the inspectors identified numerous leaks. These leaks were in a variety of systems and equipment and were of various types: oil, boric acid, and water. Many of these leaks had not been entered into the licensee's corrective action program.

Because of the inspectors' findings, the licensee conducted a much more extensive walkdown of the plant to identify all the leakage in the plant. During this subsequent walkdown, the licensee identified 60 leaks in the plant that had never been entered into the corrective action program. While 30 of these leaks were not active at the time of discovery, the remaining leaks were active and involved both oil and water leakage in systems important to safety such as service water, component cooling, main steam, and main feedwater. As a result of this discovery, the licensee entered all of these deficiencies into its corrective action program. Additionally, the licensee initiated CR 026711 to identify and resolve the overall issue involving unidentified leaks in the plant.

Considering the large number of leaks in the plant, the inspectors determined that there was ample opportunity for the licensee to identify the majority of these leaks in the past. Additionally, the licensee's corrective action program, as outlined in station procedure PI-KW-200, Corrective Action, required that these leaks be identified by a Condition Report. Attachment 1 to this procedure contained a list of conditions that required the submittal of a Condition Report. Some of these conditions were degradation and damage of plant equipment and system, structure, and component (SSC) leaks. Based upon this, the leaks that were found during both the inspectors' walkdowns and the licensee's walkdowns would have required the initiation of a Condition Report.

Analysis: The failure to initiate a corrective action document for multiple occurrences of leaks in the plant was a performance deficiency warranting a significance determination. The inspectors concluded that the finding is greater than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 20, 2007, in that the finding is associated with the equipment performance attribute of the Mitigating System Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to identify and correct leakage on equipment important to safety could eventually lead to equipment unavailability during events that the equipment is designed to mitigate.

The finding screened as having very low safety significance (Green) using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for the At-Power Situations," dated January 10, 2008, because the inspectors answered "no" to all five questions under the Mitigating Systems Cornerstone column of the Phase 1 worksheet. Specifically, at the time that the leakage was discovered, none of the leaks immediately impacted the functionality of the equipment affected. The finding has a cross-cutting aspect in the area of human performance because the licensee failed to effectively communicate expectations regarding procedural compliance for the corrective action program (H.4.b).

Enforcement: 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, and drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to this, in November 2007, the licensee failed to follow its procedure, PI-KW-200, Corrective Action, for multiple occurrences of leaks in the plant. These conditions were not entered into the corrective action program as required by the procedure. Because the multiple unidentified leaks had similar causes, safety culture – a lack of proper safety focus among the plant staff, they were treated as one violation of 10 CFR 50, Appendix B, Criterion V.

Because this violation was of very low safety significance and because it was entered in the licensee’s corrective action program (as CR 026711), it is being treated as an NCV (NCV 05000305/2007011-02), consistent with Section VI.A of the NRC Enforcement Policy.

c. Failure to Update the Updated Safety Analysis Report (USAR) with Safety Analysis for Pressure Locking of Containment Sump Isolation Valves

Introduction: The inspectors identified a finding of very low safety significance for the licensee’s failure to adequately update the USAR in accordance with 10 CFR 50.71, “Maintenance of records, making of reports.” The licensee failed to update the USAR to fully reflect the results of a safety analysis performed in response to NRC Generic Letter 95-07, “Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves.”

Description: While reviewing station procedures, the inspectors discussed with site personnel the design of the containment sump suction piping. Specifically, the inspectors were reviewing the site’s response to Generic Letter 95-07 and the safety evaluation performed supporting that response. The evaluation stated that the residual heat removal (RHR) pump containment sump suction valves, SI-350A(B), were not susceptible to thermal-induced pressure locking because an air volume was maintained in the piping during normal plant operation. The NRC response (dated January 13, 1998) to the safety analysis found that maintaining the piping that contains valves SI-350A(B), and the associated downstream SI-351A(B) valves, in a dry condition eliminated the susceptibility of the valves to thermal-induced pressure locking and was thus acceptable. However, the station did not update the USAR to include the results of the safety analysis.

Analysis: The inspectors determined that the failure to update the USAR was a performance deficiency warranting further review. Because the issue potentially impacted the NRC’s ability to perform its regulatory function, this finding was evaluated using the traditional enforcement process. Typically, the severity level would be assigned after consideration of appropriate factors for the particular regulatory process violation in accordance with the NRC Enforcement Policy. However, the SDP is to be used, if applicable, in order to consider the associated risk significance of the finding prior to assigning a severity level. Using IMC 0612, Appendix B, “Issue Screening,” dated September 20, 2007, the inspectors determined the finding is greater than minor because of the potential to impact the regulatory process. Specifically, the failure to provide complete licensing and design basis information in the USAR could result in either the licensee making an inappropriate licensing interpretation or the NRC making an inappropriate regulatory decision based on incomplete information in the USAR. The finding screened as having very low safety significance (Green) after the inspectors performed a Phase 1 significance determination analysis in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for the At-Power Situations," dated January 10, 2008, and the inspectors answered "no" to all five questions under the Mitigating Systems Cornerstone column of the Phase 1 worksheet.

Enforcement: 10 CFR 50.71(e) stated that "each person licensed to operate a nuclear power reactor … shall update periodically … the final safety analysis report originally submitted as a part of the application for the operating license, to assure that the information included in the report contains the latest information developed. This submittal shall include the effects of all analysis of new safety issues performed by or on behalf of the licensee at Commission request." By letter dated July 1996, the licensee stated that as part of the analysis performed in response to Generic Letter 95-07, the RHR pump containment sump suction valves, SI-350A(B), were not susceptible to thermal-induced pressure locking because an air volume was maintained in the piping during normal plant operation.

