UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

October 28, 2005

Duke Energy Corporation (DEC)
ATTN.: Mr. R. A. Jones
Site Vice President
Oconee Nuclear Station
7800 Rochester Highway
Seneca, SC 29672

SUBJECT: OCONEE NUCLEAR STATION - INTEGRATED INSPECTION REPORT 05000269/2005004, 05000270/2005004, 05000287/2005004

Dear Mr. Jones:

On September 30, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Oconee Nuclear Station. The enclosed report documents the inspection findings which were discussed on October 4, 2005, with Mr. Bruce Hamilton and other members of your staff.

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

This report documents two self-revealing and four NRC-identified findings of very low safety significance (Green); five of which were determined to be violations of NRC requirements. However, because of their very low safety significance and because the issues were entered into your corrective action program, the NRC is treating these five findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any of the findings in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Oconee facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Michael E. Ernstes, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket Nos.: 50-269, 50-270, 50-287
License Nos.: DPR-38, DPR-47, DPR-55

Enclosure: NRC Integrated Inspection Report 05000269/2005004,05000270/2005004, 05000287/2005004 w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-269, 50-270, 50-287
License Nos:	DPR-38, DPR-47, DPR-55
Report No:	50-269/2005004, 50-270/2005004, 50-287/2005004
Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7800 Rochester Highway Seneca, SC 29672
Dates:	July 1, 2005 - September 30, 2005
Inspectors:	M. Shannon, Senior Resident Inspector A. Hutto, Resident Inspector E. Riggs, Resident Inspector R. Aiello, Senior Operations Engineer (Section 1R11) S. Rose, Senior Operations Engineer (Section 1R11) M. Chitty, Operations Engineer (Section 1R11)
Approved by:	Michael E. Ernstes, Chief Reactor Projects Branch 1 Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000269/2005004, IR 05000270/2005004, IR 05000287/2005004, 07/01/2005 - 09/30/2005; Oconee Nuclear Station, Units 1, 2, and 3; Maintenance Risk Assessments and Emergent Work Control, Surveillance Testing, Identification and Resolution of Problems, and Event Followup.

The report covered a three-month period of inspection by the onsite resident inspectors and three operations engineers. Six Green findings, five of which were non-cited violations (NCVs), were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using 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 3, dated July 2000.

A. NRC Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing finding was identified for inadequate maintenance and oversight of repair efforts on the actuator of 3DW-18 (the Unit 3 Upper Surge Tank (UST) Makeup Valve). Specifically, while attempting to repair an air leak on the actuator of 3DW-18, maintenance technicians removed the valve's bonnet and were ready to remove the valve's diaphragm with no hydraulic isolations made between the valve and the main condenser. Had the diaphragm been removed from 3DW-18, it is likely that Unit 3 would have tripped due to a loss of main condenser vacuum, as the top of the UST dome is vented to the main condenser.

  This event was considered to be a performance deficiency, as the licensee failed to provide adequate maintenance and oversight of the efforts to repair an air leak on the 3DW-18 actuator; thereby, increasing the likelihood of a unit trip with a loss of normal heat sink. This issue was considered to be more than minor because it affected the Initiating Events cornerstone objective of limiting the likelihood of events that upset plant stability. The finding is associated with the configuration control attribute, in that the inadequate maintenance and oversight of the repairs to the actuator of 3DW-18 increased the likelihood of a reactor trip with a loss of normal heat sink due to inadequate configuration control of a secondary plant system. The consequences of the finding were assessed through Phase 2 of the SDP, and although the likelihood of a unit trip was increased and would have resulted in a loss of the normal heat sink, the exposure time for this condition was less than 3 days and all other mitigation capabilities described on the Phase 2, SDP worksheet for transient (reactor trip) core damage sequences were maintained. Consequently, the finding was determined to be of very low safety significance. This finding involved the cross-cutting aspect of human performance. (Section 1R13)

- Green. A NRC-identified non-cited violation of 10 CFR 50 Appendix B, Criterion X, Inspection, was identified for the failure to develop and implement an inspection program for monitoring the main steam line in the Unit 1, 2 and 3 East Penetration Rooms. The finding was considered to be a performance deficiency in that the licensee had committed to perform inspections of the steam lines to support the acceptability of Duke's design and analysis for the main steam lines, but the inspections were not being performed.

The finding was considered to be more than minor because it impacted the Reactor Safety Initiating Events Cornerstone in that failure to perform the inspections could lead to failure to identify degrading main steam line conditions, which would cause an increase in the likelihood of an initiating event. The finding was screened as having very low safety significance under the Initiating Events Cornerstone, in that it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. This finding involved the cross-cutting aspect of Problem Identification and Resolution. (Section 1R22.3)

Cornerstone: Mitigating Systems

- Green. A NRC-identified non-cited violation of 10 CFR 50.74 was identified for failure to make a notification of a change in operator or senior operator status regarding information for one licensed operator concerning his medical qualification. Specifically, the operator failed to meet the American Nuclear Standards Institute /American Nuclear Society (ANSI/ANS-3.4, "Medical Certification and Monitoring of Personnel Requiring Operator Licenses for Nuclear Power Plants," 1983 Standard for a blood pressure (BP) limitation. This impacted the NRC's ability to perform its regulatory function, in that the NRC was not able to make a licensing decision with regards to a potential restriction to ensure compliance with ANSI/ANS-3.4. Consequently, an operator stood several watches in a Technical Specification license position with his BP greater than the ANSI/ANS limits.

  This finding is of very low safety significance because there was no evidence that the operator endangered plant operations as a result of hypertension while performing licensed duties since the original issuance of his license. However, the regulatory significance was important because pertinent information was not provided to the NRC when the operator knowingly discontinued taking his medication. Subsequently, this impacted a licensing decision for the individual. (Section 1R11.2)

- Green. A NRC-identified non-cited violation of 10 CFR 50 Appendix B, Criterion X, Inspection, was identified for the failure to develop and implement an inspection program for inspection and cleaning of the containment electrical penetrations located in the East and West Penetration Rooms of Units 1, 2, and 3.

  The finding was considered to be a performance deficiency in that the licensee had failed to develop an inspection program for their containment electrical penetrations to ensure cleanliness of the electrical connections. The inspectors concluded that if left uncorrected (no inspection) debris and rust accumulation could lead to failure of the electrical circuits during a high energy line break as a result of grounds and shorts. Therefore, failure to perform cleanliness inspections was considered to be more than minor because it could impact the Reactor Safety Mitigating Systems Cornerstone objective for reliability of a mitigating system/train (i.e., circuits needed to mitigate a high energy line break. The finding was screened as very low safety significance in the Phase 1 review under the Mitigating Systems Cornerstone, in that failure to perform an electrical penetration inspection was not considered to be a design deficiency, was not considered to represent a loss of safety system function, was not considered to represent an actual loss of safety function of a single train, and did not involve seismic, flooding or severe weather. This finding involved the cross-cutting aspect of Problem Identification and Resolution. (Section 1R22.2)

- <u>Green</u>. A NRC-identified non-cited violation of 10 CFR 50 Appendix B, Section XVI, Corrective Action, for inadequate corrective actions related to the lack of timeliness of repairs to a Unit 2 East Penetration Room floor seal.

  The failure to promptly repair the damaged floor seal was considered to be a performance deficiency. The finding was considered to be more than minor because if left uncorrected, additional seal area could fail and it would affect the Mitigating System Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events, in that the high pressure injection (HPI) pumps could be flooded following a high energy line break in the East Penetration Room. However, in the seal's current level of degradation, the inspectors concluded that the deficiency would not by itself result in the loss of function of the HPI pumps, because flooding would be limited by the size of the degraded/failed seal. Consequently, the finding was determined to be of very low safety significance, as it was screened out under the Mitigating Systems Cornerstone in the SDP Phase 1 Screening Worksheet with the determination that there was no loss of safety function. This finding involved the cross-cutting aspect of Problem Identification and Resolution. (Section 4OA2.6)

Cornerstone: Barrier Integrity

- <u>Green</u>. A self revealing, non-cited violation (NCV) of 10 CFR 50 Appendix B, Criterion X, Inspection, was identified for an inadequate quality control (QC) inspection associated with the installation of the thermal overloads on the Unit 1 and 2 Control Room Outside Air Booster Fan (CROABF) Train B.

  The finding was considered to be a performance deficiency because the licensee failed to conduct an adequate QC inspection of the installation of the S4.4 overload relay heater elements on the safety-related B CROABF. The licensee's failure to correctly install the thermal overloads on the Unit 1 and 2, B Train, CROABF was considered to be more than minor because it affected the Barrier Integrity Cornerstone attribute of maintaining control room habitability. Similar to NCV 05000269/2005002-02, this finding represented a similar degradation of the barrier function of the control room against smoke and/or a toxic atmosphere; thereby, requiring a Phase 3 evaluation be performed. However, since the exposure time associated with this CROABF finding is shorter than that used in the Phase 3 evaluation of NCV 05000269/2005002-02, it too is considered to be of very low safety significance. This finding involved the cross-cutting aspect of human performance. (Section 4OA3.3)

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status:

Unit 1 entered the report period at 100 percent rated thermal power (RTP). The unit was reduced to approximately 88 percent RTP on August 6, 2005, to perform turbine valve movement testing. The unit was returned to 100 percent RTP on the same day. The unit operated at or near 100 percent RTP for the remainder of the inspection period.

Unit 2 entered the report period at 100 percent RTP. The unit was reduced to approximately 88 percent RTP on July 9, 2005, to perform turbine valve movement testing. The unit was returned to 100 percent RTP on the same day. On September 26, 2005, the unit commenced a power coastdown in advance of the End-of-Cycle 21 (2EOC21) refueling outage, and the unit completed the inspection period at approximately 93 percent RTP. The unit operated at or near 100 percent RTP for the remainder of the inspection period.

Unit 3 entered the report period at 100 percent RTP. The unit automatically tripped on August 31, 2005, due to the complete loss of power to the newly installed digital control rod drive (CRD) system while performing CRD testing. A design deficiency resulted in an excessive cooldown of the reactor coolant system (RCS), resulting in an engineered safeguards actuation on low RCS pressure at 1600 psig. The unit entered a forced outage to identify the cause of the trip and overcooling event and to conduct repairs. Following repairs, the unit was taken critical on September 6, 2005, and returned to 100 percent RTP on September 8, 2005. The unit operated at or near 100 percent RTP for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

Tornado Watch (Remnants of Huricane Katrina)

a. Inspection Scope

The inspectors verified that the licensee responded appropriately to a tornado watch issued for Oconee County, SC on August 29, 2005. The inspectors verified that operations personnel entered abnormal procedure AP/0/A/1700/006, Natural Disaster, and that there were no ongoing maintenance activities on systems that required restoration by the procedure. The inspectors also verified that control room personnel had completed Enclosure 5.4, Severe Weather, as required by the AP.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

The inspectors conducted partial equipment alignment walkdowns to evaluate the operability of selected redundant trains or backup systems while the other train or system was inoperable or out of service. The walkdowns included, as appropriate, reviews of plant procedures and other documents to determine correct system lineups, and verification of critical components to identify any discrepancies which could affect operability of the redundant train or backup system. The following three systems were included in this review:

- The high pressure service water (HPSW) system with the B HPSW pump out of service (OOS) for the replacement of the pump's rotating element
- Keowee Hydro Unit (KHU) -1 and the underground power path with KHU-2 OOS following an emergency lockout while attempting to generate to the grid (Problem Investigation Process report (PIP) O-05-5118)
- Primary instrument air system with a backup instrument air compressor OOS for maintenance

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours in eighteen areas of the plant to verify that combustibles and ignition sources were properly controlled, and that fire detection and suppression capabilities were intact. The inspectors selected the areas based on a review of the licensee's safe shutdown analysis and the probabilistic risk assessment based sensitivity studies for fire-related core damage sequences. Inspections of the following areas were conducted during this inspection period:

- Unit 1, 2, and 3 Turbine Building Basement Level (3)
- Unit 1, 2, and 3 Equipment Rooms (3)
- Unit 1 and 2 East and West Penetration Rooms (4)
- Unit 1, 2, and 3 Auxiliary Shutdown Panels (2)
- Unit 1, 2, and 3 Turbine Building Ground Level (3)
- Unit 1, 2, and 3 Turbine Building Operating Level (3)

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Simulator Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on September 21, 2005. The scenario involved a main steam line break outside of containment. The simulated event was complicated by a failure of valves needed to isolate the faulted steam generator. The inspectors observed crew performance in order to assess licensed operator performance and the evaluators' critique, focusing on: communications; ability to take timely and proper actions; prioritizing, interpreting, and verifying alarms; correct use and implementation of procedures, including the abnormal procedures; timely control board operation and manipulation, including immediate operator actions; and oversight and direction provided by the shift supervisor and shift technical advisor. The inspectors did not observe any problems during the scenario.

b. Findings

No findings of significance were identified.

.2 Requalification Program

a. Inspection Scope

The inspectors reviewed the facility operating history and associated documents in preparation for this inspection. During the weeks of March 21 - 25 (in office) and March 28 - April 1 (on site), 2005, the inspectors reviewed documentation, interviewed licensee personnel, and observed the administration of simulator operating tests and Job performance Measures (JPMs) associated with the licensee's operator requalification program. Each of the activities performed by the inspectors was done to assess the effectiveness of the licensee in implementing requalification requirements identified in 10 CFR 55, "Operators' Licenses." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," and Inspection Procedure 71111.11, "Licensed Operator Requalification Program." The inspectors also reviewed and evaluated the licensee's simulation facility for adequacy for use in operator licensing examinations. The inspectors observed two operator crews during the performance of the operating tests. Documentation reviewed included written examinations, JPMs, simulator scenarios, licensee procedures, on-shift records, simulator modification request records and performance test records, the feedback process, licensed operator qualification records, remediation plans, watchstanding, and medical records. The records were inspected against the criteria listed in Inspection Procedure 71111.11. Documents reviewed during the inspection are listed in the Attachment to this report.

b. Findings

Introduction: A Green NRC-identified non-cited violation (NCV) of 10 CFR 50.74(c), Notification of change in operator or senior operator status, was identified for failure to notify the NRC of a change in a licensed operator's medical status.

Description: The NRC identified that, during the period between December 20, 2004 and January 24, 2005, an operator stood several watches in a TS license position with blood pressure (BP) greater than ANSI/ANS-3.4-1983, "Medical Certification and Monitoring of Personnel Requiring Operator Licenses for Nuclear Power Plants," limits. When the facility became aware of the operator's failure to meet these limits, they failed to notify the NRC.

A NRC licensed operator's medical record indicated that he had BP in excess of the ANSI/ANS-3.4-1983 limits. On February 12, 2004, the facility licensee sent a letter to the NRC identifying that this operator was on medication for controlling high BP. The NRC doctor stated that a medical condition was not necessary to be placed on his license since he was on medication and it was being controlled. In a medical examination on December 20, 2004, the facility determined that the operator took it upon himself to try to reduce his BP with diet but was unsuccessful. This medical examination also determined that the operator's non-medicated BP was outside of the ANSI/ANS-3.4-1983 limits. In the meantime, the operator conducted licensed activities with his BP greater than the ANSI/ANS-3.4-1983 limits during the period stated above.

Analysis: The facility licensee's failure to report that one of their licensed operators did not meet the requirements of ANSI/ANS-3.4-1983 as required by 10 CFR 50.74 was a performance deficiency. This was reasonably within the licensee's ability to foresee and prevent. Because this issue affected the NRC's ability to perform its regulatory function, it was evaluated using the traditional enforcement process. The regulatory significance was important because pertinent information was not provided to the NRC when the operator knowingly discontinued taking his medication. Subsequently, this impacted a licensing decision for the individual. This finding is of very low safety significance (Green) because there was no evidence that the operator endangered plant operations as a result of hypertension while performing licensed duties since the original issuance of his license.

Enforcement: 10 CFR 50.74 states, in part, that each licensee shall notify the NRC within 30 days of identifying a permanent disability or illness as described in 10 CFR 55.25 of this chapter. 10 CFR 55.25 states, in part, that "If, during the term of the license, the licensee develops a permanent physical or mental condition that causes the licensee to fail to meet the requirements of § 55.21 of this part, the facility licensee shall notify the Commission, within 30 days of learning of the diagnosis, in accordance with § 50.74(c). For conditions for which a conditional license (as described in § 55.33(b) of this part) is requested, the facility licensee shall provide medical certification on Form NRC 396 to the Commission (as described in § 55.23 of this part)."