Contrary to this, as of December 19, 2007, the licensee had not updated the USAR to reflect the safety analysis performed in response to Generic Letter 95-07. Specifically, the licensee did not identify that the RHR pump containment sump suction valves, SI-350A(B), were not susceptible to thermal-induced pressure locking because the piping was maintained in a dry condition during normal plant operation. Once identified, the licensee entered the issue into its corrective action program as CR 027353, "Failure to Update USAR with Pressure Locking Gate Valve Analysis." The violation was determined to be of very low safety significance; therefore, this violation of 10 CFR 50.71(e) was classified by NRC management as a Severity Level IV violation. Because the finding was of very low safety significance and was entered into the licensee's corrective action program, it is being treated as an NCV (NCV 05000305/2007011-03), consistent with Section VI.A.1 of the NRC Enforcement Policy.

d. Effects of Air Entrainment in ECCS Pumps

Scope: As part of the independent extent of condition review, the inspectors reviewed station emergency operating procedure ES-1.3, "Transfer to Containment Sump Recirculation," and background document BKG ES-1.3, "Transfer to Containment Sump Recirculation." The inspectors reviewed these procedures to assess procedure quality and to identify any operator workarounds.

Discussion: One issue was identified by the inspectors. BKG ES-1.3 discussed the air void between the containment sump suction supply valves. The inspectors asked engineering personnel if the air volume in the piping between valves SI-350A(B) and SI-351A(B) could potentially lead to air binding of the downstream ECCS pumps. Engineering personnel provided the inspectors with CAP 024206, "WNSAL 2004-007 – Containment Sump Line Fluid Inventory." This CAP was generated on November 24, 2004, in response to Westinghouse Nuclear Safety Advisory Letter (WNSAL) 2004-007, "Containment Sump Line Fluid Inventory," that discussed a potential vulnerability for trapped air in ECCS suction line piping. The evaluation performed for this CAP identified that Kewaunee was potentially susceptible to trapped air in the ECCS piping. This conclusion resulted in the generation of CAP 024797, "Potential for Air Void in

Containment Sump Recirculation Suction Line," dated January 1, 2005. Engineering personnel also provided the inspectors with an evaluation performed by a contractor that evaluated the effects of an air void in the ECCS sump suction piping. This evaluation concluded that the peak air entrainment rate would be 3 percent to 5 percent by volume over a period of 20 seconds, and that such entrainment rates would not be expected to cause any significant problems.

NUREG/CR 2792, "An Assessment of Residual Heat Removal and Containment Spray Pump Performance Under Air and Debris Ingestion Conditions," stated that for air quantities between 3 percent and 15 percent pump degradation depends on individual pump design and operating conditions. The inspectors asked the engineering staff if Kewaunee had an evaluation from the pump vendor that stated that 3 percent to 5 percent air entrainment would not adversely affect the ECCS pumps. On December 18, 2007, the licensee provided the inspectors with vendor information regarding the performance of the ECCS pumps. Until the inspectors complete a review of the contractor's analysis and the information from the pump vendor, this issue will be tracked as an unresolved item (URI 05000305/2007011-04). The analysis and the information indicated that the pumps were operable.

5. INDEPENDENT ASSESSMENT OF EXTENT OF CONDITION AND EXTENT OF CAUSE

White Performance Indicator: Unplanned Scrams per 7000 Critical Hours

.1 Inspection Scope

The inspection scope for this issue was similar to that described in Section 4 of this inspection report. The inspectors reviewed these event-based issues; and conducted an independent assessment for these issues that led to the White PI:

- RCE-38 - Automatic Reactor Trip Due to Loss of the Red Instrument Bus (October 30, 2006);
- RCE-718 - MFP [Main Feedwater Pump] MOC Switch Failure and Reactor Trip (April 26, 2006);
- RCE-754 - Reactor Trip During Turbine Testing (January 12, 2007);
- RCE-757 - Reactor Trip During Performance of SP-48-0041 (February 27, 2007); and
- RCE-745 – Low Range High Flux Reactor Trip (November 10, 2007).

In addition to the normal corrective action documents and logs, the inspectors reviewed the following documents:

- RCE-41 – Common Cause;
- RCE-39 – Substantive Crosscutting Issue in the Area of Human Performance; and
- RCE-40 – NRC Identified Crosscutting Issues Remain Open in the Area of PI&R.

.2 Assessments and Observations

a. Extent of Condition

(1) RCE-754 (Reactor Trip During Turbine Testing)

Observations: No extent of condition or extent of cause was done. The licensee determined either the operator moved the trip lever or the linkage was not properly adjusted. The causal evidence, independently reviewed, supported that cause. The licensee looked at other linkages and determined that the turbine-driven auxiliary feedwater pump had linkages, but these were significantly different from that involved with the main turbine. This was a reasonable assessment for linkage, but no other extent of condition was done to look at the operators' performance. Holding a lever with about ¾" of allowed movement before a trip occurs for over ten minutes was a difficult person-machine interface. The licensee did not look at other evolutions in which operators were in a position to possibly trip the plant, cause a safety system actuation, or cause a loss of safety function. These potential burdens should have been part of the extent of condition/cause. Licensee wrote CR 25616 to address this issue.

Assessment: The inspectors assessed this area by reviewing procedures (emergency operating procedures and abnormal operating procedures) and talking with several licensed and non-licensed operators to determine if there were operations' burdens which could cause a plant trip/transient/loss of function based on difficult operator tasks (such as, holding switches a long time, operating several components in a rapid series of steps to perform the function required). No items of significance were found.

(2) RCE-38 (Automatic Reactor Trip Due to Loss of the Red Instrument Bus)

Observations: The implementation of compensatory actions for thermography was not timely based on the trip risk and lack of any actions to prevent recurrence in place. The root cause was a failure of a silicon-controlled rectifier (SCR). No subcomponent failure analysis was done by the licensee. Therefore, what caused the SCR failure could not be validated by the inspectors. The licensee's extent of condition was adequate and determined all the inverters were susceptible. The licensee determined the red instrument bus was lost due to a SCR failure most probably caused by the more frequent cycling (quarterly) of a static switch. The more frequent cycling occurred because of needed PM for frequency drift and temperature deviations of uninterruptible power supply (UPS) boards. Since this had not been seen in the industry (no internal SCR failures have been seen, according to the licensee), the inspectors could not draw the same conclusion, other than it was unknown. Due to needed outage time, the Corrective Action to Prevent Recurrence (CAPR) to replace with a less susceptible design (UPS board redesign will not require the frequent adjustment) will not be done until 2008. The licensee had partially implemented a qualitative thermography assessment (compensatory action), recommended by the industry, as a check to ensure the inverter was acceptable prior to the switch movement. However, the licensee had not implemented the pre-PM thermography check (a corrective action in the root cause) which was to be done before cycling the static switch. This check took thermography data and compared it to the baseline data taken in the fall of 2007. This check was not scheduled to be done until the cycling in March 2008. Since the switch cycling was scheduled to take place in December 2007, the inspectors questioned the licensee why this was not in place because the other inverters were susceptible. The licensee documented the issue in CR 025851. The licensee determined thermography would be accomplished prior to switching the inverter to the alternate source and changed the site's schedule to conduct these.