The facility licensee must also certify which industry standard (i.e., the 1983 or 1996 version of ANSI/ANS-3.4, or other NRC-approved method) was used in making the fitness determination. 10CFR 55.57(b)(1) states, in part, "the medical condition and general health of the licensee continue to be such as not to cause operational errors that endanger public health and safety." It is incumbent upon the facility licensee to ensure that individual licensed operators are medically qualified to operate the plant or perform licensed duties. The facility's physician must determine whether the operator meets the requirements of section 55.57(b)(1), (i.e., the operator's medical condition and general health will not adversely affect the performance of assigned operator duties or cause operational errors that endanger public health and safety.) Furthermore, the facility must notify the NRC on NRC Form 396 regarding his medical status and potential medical issues that may require a license condition.

Contrary to the above, the licensee failed to notify the NRC after becoming aware of a potential disqualifying medical condition. The failure to report noncompliance with the ANSI/ANS-3.4-1983 medical requirements, as implied by 10 CFR 50.74, is of low safety significance. Additionally, this issue has been entered into the facility's corrective action program (PIP O-05-02152). Therefore, this violation is being treated as an NCV, consistent with section VI.A of the NRC Enforcement Policy: NCV 05000269,270,287/2005004-01, Performing Licensed Duties While Medically Unqualified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's effectiveness in performing routine maintenance activities. This review included an assessment of the licensee's practices pertaining to the identification, scoping, and handling of degraded equipment conditions, as well as common cause failure evaluations. For each item selected, the inspectors performed a detailed review of the problem history and surrounding circumstances, evaluated the extent of condition reviews as required, and reviewed the generic implications of the equipment and/or work practice problem. For those systems, structures, and components (SSCs) scoped in the maintenance rule per 10 CFR 50.65, the inspectors verified that reliability and unavailability were properly monitored and that 10 CFR 50.65 (a)(1) and (a)(2) classifications were justified in light of the reviewed degraded equipment condition. The inspectors reviewed the following items:

- KHU-2, which included the following PIPs: O-05-5118, KHU-2 Emergency Lockout While Attempting to Generate to the Grid; and O-05-5365, KHU-2 Emergency Lockout While Performing PT/0/A/0620/016, Keowee Hydro Emergency Start Test

- 1RIA-40 (Unit 1, Condenser Air Ejector Offgas Radiation Indicating Alarm), which included the following: PIP O-05-5009,1RIA-40 count rate indication has been increasing over time and varies significantly when compared to 2RIA-40 and 3RIA-40; and IP/0/B/0360/037, 1RIA-40, Sorrento Gas Monitor

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluations

a. Inspection Scope

The inspectors evaluated the following attributes for the eight selected SSCs and activities listed below: (1) the effectiveness of the risk assessments performed before maintenance activities were conducted; (2) the management of risk; (3) that, upon identification of an unforseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (4) that maintenance risk assessments and emergent work problems were adequately identified and resolved.

- Relay replacement on standby bus to main feeder bus supply breakers B1T-6 and B1T-7 with the A Lee Combustion Turbine OOS
- B HPSW pump with the 1X6 Motor Control Center OOS for relay replacement
- B HPSW pump with the Primary Instrument Air Compressor OOS
- PIP O-05-4724, Near Miss During Scheduled Work to 3DW-18
- PIP O-05-5376, Orange Risk Condition During Severe Thunderstorm Warning with KHU-2 and the Overhead Power Path OOS
- PIP O-05-5551, Tornado Watch (Remnants of Hurricane Katrina) Combine With Yellow Risk Significant Maintenance Items to Cause Orange Risk Condition
- PIP O-05-5938, Unable to Isolate and Drain Elevated Water Storage Tank Due to Orange Risk Condition Activity With no Documented Plant Operations Review Committee Review
- PIP O-05-5987, Unit 2 Reactor Protection System Channel B Placed in Manual Bypass Due to Inoperability of 2NI-6

b. Findings

Introduction: A Green self-revealing finding (FIN) was identified for inadequate maintenance and oversight of repair efforts on the actuator of 3DW-18 (the Unit 3 Upper Surge Tank (UST) Makeup Valve). Specifically, while attempting to repair an air leak on the actuator of 3DW-18, maintenance technicians removed the valve's bonnet and were ready to remove the valve's diaphragm with no hydraulic isolations made between the valve and the main condenser. Had the diaphragm been removed from 3DW-18, it is likely that Unit 3 would have tripped due to a loss of main condenser vacuum, as the top of the UST dome is vented to the main condenser.

Description: At approximately 3 p.m. on July 20, 2005, with Unit 3 in Mode 1 at 100 percent RTP, the bonnet of 3DW-18 was removed to repair an air leak on the valve's actuator. The maintenance crew was ready to pull the valve's diaphragm, when they noticed it was under a vacuum. The work crew stopped work and questioned the condition with the Work Control Center (WCC) Senior Reactor Operator (SRO). The removal of the diaphragm would have exposed the unit's main condenser to a 6-inch pathway to atmosphere. PIP O-05-4724 states, "The WCC SRO knew that there was no hydraulic isolation on the line and immediately stopped the crew and instructed them to return the valve to the condition they had found it in before they started work. Had the diaphragm been removed from the valve it would have most likely resulted in a unit trip on loss of vacuum. The WCC SRO was under the impression that the work order was only for repair of an air leak on the actuator and not for disassembly of the valve itself." As documented in PIP O-05-4724, a licensee investigation concluded that, "Operations (OPS) personnel failed to follow their approved tagout process. Consequently, they failed to comprehend that hydraulic isolation was required for 'DW-18 Repair Air Leak on Actuator' work. After determining that work external to the system only was being performed an inadequate tagout that led to this event was issued." The PIP also states that, "The details of the work scope required to ensure proper isolation would occur was unclear to OPS personnel. Consequently, OPS personnel did not recognize that a hydraulic isolation of DW-18 was necessary."

Analysis: This event was considered to be a performance deficiency, as the licensee failed to provide adequate maintenance and oversight of the efforts to repair an air leak on the 3DW-18 actuator; thereby, increasing the likelihood of a unit trip with a loss of normal heat sink. This issue was considered to be more than minor because it affected the Initiating Events cornerstone objective of limiting the likelihood of events that upset plant stability. The finding is associated with the configuration control attribute, in that the inadequate maintenance and oversight of the repairs to the actuator of 3DW-18 increased the likelihood of a reactor trip with a loss of normal heat sink due to inadequate configuration control of a secondary plant system. The consequences of the finding were assessed through Phase 2 of the SDP, and although the likelihood of a unit trip was increased and would have resulted in a loss of the normal heat sink, the exposure time for this condition was less than 3 days and all other mitigation capabilities described on the Phase 2, SDP worksheet for transient (reactor trip) core damage sequences were maintained. Consequently, the finding was determined to be of very low safety significance (Green). This finding involved the cross-cutting aspect of human performance.

Enforcement: This finding was not a violation of regulatory requirements because the Unit 3 main condenser is not considered to be safety-related, and therefore not under the requirements of 10 CFR 50, Appendix B. This finding is identified as FIN 05000287/2005004-02, Inadequate Maintenance and Oversight Increased the Likelihood of a Unit 3 Reactor Trip with a Loss of Normal Heat Sink. This issue has been entered into the licensee's corrective action program as PIP O-05-4724.

1R14 Personnel Performance During Non-routine Plant Evolutions

a. Inspection Scope

The inspectors reviewed the operating crew's performance during selected non-routine events and/or transient operations to determine if their response was appropriate to the event. As applicable, the inspectors: (1) reviewed operator logs, plant computer data, or strip charts to determine what occurred and how the operators responded; (2) determined if operator responses were in accordance with the responses required by procedures and training; (3) evaluated the occurrence and subsequent personnel response using the SDP; and (4) confirmed that personnel performance deficiencies were captured in the licensee's corrective action program. The non-routine evolutions reviewed during this inspection period included the following:

- PIP O-05-5118, KHU-2 Emergency Lockout While Attempting to Generate to the Grid
- PIP O-05-5365, KHU-2 Emergency Lockout While Performing PT/0/A/0620/016, Keowee Hydro Emergency Start Test
- PIP O-05-5613, Unit 3 Reactor Trip
- PIP O-05-5252, Abnormal Statalarms Following Standby Shutdown Facility (SSF) Diesel Generator (DG) Start
- PIP O-05-0122, Supply Breaker for Unit 3, SSF-Powered Pressurizer Heaters Found Out of Position

b. Findings

Introduction: An Unresolved Item (URI) was identified regarding inadequate design control associated with the failure to close the Unit 3, Bank 2, Group C pressurizer heater supply breaker prior to entering Mode 3 following the 3EOC21 refueling outage (RFO). This issue resulted in the SSF auxiliary service water (ASW) system being unable to perform its intended safety function and has been designated as an URI pending a Phase 3 risk analysis.

Description: On March 7, 2002, the licensee documented, in PIP O-02-1066, the lack of sufficient SSF-powered pressurizer heaters to maintain single phase, natural circulation RCS flow during an SSF-related event. On May 6, 2002, the licensee documented this issue in Licensee Event Report (LER) 50-269/2002-01, Pressurizer Heat Loss Exceeds Standby Shutdown Facility Powered Heater Capacity, and on December 30, 2003, the licensee received the low to moderate safety significant (White) violation 05000269, 270,287/2003012-01, Failure to Promptly Identify and Correct Insufficient SSF Pressurizer Heater Capacity. One of the corrective actions associated with PIP O-02-1066 was to increase the capacity of SSF-powered pressurizer heaters for each Oconee unit. On Unit 3, these modifications were performed during the 3EOC21 RFO in the Fall of 2004.

As documented in PIP O-05-0122, on January 4, 2005, with Unit 3 in Mode 1, the licensee discovered that supply breaker PXSF-4A for the Unit 3, Pressurizer Heater Bank 2, Group C was open. The unit was at approximately 20 percent RTP with power escalation in progress following the completion of the 3EOC21 RFO. A licensee investigation concluded that the cause of the breaker being mispositioned was the failure of operations personnel to follow management guidance for the removal and restoration process. A contributing cause to this incident was the lack of procedural guidance to ensure the breaker would be placed in the desired position, in that the startup procedure was not changed to reflect the installation and operation of this new equipment. The breaker had been mispositioned for approximately 234 hours prior to being closed by the licensee on January 4, 2005.

Analysis: The inspectors determined that the licensee's failure to maintain design control of PXSF-4A following its installation was a performance deficiency because the licensee failed to update procedural guidance associated with the breaker's operation. The failure to maintain adequate design control over the breaker PXSF-4A was considered to be more than minor because it affected the mitigating systems cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding is associated with the configuration control attribute, in that, the operational lineup for the Unit 3, Pressurizer Heater Bank 2, Group C supply breaker was not maintained. A Phase 1 SDP screening was performed, and it was determined that a Phase 2 analysis was required, as the finding represented an actual loss of the safety function of the SSF. This was based on the conclusion that during an SSF-related event, the insufficient SSF-powered pressurizer heaters would result in the inability to control RCS pressure via a pressurizer steam bubble. This would result in the inability to maintain single phase, natural circulation RCS flow without utilizing solid plant operations; thereby, rendering the SSF ASW system inoperable as indicated in the TS bases. The Phase 2 initiator and system dependancy table within the Oconee Risk Informed Notebook references a note to submit any findings associated with the SSF-powered, pressurizer heaters for a Phase 3 risk evaluation by a Regional Senior Reactor Analyst. This finding involved the cross-cutting aspect of human performance.

Enforcement: 10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that measures be established to assure that design basis for structures, systems, and components covered by Appendix B are correctly translated into specifications, drawings, procedures and instructions. Contrary to the above, the licensee failed to maintain adequate design control of the Unit 3, Bank 2 Group C pressurizer heater breaker, in that, the licensee failed to update the startup procedure with regard to the newly installed breaker. Pending determination of the risk significance, this finding will be identified as URI 05000287/2005004-03, Failure to Maintain Design Control of the SSF Supply Power Breaker for Unit 3, Bank 2, Group C Pressurizer Heaters.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected operability evaluations affecting risk significant systems, to assess, as appropriate: (1) the technical adequacy of the evaluations; (2) whether continued system operability was warranted; (3) whether other existing degraded conditions were considered; (4) if compensatory measures were involved, whether the compensatory measures were in place, would work as intended, and were appropriately controlled; and (5) where continued operability was considered unjustified, the impact on Technical Specification (TS) limiting condition for operations (LCOs). The inspectors reviewed the following seven operability evaluations:

- PIP O-05-4502, During the Performance of Low Pressure Injection (LPI) Valve Stroke Performance Test (PT), 3LP-7 Stroked Too Quickly

- PIP O-05-4503, SSF Reactor Coolant Makeup Unit Pump Suction Temperature Oscillating

- PIP O-05-4646, Water Discovered Inside of 230kV Switchyard DC Distribution Panelboards SY-DC1, DYA, DYB, DYC and DYD

- PIP O-05-4649, Single Failure Vulnerability of DC Panel with KHU-2 Aligned to Overhead Power Path

- PIP O-05-4720, SSF DG Engine Exhaust Fan Suction Found Partially Blocked

- PIP O-05-5086, Actual Size of Maximum [Reactor Building Emergency Sump] Screen Opening is Larger Than Stated in the LPI Design Basis Document

- PIP O-05-5118, KHU-2 Emergency Lockout While Attempting to Generate to the Grid

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

Risk Significant Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed the significant operator work-around listed below to determine if the functional capability of the respective system or the human reliability in responding to an initiating event were affected. The inspectors specifically evaluated the effect of the operator work-arounds on the ability to implement abnormal or emergency operating procedures. The inspectors also assessed what impact it would have on the unit if the work-around could not be properly performed.

- PIP O-05-5935, 1CS-5 Failed to Close After Pumping the Quench Tank to 1A Bleed Hold Up Tank. 1CS-5 was declared inoperable, requiring 1CS-6 to be deactivated to isolate the containment penetration. In order to decrease the frequency at which the quench tank is pumped, the maximum operating level of the quench tank was increased. Additionally, OPS personnel must clear tags on 1CS-6 to unisolate the containment penetration in order to pump the quench tank.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT)

a. Inspection Scope

The inspectors reviewed PMT procedures and/or test activities, as appropriate, for selected risk significant systems to assess whether: (1) the effect of testing on the plant had been adequately addressed by control room and/or engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documents; (4) test instrumentation had current calibrations, range, and accuracy consistent with the application; (5) tests were performed as written with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; and (8) equipment was returned to the status required to perform its safety function. The inspectors observed testing and/or reviewed the results of the following six tests:

- PT/2/A/0204/007, 2B Reactor Building Spray (RBS) Pump Test, following testing and inspection of the pump’s motor
- PT/1/A/0251/001, Unit 1and 2 A Low Pressure Service Water Pump Test, following pump lubrication
- PT/2/A/0600/13A, 2A Motor Driven Emergency Feedwater (MDEFW) Pump Test, following pump lubrication
- PT/0/A/0400/005, SSF ASW Pump Test, following the replacement of the outboard stuffing box packing
- PT/0/A/0620/016, Keowee Hydro Emergency Start Test, following repairs associated with the second emergency lockout on KHU-2
- OP/0/A/1600/010, Operation of the SSF DG, following routine preventive maintenance

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

.1 Routine Surveillance

a. Inspection Scope

The inspectors witnessed surveillance tests and/or reviewed test data of the five risk-significant SSCs listed below, to assess, as appropriate, whether the SSCs met TS, Updated Final Safety Analysis Report (UFSAR), and licensee procedure requirements. In addition, the inspectors determined if the testing effectively demonstrated that the SSCs were ready and capable of performing their intended safety functions.