Assessment: The inspectors watched the thermography done prior to the switch operation. The inspectors walked down the inverters, reviewed the inverter procedures, and watched the quarterly PM. The inspectors concluded that the thermography techniques and the procedures were reasonable and would be helpful in detecting possible faults in the SCR circuitry. No deficiencies were found during the thermography so this issue is considered minor.

(3) RCE-718 (MFP MOC Switch Failure and Reactor Trip)

Observations: The inspectors determined the extent of condition was thorough. The licensee determined there were operations' performance issues and material issues with the MOC in the breaker cubicle not being properly maintained (inadequate PM procedure). The causal evidence, independently reviewed, supported that cause. The condition impacted all safety-related and nonsafety-related 4-kilovolt breakers and the licensee looked at over 50 percent of them with no issues with any safety-related breakers. The sampling method for the 50 percent was based on risk significance and those breakers likely to have had activities which impacted the MOC. The 480-volt breakers had a lever arm for the MOC switches, but it was not adjustable; therefore, they were not sampled.

Assessment: The inspectors reviewed the causal evidence, including work orders and work requests, and determined no other breakers were impacted. The inspectors interviewed the cognizant engineers to validate the extent of condition assessment and found no issues of significance.

(4) RCE-757 (Reactor Trip During Performance of SP-48-0041) and RCE-745 (Low Range High Flux Reactor Trip)

Observations: The material root cause listed was 1) sulfidation of contacts due to poor design, 2) manufacturing defects, or 3) installation deficiencies. The causal evidence, independently reviewed, supported that cause. However, the CAPRs did not address receipt inspection (for manufacturing defects) or adequate procedures (for installation deficiencies). The focus was on addressing sulfidation, although causal evidence from an outside vendor and the site's own OE indicated that the other two causes were possible failure modes. However, the actions, tracked only as CAs, were sufficient to prevent a similar issue from occurring if the causes were due to defective material or poor installation. The licensee procedures for bench testing inspection, GIP-016A, and the procedure for installation, GIP-016B, were considered CAPRs by the inspectors.

The extent of condition for the material failure was narrow in scope. The relay that failed was a BF-66 style. Eighty-eight of the 148 BF 66 style relays of had been replaced and all relays that could cause blind failures at greater than 10 percent reactor power have been replaced. And others were scheduled for the 2008 refueling outage. The BF-66 relays for nuclear instrument overpower trips when reactor power was less than 10 percent were not replaced even though one relay failed in November 2006 when power was less than 10 percent and the reactor tripped (RCE-745). The licensee's strategy was that the replacement actions were balanced against wholesale change-out to minimize possible new issues arising (an infant mortality assessment for wholesale change out). Also, BF-66 relays in ESF systems were not inspected or replaced. Although sulfidation would not be an issue for most ESF relays (since most of these relays energize to actuate and thus would not pick up the sulfidation), the possible issues of manufacturing defects or installation inadequacies would need to be addressed. A failure of these relays could cause a loss of a safety component versus trip the plant. Since a visual inspection did not involve change-out and would provide a key source of information to the ESF system health, the inspectors concluded this was a performance deficiency (evaluated in Section 5.3.a. of the inspection report).

Assessment: The trip in February 2007 had the same cause as the trip in November 2006. The extent of condition for the trip in 2006 was too narrow and actions were not effective. The licensee's root cause noted this was a recurrence, but the site's corrective action metrics did not indicate this, and a CR to document this issue was never written. The licensee wrote CR 025633 to document the issue. The inspectors reviewed the inspections of the RPS relays. The inspectors concluded that the scope of replacement for the RPS relays and the method of inspection for those only inspected (and not replaced) were adequate to prevent a similar problem from occurring in the short-term. The inspectors also reviewed some of the RPS channel testing procedures. In addition, the inspectors watched part of the 'yellow' channel surveillance to determine if other possible procedure and human performance causal factors existed. None were noted. However, the inspectors concluded that the ESF relays could be impacted and were not adequately assessed by the licensee. The inadequate extent of condition from the 2007 trip for ESF relays is a finding in Section 5.3.a of this report.

b. Extent of Cause

(1) RCE-38 (Automatic Reactor Trip Due to Loss of the Red Instrument Bus)

Observations: The extent of cause actions will take several years to complete. The licensee determined that there were two extent of cause actions: one related to the PM optimization (too much cycling of the transfer switch led to the premature failure) and another for a proactive SPV program which would have prevented the plant trip on failure of the inverter. The just-in-time PM optimization program will be implemented soon and will be incorporated in the normal planning week. A detailed PM upgrade program was not part of the recovery plan at this time even though several events have causal factors for inadequate PMs. The second item, SPV - phase I - was finished on October 31, 2007, and the inverters were not included on the list. The second phase will be conducted starting in 2008. The licensee's effort to build the infrastructure in its recovery plan will address this type of issue based on a cost-benefit analysis. The inspectors looked at the current PM overdue list and found one item past its grace period. The licensee wrote CR 025649 to address the issue. The inspectors concluded that a minor vulnerability still existed in the area of inverter performance.

(2) RCE-718 (MFP MOC Switch Failure and Reactor Trip)

Observations: The extent of cause action was to establish an overall breaker program to ensure the correct actions were being done for breakers. The licensee was part of a Dominion fleet-wide effort in implementing a breaker program including using industry standards for breaker inspections. The licensee had dedicated resources, fleet support, and a schedule to complete before July 2008. The next phase will be to implement the plan into the schedule. The inspectors found this plan to be aggressive. The inspectors also reviewed the other facet of a breaker improvement plan: a training program. The inspectors concluded the current training material was thorough and, if properly implemented, should be effective.

(3) RCE-757 (Reactor Trip During Performance of SP-48-0041)

Observations: The actions to fully upgrade the material condition of the RPS system will take two to five years. The action to replace all relays either with sealed relays designed for the present application or with a solid state system will take several operating cycles. With a long lead time, the key attribute will be system monitoring and inspection of susceptible relays. The current processes were in place, but will require long-term vigilance and commitment.

.3 Findings

a. ESF System BF-66 Relay Failure Extent of Condition

Introduction: The inspectors identified an NCV of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” of very low safety significance (Green), for failure by the licensee to follow procedural requirements for performing an adequate extent of condition following relay failures that led to reactor trips in 2006 and 2007. Specifically, the licensee failed to perform an extent of condition action to inspect ESF relays when sufficient causal evidence was present that relays in the ESF system (BF-66 relays) were susceptible to sulfidation, installation deficiencies, or manufacturing defects.

Discussion: The inspectors independently assessed the issues concerning failure of safety-related relays. RCE-757 was a root cause for a reactor trip in February 2007 caused by a blind failure of a BF-66 relay. A blind relay failure is a failure where, with two parallel contacts, one contact fails and the failure is undetectable until another event occurs (for example, testing when the other contact opens and a function is actuated). A similar event occurred and resulted in a trip in November 2006. This failure and root cause, RCE-745, was also for blind relay failure for a BF-66 relay. The BF-66 relay was in RPS and some were located in the ESF system. In RPS, the relays were normally energized (that is, fail on loss of power to trip); in the ESF system, most were normally deenergized, but would actuate to perform the safety function. The site’s assessment indicated that the failures were related to sulfidation. Sulfidation, similar to oxidation, occurs when relay contacts stay in an energized state and begin to build up a sulfide film that may become thick enough to cause the loss of connectivity.

Although sulfidation has occurred at KPS, the historical record of reactor trips and defects from BF-66 relays indicated that causal factors other than sulfidation build-up could be occurring. As early as December 2006, before the February 2007 trip, the initial external lab report on the relay that failed in November indicated that contact misalignment (caused by material defects) was the cause of failure. In addition, installation practices in the past could have resulted in relay or contact failures. The inspectors determined the cause could not be definitively shown to be sulfidation, and that other failures should be considered. The licensee’s RCE also arrived at this conclusion.

During the shutdown in early 2007 to correct the BF-66 relays, the licensee changed out 88 of the 148 BF-66 style relays. The licensee's RCE also acknowledged the failure mechanism to be sulfidation, manufacturing defects, or installation deficiencies. All relays that could cause blind failures in RPS at reactor power greater than 10 percent were replaced. For the other RPS relays, the licensee conducted a detailed extent of condition by visual inspection of contacts and relays to ensure the possible causal factors could be detected. However, some ESF relays were BF-66 relays and had not been inspected. The inspectors questioned the licensee why there were no inspections of any type on record. The licensee's rationale was that the issue was only for normally closed contacts; however, some relays on ESF were normally energized and the other failure modes were possible and would be applicable to the ESF relays (installation deficiencies and manufacturing defects). The inspectors acknowledge that the sulfidation was unlikely on the normally deenergized relays; but since the safety system relays could be subject to the other casual factors and would not be detected until the actual actuation signal or every cycle testing, the inspectors concluded the licensee missed an opportunity to perform the extent of condition review for safety-related equipment. The licensee has an open action to conduct a visual review of some BF-66 relays in April 2008, but the inspectors concluded the licensee had the ability and the knowledge as early as December 2006 to take action to perform the extent of condition review for BF-66 relays in the ESF system.

Analysis: The inspectors determined that failure to comply with station procedure PI-AA-300 requirements to conduct an extent of condition review when casual analysis determines the conditions were likely to exist in other locations was a performance deficiency warranting evaluation. Using IMC 0612, Appendix B, "Issue Screening," dated September 20, 2007, the inspectors concluded that the issue is greater than minor because if left uncorrected, the failure to assess the other systems would become a more significant safety concern. The finding screened as having very low safety significance (Green) using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for the At-Power Situations," dated January 10, 2008, because no loss of safety function occurred.

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed and accomplished by procedures appropriate to the circumstances. Section 3.1.6 of station procedure PI-AA-300, a quality procedure, required that susceptible material or equipment be inspected when sufficient causal analysis allowed determination of where else the condition is likely to exist. Contrary to this, the licensee failed to conduct an adequate extent of condition review when failures occurred to BF-66 safety-related relays. Because this finding was of very low safety significance and was entered into the licensee's corrective action program as CR 026917, this violation is being treated as an (NCV 0500305/2007011-05), consistent with Section VI.A of the NRC Enforcement Policy.

6. SUMMARY AND CONCLUSION FOR COLLECTIVE REVIEW OF YELLOW INSPECTION FINDING AND WHITE PERFORMANCE INDICATOR

.1 Extent of Cause and Condition

Appropriately, most of the extent of cause evaluations focused on the organizational and programmatic issues that exist at Kewaunee. The key causes were the licensee's acceptance and tolerance of existing material conditions; weakness in correcting issues with the corrective action process; and generally weak management processes. The site had also operated in a 'silo,' not learning from the industry's overall body of knowledge. These facts indicated that the site's safety culture had weaknesses. RCE-41 for the site's common cause, SAR-000310 for the safety culture assessment, and the RCEs for the cross cutting issues (RCE-39 and RCE-40) determined that key processes, infrastructure, and safety cultural issues existed. Many of these items required upgrades in knowledge and standards to the corrective action program.