- *PT/3/A/0600/013, 3B MDEFW Pump Test
- *PT/2/A/0202/011, 2C High Pressure Injection (HPI) Pump Test
- HP/0/B/1000/060 D, Procedure for Vent, Air Ejector and Reactor Building Sampling and Analysis
- AM/0/A/1300/059, Pump - Submersible - Emergency SSF Water Supply - Installation and Removal
- *PT/3/A/0600/012, Unit 3 Turbine Driven Emergency Feedwater Pump Test

Note: (*) Indicates in-service test (IST).

b. Findings

No findings of significance were identified.

.2 Inadequate Inspection of Containment Electrical Penetrations

a. Inspection Scope

As part of the surveillance inspection procedure, the inspectors reviewed the activities associated with inspection and cleaning of the containment electrical penetrations following identification by the inspectors that a significant number of electrical penetration covers had been removed during previous maintenance activities.

b. Findings

Introduction: The inspectors identified a Green non-cited violation (NCV) of 10 CFR 50 Appendix B, Criterion X, Inspection, for failure to develop and implement an inspection program for inspection and cleaning of the containment electrical penetrations located in the East and West Penetration Rooms. Discussions with the licensee disclosed that no procedures were in place to perform inspections or cleaning.

Description: Information Notice (IN) 82-03, Environmental Tests of Electrical Terminal Blocks, indicated that cleanliness of terminations and terminal blocks in circuits important to safety is of concern. It stated, in part, that the cleanliness aspects are addressed in Appendix B of 10 CFR 50 and that these regulations require the licensee to establish appropriate procedures to assure that equipment is maintained in an acceptable state. It also indicated that licensees are reminded that their plant preventive maintenance program should assure that periodic inspection of those terminations and terminal blocks for cleanliness and installation integrity is performed following any maintenance activity affecting them.

Based on discussions with NRR, it was concluded that IN 82-03 and 10 CFR 50 Appendix B, Criterion X, required the licensee to develop and implement a program for inspection of the containment electrical penetrations. Discussions during August 2005 disclosed that the licensee did not have a program for routine inspection and cleaning of the containment electrical penetrations. The inspectors noted that many of the protective covers had been removed and some of the terminal blocks had indications of dirt and rust accumulation. Therefore, the failure to develop an inspection program for the containment electrical penetrations was considered to be a violation.

Analysis: The finding was considered to be a performance deficiency in that the licensee had failed to develop an inspection program for their containment electrical penetrations to ensure cleanliness of the electrical connections. The inspectors concluded that if left uncorrected (no inspection), debris and rust accumulation could lead to failure of the electrical circuits during a high energy line break as a result of grounds and shorts. Therefore, failure to perform cleanliness inspections was considered to be more than minor because it could impact the Reactor Safety Mitigating Systems Cornerstone objective for reliability of a mitigating system/train (i.e., circuits needed to mitigate a high energy line break (HELB)). The finding was screened as very low safety significance (Green) in the Phase 1 review under the Mitigating Systems Cornerstone, in that failure to perform an electrical penetration inspection was not considered to be a design deficiency, was not considered to represent a loss of safety system function, was not considered to represent an actual loss of safety function of a single train, and did not involve seismic, flooding or severe weather. This finding involved the cross-cutting aspect of Problem Identification and Resolution.

Enforcement: 10 CFR 50 Appendix B, Criterion X, Inspection, requires that a program for inspection of activities affecting quality shall be established and executed to verify conformance with the instructions and procedures. Contrary to the above, the licensee failed to establish an inspection program for inspection of the containment electrical penetrations to ensure proper cleanliness of the penetrations. Because this issue was of very low safety significance and has been entered into the licensee's corrective action program (PIP O-05-4491), this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000269,270,287/2005004-04: Failure to Develop and Implement a Cleanliness Inspection Program for the Containment Electrical Penetrations.

.3 Inadequate Inspection of Main Steam Lines

a. Inspection Scope

As part of the surveillance inspection procedure, the inspectors reviewed the inspection activities associated with licensee commitments to the 1972 Giambusso Letter (HELB).

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR 50 Appendix B, Criterion X, Inspection, for failure to develop and implement an inspection program for monitoring the main steam line in the East Penetration Rooms. Discussions with the licensee disclosed that the main steam line postulated break areas were not being inspected.

Description: The Oconee licensing basis for high energy line breaks is contained in the December 15, 1972, letter from A. Giambusso to Duke Power Company (Giambusso letter) and the licensee's response to the letter which is documented in Oconee MDS

Report No. OS-73.2, Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment. In response to Question 7 of the Giambusso letter, which is related to a main steam line break in the East Penetration Room, OS-73.2 Supplement 1, dated June 22, 1973, stated that "Duke will increase the inservice inspection to include the metal to surface inspection of the postulated break area every 5 years to detect any surface defects." The licensee also provided drawings (OS-73.2 Supplement 1, Figure 2.1-1.b) showing the postulated break area in the East Penetration Room.

In August 2005 the inspectors asked for the latest inspection results for the main steam lines. The inspectors were informed that the main steam line terminal end break area was inaccessible and could not be inspected. The licensee had not informed the NRC that the terminal end break area provided on Figure 2.1-1.b was in error and that inspection of the main steam line piping in the East Penetration Rooms was not being performed. This issue was captured in PIP O-05-06354, which reflected the licensee's intention to ask NRR for an exemption from the inspection requirements.

Analysis: The finding was considered to be a performance deficiency in that the licensee had committed to perform inspections of the steam lines to support the acceptability of Duke's design and analysis for the main steam lines, but the inspections were not being performed. The finding was considered to be more than minor because it impacted the Reactor Safety Initiating Events Cornerstone in that failure to perform the inspections could lead to failure to identify degrading main steam line conditions, which would cause an increase in the likelihood of an initiating event. The finding was screened as being of very low safety significance (Green) under the Initiating Events Cornerstone, in that the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. This finding involved the cross-cutting aspect of Problem Identification and Resolution (PI&R).

Enforcement: 10 CFR 50 Appendix B, Criterion X, Inspection, requires that a program for inspection of activities affecting quality shall be established and executed to verify conformance with the instructions and procedures. Contrary to the above, the licensee failed to establish and execute the inspection program for inspection of the main steam lines committed to as part of their response to the 1972 Giambusso letter. Because the failure to perform the inspections was considered to be of very low safety significance and has been entered into the licensee's corrective action program (PIP O-05-06354), this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000269,270,287/2005004-05: Failure to Implement an Inspection Program for the Main Steam Lines.

1R23 Temporary Modifications

a. Inspection Scope

While performing plant status inspection activities, the inspectors reviewed the activities associated with the improper enclosure of the Unit 3 Train B low pressure injection (LPI)/reactor building spray (RBS) pump room (Room 81), described in the licensee's corrective action program as PIP O-05-5564.

b. Findings

Introduction: An URI was identified regarding the improper blocking of the ventilation paths into and out of Unit 3 Auxiliary Building Room 81 (Train B LPI/RBS pump room). The natural circulation ventilation pathways (circular stairs) are required for heat removal from the room during the recirculation phase following a loss of coolant accident (LOCA) to ensure the LPI and RBS pump and motor bearings do not exceed maximum operating temperatures. The issue will be documented as an Unresolved Item pending completion of a Phase 3 analysis.

Description: On August 30, 2005, the licensee generated PIP O-05-5564, which documents that a tent enclosure had been inappropriately installed in the Unit 3 portion of the Auxiliary Building and was blocking airflow from the stairway access into LPI/RBS pump room 81. The enclosure had been installed on about August 9, 2005, to allow for “lead” removal work in the room. The airflow pathway is credited in Oconee design calculation OSC-6667 for air movement and heat removal during design basis accidents (LOCA recirculation phase). OSC-6667 provides the various maximum room temperatures following an accident. Previous testing by the licensee found that relatively small increases in room temperature (<20 degrees F) above those calculated in OSC-6667, could render the LPI and RBS pumps inoperable. Consequently, since the air flow pathway credited in calculation OSC-6667 did not exist with the tent enclosure installed, the Unit 3 “B” train LPI and RBS pumps could not be considered operable during this period.