The inspectors reviewed RCE-41, looking specifically for how the site addressed weaknesses in its performance of extent of cause and extent of condition evaluations. The inspectors did not find any corrective actions in the RCE-41 to address the specific problems with both the effectiveness of extent of condition/extent of cause reviews. After discussion with plant management about this observation, the inspectors concluded that the site recognized that there was a weakness in the extent of cause and extent of condition reviews and that actions were planned to correct the weakness. The site wrote CR 025910 to address the issue and establish the needed links between RCE-41 and CR 25633 (which address the weakness in the site's extent of cause and extent of condition reviews) as well as linking RCE-41 to planned training to address the site's weakness in performing extent of cause and extent of condition reviews.

One central action for the site was to build a robust infrastructure. These key recovery team initiatives were directed by a senior vice-president and involved over 100 additional people. The projects included a corrective action excellence plan; building a critical equipment list; design basis document creation and critical calculation review; design and licensing basis integrated review; drawing program upgrade; engineering specification upgrade; bill of material program; high energy line break and heating, ventilation, and air conditioning calculation upgrade; site procedure upgrade; electrical calculation upgrade; building a Q-list; and conducting an SPV study. The inspectors sampled the procedure upgrade project and the calculation project for electrical procedures and identified no issues of significance.

The inspectors also monitored the daily and weekly routine of the site's organization in the area of corrective actions. The inspectors attended a corrective action review board meeting, including metric review and review of ACEs; attended pre-screening and screening of daily corrective actions; and attended plan of the day meetings. The meetings properly addressed the issues presented. In addition, the inspectors interviewed operators regarding safety conscious work environment and equipment reliability. All personnel stated they were comfortable raising a safety concern to their management. Most personnel indicated that equipment reliability was improving, although several major equipment issues remained.

.2 Summary and Conclusion

a. Summary

There were six events related to equipment failures: One Yellow inspection finding related to the 1A EDG fuel leak and One White PI for five events causing reactor trips.

Two RCEs had recurrences of similar event:

- A reactor trip based on relay failure, RCE-745 (November 2006); the extent of condition was inadequate and a reactor trip from a similar relay occurred, RCE-757 (February 2007).
- The EDG fuel oil leak from vibration induced tube/fitting failure, RCE 736 (August 2006); the actions were not adequate to prevent a similar failure on small diameter piping on the TSC DG.

Two RCEs had extents of condition/extents of cause which were too narrow in scope:

- RCE-736's extent of condition actions were done late and (in mid-2007) did not include a walkdown of systems other than diesels, even though other systems had vulnerable parts.
- RCE-754 (January 2007) evaluated a reactor trip during turbine valve testing, but had no extent of cause completed. It would have been reasonable to review other complex person-interface issues where operator performance could lead to a transient (similar to holding the turbine trip test lever for ten minutes).

One RCE had an extent of condition where the actions for review were not done when sufficient causal evidence was present:

- RCE-757 for the material failure was too narrow in scope. The relay failure was a BF-66 style. Eighty-eight of the 148 BF-66 style relays have been replaced. All relays that could cause blind failures in RPS at greater than 10 percent reactor power had been replaced, but ESF relays had no visual inspections for sulfidation, installation deficiencies, or manufacturing defects.

One RCE had an extent of condition for which an important compensatory action had not been completed timely when resources were available:

- RCE-38 required an action to do a thermography comparison to a baseline prior to cycling the static switch for the quarterly PM. The actual schedule for completion would have the thermography in March 2008 prior to the refueling outage.

The extent of cause did not provide actions to fully address the possible causes for 1A EDG fuel leak failure:

- RCE-736 did not evaluate the need to provide training on operability, which would have been appropriate since at least two licensed operators and a system engineer would not have considered operability an issue with a minor leak from a fitting, even if a CR were written.

- For RCE-736, the fitting failed from cyclic fatigue. No records could be found that indicated the fitting had been damaged or overstressed. But no analysis was completed to show that the old material would have had adequate endurance based on the installed condition, using normal maintenance practices. Knowing if the existing material would be rated acceptably could lead to another root cause (such as, the fitting was overstressed during some activity). This causal analysis may have provided an opportunity to evaluate maintenance or configuration control work practices. Finally, not having a detailed assessment that the new stainless steel would be acceptable could lead to a similar failure without a periodic PM program to ensure change-out of the fitting.

b. Conclusion

The inspectors concluded the licensee's extent of condition and extent of cause analysis had some weaknesses. The licensee's own external assessment performed in July and August 2007 indicated that the extent of cause and extent of condition assessments were weak. The licensee made extensive efforts to upgrade its cause evaluation methods, training, and actual evaluations. The licensee essentially re-performed all of the RCEs. Although this effort was important and was focused in the right direction, the inspectors found deficiencies with these new evaluations. While these deficiencies were of minor, or very low, safety significance, they still warranted licensee actions to address. Senior plant managers acknowledged that the corrective action program in general, and specifically the extent of condition/extent of cause reviews, needed continued, high level focus to address the weaknesses.

The licensee's plan was focused on the short-term, the long-term, and, finally, on a historical assessment of past root causes. The short-term actions directed a trained team (the CARE team - Corrective Action Review for Excellence team) to assess the quality of the cause evaluations. This team uses a detailed template with extent of condition/extent of cause guidelines and reports to a senior station manager who ensures the independence and quality of the team. The team was recently put in place and no assessment of its capability has been performed, as it was too early to make an assessment. The long-term action was to train the corrective action review board (the CARB, the approving authority of RCEs and select ACEs) and raise the level of knowledge of the root cause evaluators. This included formal training of all CARB members and continuing training of the site team. The CARB training was in progress and the new qualification will be reached for all CARB members by July 2008. Finally, the historical assessment was intended to review the quality of cause evaluations on risk significant systems to ensure there were no exiting conditions which would be unacceptable. This item is not scheduled to be completed until the end of 2008.

The site's material condition needed improvement and the licensee recognized this need. Because of the significant infrastructure that needed to be built, as well as the material condition upgrades, the inspectors concluded that there were challenges to resolving all of the short-term material issues at the site. The site's prioritization of material improvements, while re-evaluating old chronic material issues, was the key step in coordination with organizational improvements.

In summary, the licensee has made good progress in its training, analysis methodology, and evaluation of plant issues. The inspectors determined that the corrective actions outlined were adequate to address the deficiencies identified and that the licensee's management team was engaged in the site performance improvement process. However, many of the corrective actions associated with the Yellow inspection finding for the 1A EDG fuel oil leak, the White PI for unplanned scrams, and the collective RCEs performed for both issues have yet to be completed, and may not be completed until late 2008 or early 2009.

7. SAFETY CULTURAL CONSIDERATION

.1 White Performance Indicator: Unplanned Scrams per 7000 Critical Hours

The licensee performed a safety culture assessment for the reactor trips, referencing IMC 0305, “Operating Reactor Assessment Program,” and comparing the 13 elements of safety culture to the root and contributing causes. The licensee’s RCEs appropriately considered and recognized whether any safety culture component caused or significantly contributed to any risk significant performance issues. The inspectors did not identify any instances where the licensee failed to identify any safety culture component in its safety culture assessment. This area was considered satisfactory.

.2 Yellow Inspection Finding: Failure to Identify and Repair a Fuel Oil Leak on the 1A EDG

In RCE-736, the licensee identified that management expectations were not effectively implemented related to CAP initiation for equipment deficiencies. Additionally, the licensee, in RCE-736, recognized that there were safety culture aspects associated with the issue and subsequently initiated a Common Cause Action to conduct collective reviews of the past two safety culture assessments, a PI&R self-assessment, and the safety culture issues associated with the IP 95001 and IP 95002 root cause analyses. As discussed in Section 2.2.d. of this inspection report, the CCA resulted in Safety Culture Self-Assessment 000310.

This self-assessment identified several safety culture components that warranted improvement and consequently contributed to the issues. These components were Decision Making, Resources, Corrective Action Program, Continuous Learning, and Accountability.

The inspectors, as well, independently concluded that the primary cause for the 1A EDG fuel oil finding was related to safety culture issues. Additionally, the inspectors determined that the most applicable safety culture components were in the areas of Accountability, Decision Making, and Corrective Action Program.

Consequently, the inspectors determined that RCE-736 appropriately considered whether any safety culture component caused or significantly contributed to any risk significant performance issue.

8. OTHER ACTIVITIES

Review of the Mitigating Systems Performance Index for Emergency AC Power Systems

In the NRC’s assessment letter dated August 31, 2007, the licensee was informed that Kewaunee would receive an IP 95002 inspection for the Yellow inspection finding for the 1A EDG fuel oil leak, the White PI for unplanned scrams, and the White Mitigating

Systems Performance Index (MSPI) for Emergency AC Power Systems. Subsequent to that letter, the NRC approved FAQ (frequently asked question) 69.2, which removed 1193.9 hours of unplanned unavailability from June, July, and August of 2006. Also, the licensee re-evaluated other data and determined that a problem with the 1A EDG in March 2007 did not constitute an MSPI failure. The result of the removal of the unplanned unavailability hours and the MSPI failure resulted in the Kewaunee MSPI for Emergency AC Power Systems turning from White to Green.

As part of their extent of condition review for the Yellow inspection finding, the inspectors reviewed the licensee's evaluation of the MSPI issue. The inspectors reviewed RCE-761, "Potential Failure to Maintain EDG Post Accident Load Within Current Licensing Basis Requirement." The inspectors also reviewed the calculations performed to support FAQ 69.2.

The inspectors did not identify any deficiencies associated with the calculations performed to support FAQ 69.2. The inspectors also noted that although the EDG failures that led to the performance of RCE-61 were later determined to not be actual failures, the licensee still implemented the corrective actions of RCE-761. No deficiencies were identified by the inspectors.

9. EXIT MEETING

.1 Exit Meeting Summary

The inspectors presented the inspection results to Messrs. W. Matthews and S. Scace and other members of licensee management on December 19, 2007. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. The licensee did identify several documents provided to the NRC inspectors that contained proprietary information. None of this proprietary information was included in this inspection report.

.2 Regulatory Performance Meeting

On December 19, 2007, as part of the exit meeting for the IP 95002 inspection, the NRC met with the licensee to discuss its performance, in accordance with Section 06.05.a.1 of IMC 0305. During this meeting, Mr. J. Caldwell of the NRC and the licensee discussed the issues related to the Yellow inspection finding and the White PI that resulted in Kewaunee being placed in the Degraded Cornerstone Column of the NRC's Action Matrix. This discussion included the causes, corrective actions, extent of condition, extent of cause, and other planned licensee actions.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Scace, Site Vice-President
L. Armstrong, Site Engineering Director
P. Blasioli, Director, Nuclear Organizational Effectiveness
T. Breene, Nuclear Licensing Manager
M. Crist, Plant Manager
L. Hartz, Vice-President Nuclear Support Services
W. Henry, Maintenance Manager
B. Lembeck, Radiation Protection Supervisor
J. Ruttar, Operations Manager
D. Shannon, Health Physics Operations Supervisor
R. Steinhardt, Site Maintenance Rule Coordinator
C. Tiernan, Corporate Maintenance Rule Coordinator
S. Wood, Emergency Preparedness Manager

Nuclear Regulatory Commission

J. Caldwell, Regional Administrator
G. Shear, Deputy Director, Division of Reactor Projects
M. Kunowski, Chief, Division of Reactor Projects, Branch 5

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000305/2007011-04	URI	Effects of Air Entrainment in ECCS Pumps (Section 4.3.d)

Opened and Closed

05000305/2007011-01	NCV	Inadequate Extent of Condition Review for Fuel Leak (Section 4.3.a)
05000305/2007011-02	NCV	Failure to Initiate Corrective Action Documents for Multiple Leaks in the Plant (Section 4.3.b)
05000305/2007011-03	NCV	Failure to Update the Updated Safety Analysis Report (USAR) with Safety Analysis for Pressure Locking of Containment Sump Isolation Valves (Section 4.3.c)
05000305/2007011-05	NCV	Inadequate Extent of Condition Review of BF-66 Relays (Section 5.3.a)