Analysis: The finding was considered to be a performance deficiency because the licensee failed to maintain the plant design in accordance with their design calculation OSC-6667 for design basis accidents, in that the assumed airflow pathway for heat removal was closed off. Since the LPI and RBS pumps cannot be considered operable in this condition, this finding was considered to be more than minor because it would impact the Reactor Safety Mitigating System Cornerstone for ensuring the availability, reliability and capability of a system that responds to initiating events to prevent undesirable consequences. A Phase 1 evaluation concluded that under the Mitigating Systems Cornerstone, the finding represented an actual loss of safety function of a single train for greater than its TS allowed time; therefore, a Phase 2 evaluation was required. The Phase 2 evaluation (dominated by small break loss of coolant accident) indicated that the issue was greater than Green and that a Phase 3 evaluation would be necessary. This finding involved the cross-cutting aspect of human performance.

Enforcement: 10 CFR 50, Appendix B, Criterion III, Design Control, requires in part that design changes, including field changes, are approved by the organization that performed the original design. Contrary to the above, a design change was made to the airflow pathway credited in design calculation OSC-6667 prior to obtaining approval from the licensee’s design organization. This issue was placed in the licensee’s corrective action program as PIP O-05-5564. Pending determination of the risk significance, this issue will be identified as URI 05000287/2005004-06, Inadequate Design Control of Unit 3 LPI/RBS Room Ventilation Pathways.

Cornerstone: Emergency Preparedness

1E6 Drill Evaluation

a. Inspection Scope

The inspectors observed and evaluated a simulator based emergency preparedness drill held on September 22, 2005. The drill scenario involved a security related event with postulated planted explosives. The scenario progressed to a general emergency after simulated damage to plant systems from various explosions. During the scenario, the operators were required to identify entry into an unusual event, alert and general emergency. The inspectors verified that the operators properly classified the event and made the appropriate notifications to the counties, state and NRC. The inspectors also verified that the protective action recommendations were issued in accordance with the licensee's emergency procedures. The inspectors reviewed the post drill critique to verify that the licensee captured any drill deficiencies or weaknesses.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

.1 Daily Screening of Corrective Action Reports

As required by Inspection Procedure (IP) 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed daily screening of items entered into the licensee's corrective action program. This review was accomplished by reviewing copies of PIPs, attending daily screening meetings, and accessing the licensee's computerized database.

.2 Semi-Annual Trend Review

a. Inspection Scope

As required by IP 71152, "Identification and Resolution of Problems," the inspectors performed a review of the licensee's Corrective Action Program (CAP) and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues; but, also considered the results of daily inspectors CAP item screenings discussed in Section 4OA2.1 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the six month period of March 2005 through September 2005, although some examples expanded beyond those dates when the scope of the trend warranted. The review also included issues documented outside the normal CAP in major equipment problem lists, plant health team vulnerability lists, focus area reports, system health reports, self-assessment reports, maintenance rule reports, and Safety Review Group monthly reports. The inspectors compared and contrasted their results with the results contained in the licensee's latest quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensees trend report were reviewed for adequacy.

b. Assessment and Observations

No findings of significance were identified. In general, the licensee has identified trends and has appropriately addressed the trends in the CAP. Inspection Report 05000269,270,287/2005003 documented a trend with regard to the generation of 23 PIPs for dropped flags on relays associated with various plant equipment during the previous six months. Following further inspection, this trend has been closed, as the increased documentation associated with this trend was part of the licensee's effort to investigate the cause of the dropped relay flags in conjunction with the relay manufacturer. Additionally, none of the specified relays have picked up, nor has there been any negative impact on plant equipment. The licensee and relay manufacturer continue to investigate this observation.

.3 Focused Review

a. Inspection Scope

The inspectors performed an in-depth review of an issue entered into the licensee's corrective action program. The sample was within the mitigating systems cornerstone and involved risk significant systems. The inspectors reviewed the actions taken to determine if the licensee had adequately addressed the following attributes:

- Complete, accurate, and timely identification of the problem
- Evaluation and disposition of operability and reportability issues
- Consideration of previous failures, extent of condition, generic or common cause implications
- Prioritization and resolution of the issue commensurate with safety significance
- Identification of the root cause and contributing causes of the problem
- Identification and implementation of corrective actions commensurate with the safety significance of the issue.

The following issue and corrective actions was reviewed:

- PIP O-05-4892, Unit 3, East to West Pen. Room Security/Fire Door Stuck shut

b. Findings

No findings of significance were identified.

.4 East Penetration Room Blowout Panel/HELB Issue

a. Inspection Scope

The inspectors performed a Problem Identification and Resolution (IP 71152) inspection for the implementation of the East Penetration Room blowout panel corrective actions related to NCV 05000269,270,287/2002004-02, Unauthorized Design Changes to the East Penetration Room Blowout Panels.

b. Findings

Introduction: The inspectors identified an URI for untimely corrective actions in resolving the East Penetration Room blowout panel issue. The blowout panels had been improperly modified, causing the plant to be outside the Oconee licensing basis for pressure relieving capacity for the panels and for flood mitigation panels not being assured of proper operation. This issue was previously documented as URI 05000269,270,287/2000008-04 and NCV 05000269,270,287/2002004-02. As of September 30, 2005, the blowout panels had not been repaired to ensure flood mitigation, nor had a license amendment been requested to correct the design pressure blowout capacity. This lack of corrective action was considered to be unresolved, pending completion of a Phase 3 analysis.

Description: In the fall of 1999, the inspectors noted that the blowout panels listed in the HELB licensing basis document OSC -73.2 (response to Giambusso Letter) had been epoxied and bolted in place. These panels were originally designed to limit the East Penetration Room pressurization following a main feed water or main steam line break or crack. In addition, the lower blowout panels were originally designed to allow water from the break or crack to leave the room and prevent flooding of safety-related equipment. As noted above, an URI was initiated in 2000 and an NCV was issued in 2002.

Subsequent to the NCV documented in 2002, the licensee determined that the blowout panels would not perform their design function to prevent flooding in the East Penetration Room. This condition is outside the licensing basis as specified in design document OSC-73.2. The licensee stated that modifications are necessary to prevent flooding of the auxiliary building because the East Penetration Room doors and block walls would likely fail during a HELB and the blowout panels are not assured of opening. The proposed modifications include installation of a knee wall to prevent flooding and installation of new blowout panels.

As of September 30, 2005, the licensee has not developed a modification or a schedule for bringing the three units back into compliance with the licensing basis. The guidance in GL 91-18, Attachment 1, Section 4.3, Current Licensing Basis and 10 CFR 50, Appendix B, states that, “If the licensee does not resolve the degraded or nonconforming condition at the first available opportunity or does not appropriately justify a longer completion schedule, the staff would conclude that corrective action has not been timely and would consider taking enforcement action.” This non-conforming condition was identified in 1999, but to date the licensee has not taken adequate and timely corrective action.

Analysis: The finding was considered to be a performance deficiency in that the licensee failed to implement timely corrective actions to repair the previously unauthorized modification of the East Penetration Room blowout panels. Since postulated flooding following a feedwater HELB would impact the HPI and emergency feedwater (EFW) functions, this finding was considered to be more than minor because it would impact the Reactor Safety Mitigating System Cornerstone for ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The Phase 1 evaluation was performed and it was concluded that under the Mitigating Systems Cornerstone that the finding represented an actual loss of a safety function of the HPI system, which required a Phase 2 evaluation. The Phase 2 evaluation (dominated by main steam line break) indicated that the issue was greater than Green and that a Phase 3 evaluation would be required. The previous Phase 3 analysis performed for NCV 05000269,270,287/ 2002004-02 found that the risk significance was Green. However, since that analysis, new information has been identified that may impact the significance of the issue. Therefore, a new Phase 3 analysis is necessary. This finding involved the cross-cutting aspect of Problem Identification and Resolution (PI&R).

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, requires in part that measures be established to assure that conditions adverse to quality, such as deficiencies, deviations, and non-conformances are promptly identified and corrected. Contrary to the above, Units 1, 2, and 3 have continued to be operated outside their licensing basis for meeting HELB criteria because the East Penetration Room blowout panels are not assured of opening to prevent auxiliary building flooding. In addition, the panels do not meet the design criteria for blowout capacity and corrective actions have not been taken in a timely manner to resolve the deficiency. Pending determination of the risk significance, this issue is being identified as URI 05000269,270,287/2005004-07, Untimely Corrective Actions in Correcting the East Penetration Room Blowout Panel Deficiency.