Closed

05000305/2007007-01	VIO	Failure to Evaluate Operability of the 1A EDG When a Fuel Oil Leak Was Identified

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Calculations
- C-042-001; Safeguards Diesel Generator Loading; Revision 6, Addendum C

Corrective Action Program Documents
- CAP043795; RCE 757 Extent of Cause Work-Arounds; April 11, 2007
- CAP038991; Loss of Instrument Bus; November 12, 2006
- CAP031102; 1B RHR Pump Seal Leak; January 26, 2006
- CAP029888; Seal Leak on B RHR Pump; November 2, 2005
- CAP030328; RHR Pump Seal Leakage Information Inadequate; November 30, 2005
- CAP030374; System Integrity Program Issues; December 2, 2005
- CAP030399; SIP and USAR Documents Not Current; December 6, 2005
- CAP030487; IPEOPs May Not Adequately Address The Occurrence Sump Recirculation Leakage; December 12, 2005
- CAP030523; USAR Table 6.2-12 Does Not Accurately Represent Current Analysis Results; December 14, 2005
- CAP030536; NRC Question Related To Implementation of Approved Amendment 136 (SIP Program); December 14, 2005
- CAP030959; Boric Acid Leakage From A RHR Pump Seal And Pump Casing Bolting; January 18, 2006
- CAP042912; Updates to Calculation C10915; Revision 4
- CAP024797; Potential for Air Void in Containment Sump Recirculation Suction Line
- CAP024206; WNSAL 2004-007 – Containment Sump Line Fluid Inventory
- CAP029113; Nonconservatism in Calculation
- CAP033997; Sump A & B Volume Error in C10984
- CAP043215; Emergency AC NRC Performance Indicator May Turn White

Corrective Action
- CA010677; SPV Phase 1 – CEL Comparison for System 49 Control Rod Drive; October 26, 2007
- CA010677; SPV Phase 1 – CEL Comparison for Systems 54 Turbine/EH/Turbine Oil; October 26, 2007
- CA010677; SPV Phase 1 – CEL Comparison for System EG – Electrical Generation/Substation; October 26, 2007
- CA012411; CA to Eng Prog Insp & Mat to Review & Document Total Leakage; July 6, 2007
- CACC000138; Complete Training for CARB Members; December 13, 2007
- CACC000105; Development and Implement: Common Standards Report Templates Due January 18, 2008; Revision 0
- CA010508; CA to Perform Real-Time Review of Corrective Action Closure Quality (ongoing); June 7, 2007
- CA010677; Engineering Recovery Single Point Vulnerability List (phase I); June 11, 2007
- CA029366; Diesel Generator Coolant Leak RCE-736-CA-7 Extent of Condition Walk Down of EDG and TSC Diesel; January 26, 2007

- CA028514; Overhaul Low Medium Voltage Circuit Breaker, Establish Circuit Breaker Program; June 2007
- CA016032; Licensing to Determine and Document What Commitment There Is to Check and the Frequency
- CA017527; CA to Operations to Develop Procedural Guidance to Drain Piping if Level Reaches 75 percent
- CA017528; CA to Engineering Primary Systems Determine Analysis
- CA031673; Verify Past Loading in EDGs Did Not Result in a SSFF
- CA016616; CA to Eng Elec Sys (EDG System Engineer) to Track the Evaluation for 1A DG
- CA024341; Update the Status of C10122 to "Historical" in the Design Basis Database

Condition Evaluation
- CE017868; Sump A&B Volume Error in C10984
- CE019784; Diesel Generator Loads Cable Losses Not Included in DG Loading

Condition Report
- CR022266; RHR Pump A Seal Leakage; October 11, 2007
- CR025370; RHR Pump A Seal Leakage; November 21, 2007
- CR013476; Kewaunee Excellence Plan Item Within the Equipment Reliability Section; June 11, 2007
- CR016530; NRC Mock 95002 Inspection Team Problems With Effectiveness of CA's in RCEs; July 26, 2007
- CR016518; Extent of Condition Review Is Not Well Understood, by Plant Staff Mock 95002; July 24, 2007
- Administrative Procedure PI-KW-200; Corrective Action; Revision 3
- CR025591; 2007 95002 NRC Insp – ODM000026 Was Not Closed Out Adequately
- CR025616; 2007 95002 NRC Insp –NRC 95002 RCE 754 Extent of Cause
- CR025617; 2007 95002 NRC Insp – ODM028918: Perform ODM for 'A' PORV Leakage
- CR025633; 2007 95002 NRC Insp – Repeat Event Not Picked Up on CAP Effectiveness Indicator
- CR025635; 2007 95002 NRC Insp – IN 94-46 Needs To Be Re-evaluated for Leak Rate Calculation
- CR025637; 2007 95002 NRC Insp – Control Room Log Entry Accuracy
- CR025642; 2007 95002 NRC Insp – PMP 41-06 Not Completed Within Grace Time
- CR025649; 2007 95002 NRC Insp – EBL Conductance PM Past Grace Due Date
- CR025696; 2007 95002 NRC Insp – Debris Found on the Floor and on the 'B' Battery Rack
- CR025698; 2007 95002 NRC Insp – CR Was Not Submitted for Overdue PM as Required
- CR025716; 2007 95002 NRC Insp – Issue With RCE 736: EOC Performed
- CR025734; 2007 95002 NRC Insp – Evidence of Minor Oil Leak at Circulating Pump on EDG 1A and 1B
- CR025736; 2007 95002 NRC Insp – Leakage from SI Pump CCW Flow Indicator Swagelock Fitting
- CR025737; 2007 95002 NRC Insp – Guidance in ODM Document Not Followed
- CR025742; 2007 95002 NRC Insp – Enhancement to ODM Action Plan Identified
- CR025789; 2007 95002 NRC Insp – Air Hissing Sound From B Charging Pump
- CR025796; 2007 95002 NRC Insp – Question Regarding Use of Teflon Tape
- CR025822; 2007 95002 NRC Insp – Charging Pump B Oil Leak
- CR025824; 2007 95002 NRC Insp – Dry White Boric Acid Residue on ICS-20B
- CR025826; 2007 95002 NRC Insp – Dry White Boric Acid Residue on SI-7B Packing
- CR025835; 2007 95002 NRC Insp – A Small Amount of Dry White Boric Acid Residue at a Swagelok