.5 Failure to Report the East Penetration Room Blow Out Panel Deficiency per 10 CFR 50.73

a. Inspection Scope

The inspectors reviewed the licensee’s operability evaluation and reportability evaluation related to improper modifications of the East Penetration Room blowout panels.

b. Findings

Introduction: An URI was identified regarding the failure to report a condition that could have prevented fulfillment of a safety function of a system as required by 10 CFR 50.73. The reportable condition was the improper modification of the East Penetration Room blow out panels which in their present condition would prevent the release of water following a feedwater HELB. Since the panels would not release the water outside the auxiliary building, leakage out of the room would eventually lead to flooding of the HPI pumps and this would prevent fulfillment of a safety function of a system (HPI) needed to place the plant in a cold shutdown condition. This issue is considered to be unresolved, pending determination of safety significance.

Description: In the late 1980's / early 1990's, the East Penetration Room blowout panels were coated with a metal shield elastomeric flasing compound followed by a polyester reinforcing fabric and then another coating of the metal shield elastomeric flasing compound. There is no information available on the physical strength or adhesion of the compounds. In addition, bolts and screws were installed on the outside of the panels to secure the panels in place. These undocumented modifications were implemented in order for the licensee to meet penetration room ventilation requirements for being able to draw a vacuum in the room. These modifications increased the panel blowout strength to values in excess of 144 pounds per square foot, although the licensing basis strength is limited to less than 63 pounds per square foot. Based on subsequent calculations, the licensee determined that the floor level blow out panels, that were designed to limit flooding in the auxiliary building, would not blow out under all conditions and flooding of the auxiliary building would occur.

In June 2004, the licensee made a presentation to Region II management. The presentation noted that the panels could not be assured of blowing out and plant modifications were needed to ensure flooding of the auxiliary building would not take place. This condition appeared to be reportable, so the licensee was asked to review the condition for reportability.

The licensee concluded that although there may be from 44,000 to 64,000 gallons of water available to flood the auxiliary building equipment, the floor drains would equalize the inventory between the Unit 1 and 2 HPI pump room and the Unit 3 HPI pump room, and none of the HPI pumps would be affected. In addition, the licensee assumed that the SSF makeup pump would be unaffected and would be able to stabilize the plant in hot standby. Based on these conditions, the licensee concluded that there would be no loss of safety function.

However, the inspectors found problems with the licensee’s analysis.

- Following a HELB, the plants licensing basis requires the licensee to go to cold shutdown. The SSF makeup pump cannot perform this function and is also not in the licensing basis to mitigate a HELB. Therefore, the HPI pumps are the only pumps that can be credited to provide the safety function to mitigate this accident and they must remain functional.

- The licensee inappropriately assumed that the HELB flood inventory would equalize between the Unit 1, 2, and Unit 3 HPI pump rooms. However, the inspectors noted that flooding of the HPI pump rooms is not limited by the floor drains as assumed in the licensee’s operability evaluation. The inspectors identified that each HPI pump room has a pipe chase that will direct flow into the room closest to the break. Therefore, the inspectors concluded that the available postulated flood inventory would cause flooding of the unit specific HPI pumps and render them inoperable.

- The licensee concluded that inventory from a postulated HELB crack would be 50,000 gallons and less than 20,000 gallons from a full break. This was based on operator action for the crack at 10 minutes and automatic feedwater isolation system (AFIS) actuation for a full break (<2 minutes). The inspectors noted that the licensee did not assume breaks sized between a crack and a full break, which would also not be isolated by an AFIS signal. The inspectors noted in the licensing basis (Giambusso letter) that the licensee is required to mitigate the effects from the worst case break, which in this case would be a break greater than a crack (5,000 gpm for 10 minutes), but less than a full break (13,000 gpm assumed to be isolated by AFIS in about 2 minutes). Based on this finding, the inspectors noted that the flood inventory would be much greater than analyzed by the licensee and would increase the probability of flooding in the HPI pump rooms

- The licensee assumed that AFIS would isolate a full break in less than 2 minutes. Because main steam headers are tied together, the inspectors noted that AFIS could not actuate on low steam pressure to isolate feedwater until there was a turbine trip. A turbine trip would require a reactor trip. Oconee does not have a SG low level trip. Therefore, discussions with the licensee indicated that the reactor trip needs to be initiated from a loss of feed water pumps. The only applicable feed water pump trip would be initiated on loss of suction pressure for >90 seconds. The inspectors noted that on a feedwater line break, feedwater flow would increase; thereby creating low feed pump suction pressures. The integrated control system would attempt to recover the proper feedwater flow by reducing the feedwater regulating valve position at a rate of 20 percent per minute or 30 percent over the first 90 seconds. The inspectors noted that with the feed water regulating valves at a position equivalent to 70 percent flow, feed water pump suction pressure would likely increase enough such that the low suction pressure trips would not occur. At lower volume breaks, feedwater pump trips are even less likely. Based on this discussion, the inspectors concluded that an AFIS isolation of the break is questionable and operator action at the licensing basis time of 10 minutes should be used for any flooding analysis.

Based on the above, the inspectors concluded that the licensee's operability evaluation was inadequate and that a single active failure (as postulated in the licensee's reportability analysis) was not required to cause a loss of the HPI pumps due to flooding. Therefore, the adverse condition of the blow out panels creating a situation where the HPI pumps (which are needed to mitigate a HELB) would be lost, was considered to be reportable per 10 CFR 50.73. The issue was discussed with the licensee. However, the licensee concluded that their evaluation was satisfactory.

<u>Analysis</u>: The issue was considered to be a performance deficiency in that the licensee failed to report a condition that could have prevented fulfillment of a safety function as required by 10 CFR 50.73. The failure to report has the potential to impact the NRC's ability to perform it's regulatory function. Therefore, this issue will be processed using traditional enforcement as specified in the Enforcement Policy IV.A.3. Determination of the safety significance by the Region II Senior Reactor Analyst will be necessary to determine the severity level of the violation.

<u>Enforcement</u>: 10 CFR 50.73, Part (v), requires the reporting of any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to (A) shutdown the reactor and maintain it in a safe shutdown condition

(licensing basis is cold shutdown) and (D) mitigate the consequences of an accident Contrary to the above, the licensee failed to report that improper modifications to the East Penetration Room blowout panels would prevent the fulfillment of the safety function of the HPI system to mitigate the consequences of a HELB accident (i.e., to shutdown the reactor and maintain it in a cold shutdown condition). Pending determination of the risk significance, this issue is being identified as URI 05000269,270,287/2005004-08, Failure to Meet the Reportability Requirements of 10 CFR 50.73 for the East Penetration Room Blow Out Panel Deficiency.

.6 Untimely Corrective Actions for Unit 2 East Penetration Room Floor Seal Deficiency

a. Inspection Scope:

While performing routine plant tours to identify any adverse plant conditions, the inspectors followed up on a previously noted damaged floor seal in the Unit 2 East Penetration Room.

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR 50 Appendix B, Section XVI, Corrective Action for inadequate corrective actions related to the lack of timeliness of repairs to a Unit 2 East Penetration Room floor seal. The inspectors concluded that the damaged floor seal, if left uncorrected could lead to flooding of safety-related equipment following a high energy line break in the Unit 2 East Penetration Room.

Description: On July 14, 2004, the licensee wrote a deficiency tag and work request on a partially extruded floor seal in the Unit 2 East Penetration Room. The affected floor seal fills a gap approximately 4 inches by six feet between two sections of reinforced concrete flooring in the room. The deficiency tag on the damaged seal was over a year old yet repairs had not been initiated. Further review found that the degraded condition had not been placed into the PIP process.

Analysis: The failure to promptly repair the damaged floor seal was considered to be a performance deficiency. The finding was considered to be more than minor because if left uncorrected, additional seal area could fail and it would affect the Mitigating System Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events, in that the HPI pumps could be flooded following a HELB in the East Penetration Room. However, in the seal's current level of degradation, the inspectors concluded that the deficiency would not by itself result in the loss of function of the HPI pumps, because flooding would be limited by the size of the degraded/failed seal. Consequently, the finding was determined to be of very low safety significance (Green), as it was screened out under the Mitigating Systems Cornerstone in the SDP Phase 1 Screening Worksheet with the determination that there was no loss of safety function. This finding involved the cross-cutting aspect of Problem Identification and Resolution.