- CR025850; 2007 95002 NRC Insp - Dry White Boric Acid Residue on the Swagelock Fitting for a Pressure Indicator
- CR025851; 2007 95002 NRC Insp – Scheduled Thermography Prior to Inverter Adjustments
- CR025902; 2007 95002 NRC Insp – Potential Finding for Thermography Issue CR025851
- CR025910; 2007 95002 NRC Insp – Extent of Cause/Condition
- CR026704; 2007 95002 NRC Insp – Ops Knowledge of Operability
- CR026711; Potential Adverse Trend Identification of Leaks
- CR026861; Non-Conformance Evaluation of Relay Lugs
- CR026886; 2007 95002 NRC Insp – SI-3 Actuator PM Out of Grace
- CR026897; 2007 95002 NRC Insp – Unclear Guidance for Required Reviews of Completed CAPRs
- CR026917; 2007 95002 NRC Insp – WSF Relay EOC Documentation
- CR027010; 2007 95002 NRC Insp – Minimum Temperatures
- CR027017; 2007 95002 NRC Insp – Procedural Clarification Needed for MA-KW-MPM-DGM-010B
- CR02702; 2007 95002 NRC Insp – Preconditioning for DG Test with SP-42-047S&B
- CR027025; 2007 95002 NRC Insp – Preconditioning of EDG During CO2 Testing
- CR027045; 2007 95002 NRC Insp – Gain Insights of DG Fuel Oil Tubing Endurance
- CR027049; 2007 95002 NRC Insp – Pipe Penetration 74 Off Center – No Evaluation
- CR027051; 2007 95002 NRC Insp – Procedural Compliance Issue Regarding Prerequisite of MPM-DGM-010
- CR027054; 2007 95002 NRC Insp – Procedural Placekeeping Issue Regarding OSP-DGE-002B
- CR027060; 2007 95002 NRC Insp – RHR Sump Recirculation Suction Not Per Licensing Basis
- CR016651; Safety Culture Assessment/Mock 95002 CR
- CR016530; NRC 95002 Mock Inspection Team Noted Problems
- CR020391; EDG Tiger Team Recommendation Schedule Development
- CR021179; EFR for RCE685 RC-1 CAPRs 2 Through 5 Failed and CR Screened as PRI 3
- CR0183530; Potential DBD Open Item Record for Sump ‘B’ Inspections for SI-350A, B
- CR027060; RHR Sump Recirculation Suction Not Per Licensing Basis
- CR020387; Level Increasing in Containment Sump Suction Piping
- CR019207; Document Past Operability Evaluation for 1A EDG
- CR028911; Submit FAQ on MSPI Unavailability

<u>Drawings</u>
- Drawing M-539; Flow Diagram – Reactor Misc. Vents, Drains and Sump Pump Piping; Revision P
- Drawing E-240; 4160 and 480 V Power Sources; Revision AN-1
- Drawing ES 1.3; Transfer to Cold Leg Recirculation
- Drawing E 0; Reactor Trip And Safety Injection
- WPS Drawing XK-100-1207; Reactor Trip and Permissive Relays; Revision 5k
- WPS Drawing XK-100-1206; Reactor Trip and Permissive Relays; Revision 4j
- WPS Drawing XK-100-1204; Reactor Trip and Permissive Relays; Revision 3l
- WPS Drawing E-2710; Engineered Safeguards System; Revision AA
- WPS Drawing E-2711; Engineered Safeguards System; Revision V
- WPS Drawing E-2712; Engineered Safeguards System; Revision N
- WPS Drawing E-2713; Engineered Safeguards System; Revision N

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- Abnormal Operating Procedure (AOP) OP-KW-AOP-CW-001; Abnormal Circulating Water System Operation; Revision 0
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- MA-KW-EDM-EDC-008B; Adjust Inverter Free Running Frequency; Revision 2
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- NID-01.02.03.06; Pressure Locking and Thermal Binding Effects of Motor-Operated Valves; Revision A
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Root Cause Evaluation
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- RCE-718 – MFP MOC Switch Failure and Reactor Trip
- RCE-754 – Reactor Trip During Turbine Testing
- RCE-757 – Reactor Trip During Performance of SP-48-0041
- RCE-761 – Potential Failure to Maintain EDG Post-Accident Load Within Current
- RCE-745 – Low Range High Flux Reactor Trip
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- Event Review Team Report November 10, 2006 RCE 745 Addendum
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- Event Review Team Report April 26 2006 RCE 718
- Event Review Team Report Jan 12 2007 RCE 754
- Event Review Team Report Oct 30 2006 RCE 38

LIST OF ACRONYMS USED

AC	Alternating Current
ACE	Apparent Cause Evaluation
AFI	Area For Improvement
CA	Corrective Action
CAP	Corrective Action Program Document
CAPR	Corrective Action to Prevent Recurrence
CARB	Corrective Action Review Board
CCA	Common Cause Action
CFR	Code of Federal Regulations
CR	Condition Report
DBD	Design Basis Document
DC	Direct Current
DG	Diesel Generator
dpm	Drop Per Minute
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
FYI	For Your Information
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
kV	Kilovolt
KPS	Kewaunee Power Station
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MFP	Main Feedwater Pump
MOC	Mechanically Operated Contact
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NOS	Nuclear Oversight (Quality Assurance)
NRC	U.S. Nuclear Regulatory Commission
OE	Operating Experience
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PM	Preventive Maintenance
RCE	Root Cause Evaluation
RHR	Residual Heat Removal
RPS	Reactor Protection System
SAR	Safety Culture Self-Assessment
SCR	Silicon-Controlled Rectifier
SPV	Single Point Vulnerability
SSC	System, Structure, and Component
TS	Technical Specification
TSC	Technical Support Center
UPS	Uninterruptible Power Supply
USAR	Updated Safety Analysis Report
URI	Unresolved Item
WO	Work Order