Enforcement: 10 CFR 50 Appendix B, Section XVI, Corrective Action, requires **that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected**. Contrary to the above, the licensee failed to correct a partially extruded Unit 2 East Penetration Room floor seal that if left uncorrected, could degrade to the point that safety related equipment could be affected following a HELB. Because this issue was of very low safety significance and has been entered into the licensee's Corrective Action Program as PIP O-05-6097, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000270/ 2005004-09, Untimely Corrective Actions for Repairs to a Unit 2 East Penetration Room Floor Seal.

.7 Failure to Maintain Containment Electrical Penetration Enclosures

a. Inspection Scope

While performing routine plant tours to identify adverse plant conditions, the inspectors followed up on the observation that the containment electrical penetrations were degraded, in that cover plates were either missing or attached improperly.

b. Findings

Introduction: The inspectors identified an URI for failure to identify a condition adverse to quality in that East and West Penetration Room containment electrical penetrations enclosures had not been maintained as spray proof enclosures. Because these electrical enclosures have not been maintained, grounding and shorting of these circuits located in the East and West Penetration Rooms could lead to significant losses of safety-related electrical systems, controls and indications following a HELB. The issue will be documented as an URI pending further inspection.

Description: In June 2005, the inspectors identified that covers for a significant number of electrical penetrations were missing or improperly attached. These included specific penetrations which contained electrical circuits needed to mitigate the consequences of a high energy line break in the East Penetration Room and place the plant in a cold shutdown condition. Discussions with NRR concluded that the Oconee licensing basis requires the plant to be able to reach cold shutdown following a HELB while assuming one active failure. During discussions with the licensee, the licensee stated that the covers were not necessary to maintain the environmental qualification of the unprotected electrical circuits, and therefore, the as found degraded penetrations were acceptable to meet their safety function without the covers. Discussions with NRR concluded that the electrical penetrations would not meet their "as tested" environmental qualification if they could be impacted by direct or indirect spray and/or became dirty or rusted.

The inspectors noted that roughly 70 penetrations in the East Penetration Rooms had some sort of closure problem, and likely an equal number of problems in the West Penetration Rooms. The licensee initiated PIP O-05-4491 on July 9, 2005. The licensee also initiated repairs to the open penetration enclosures, which had still not been completed by the end of the inspection period.

The licensee performed an operability assessment and concluded that "The cables entering the electrical penetration assembly junction boxes do not require environmental sealing," and "all the electrical penetrations are outside the zone of influence for the two

HELB scenarios under consideration in the penetration rooms." The inspectors questioned why piping cracks would be outside the zone of influence and the engineers stated that the licensing basis for breaks or cracks did not include spray impingement, and therefore, did not have to be considered. Discussions with NRR concluded that the licensing basis for Oconee required not only spray, but direct jet impingement from postulated breaks. The breaks to be considered were cracks along the entire length of feedwater and steam line piping. The inspectors concluded that a postulated 13,000 gpm leak from a feedwater line break or 6,600 gpm leak from a feedwater line crack would affect the open penetrations and that the penetrations were required to be protected from the effects (i.e., direct or indirect spray) from a crack or break.

The inspectors observed debris and dust on the electrical terminal blocks inside the electrical penetration panels, rust on the terminal blocks and inside other components in the electrical penetration panels, and debris on top of the electrical penetration panels that would likely be washed into the panel during a postulated HELB. The inspectors also noted that with the covers missing/improperly installed, the terminal blocks could be sprayed down during a HELB. Based on an e-mail from NRR, Electrical Engineering Section, dated July 27, 2005, NRR concluded that terminal blocks are qualified for a harsh environment when not subjected to direct spray; where direct spray is anticipated, the terminal blocks are installed in enclosures. Oconee's commercial dedication for the safety-related terminal blocks required the terminal blocks to be installed in NEMA 4 enclosures (i.e., spray protected). NRR went on to state that cleanliness of the terminal blocks is required because accumulation of dirt and rust introduces a conductive path for current that could distort the signals from instrumentation circuits. Since the electrical penetration panels were not maintained, it was concluded by the inspectors that the original environmental qualification no longer encompassed the as found condition.

The inspectors concluded that multiple grounds and shorts would cause erratic actuation of alarm circuits and potentially cause unwarranted actuation/operation of emergency core cooling system and other plant equipment. These conditions would further hinder the ability of the operations staff to mitigate the HELB. The inspectors also concluded that the low voltage electrical systems were not designed to operate with multiple grounds and shorts and the likely affect would be to cause distortion of the instrumentation signals even on circuits that were not directly impacted by the HELB.

The inspectors noted that in the original licensing basis requirements, contained in the 1972 Giambusso letter, the licensee was required to verify that the rupture of a pipe carrying high energy fluid will not directly or indirectly result in loss of redundancy in any portion of the protection system, class 1E electrical system, engineered safety feature equipment, cable penetrations, or their interconnecting cables required to mitigate the consequences of the break and place the plant in cold shutdown. The licensee did not take exception to this requirement. The inspectors noted that many of the electrical penetrations needed to place the plant in hot standby were not being maintained. The inspectors concluded that the licensee was presently operating outside their licensing basis because a HELB in the East Penetration Rooms could cause a loss of redundancy of the circuitry needed to place the plant in hot standby. The listing of which penetrations would be needed to place the plant in cold shutdown are not known at this time because the licensee contends that they only have to ensure ability to go to hot standby and therefore do not have to meet the requirement for loss of redundancy in placing the plant in cold shutdown.

Analysis: The finding was considered to be a performance deficiency in that the licensee failed to maintain the containment electrical penetration covers as NEMA 4 enclosures. This finding was considered to be more than minor because direct and/or indirect spray from a HELB could affect multiple electrical circuits; thereby, increasing the likelihood of a reactor trip and that mitigation equipment would not be available. This would impact the Initiating Events Cornerstone objective to limit the likely hood of those events that upset plant stability, as well as the Mitigating Systems Cornerstone objective for ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

For the Phase 1 review, the inspectors concluded that the HELB could affect the unprotected reactor protection circuits and cause a reactor trip and affect circuits such as pressurizer level and steam generator pressure, which are used to mitigate the consequences of a HELB. Therefore, based on the Initiating Events Cornerstone for transient initiators, the inspectors concluded that the finding contributed to both the likelihood of a reactor trip and that mitigation equipment would not be available. These conditions required that a Phase 2 evaluation be performed.

Because the instrumentation circuits in the control room could be erratic due to the grounds and shorts resulting in degradation of the vital 120 vac and 120 vdc systems, and the inability to perform the various mitigation procedures due to erratic indications, it was assumed for the Phase 2 analysis that mitigation systems controlled from the control room were lost. Further inspection activities are being planned to support the analysis. This finding involved the cross-cutting aspect of Problem Identification and Resolution (PI&R).

Enforcement: 10 CFR 50 Appendix B, Criterion XVI, Corrective Action, requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, the license failed to identify and correct penetration covers that had been removed or misadjusted over a number of years of maintenance activities, which created conditions adverse to quality where dust, dirt, rust, and spray could impact circuits needed to mitigate the consequences of a HELB and cause erratic operation of the 120 vac and 120 vdc vital electrical systems. Pending further inspection and analysis, this issue is being identified as an Unresolved Item, URI 05000269,270,287/2005004-10, Failure to Maintain Containment Electrical Penetration Enclosures.

.8 Failure to Properly Identify Main Feedwater Line Terminal Ends

a. Inspection Scope

The inspectors performed a Problem Identification and Resolution inspection for the main feedwater system piping and supports located in the East Penetration Rooms. This inspection was chosen as part of the annual sample required by IP 71152. This issue is unresolved pending determination of risk determination.

b. Findings

Introduction: An URI was identified regarding the failure to identify a condition adverse to quality, in that feedwater terminal ends had not been identified and therefore actions to mitigate the affects from a terminal end line break had not been implemented.

Description: The Oconee licensing basis for high energy line breaks is contained in the 1972 Giambusso letter, which implemented GDC-4, and contained in the licensee's response to the Giambusso letter which is documented in Oconee MDS report No. OS-73.2, Analysis of Effects Resulting from Postulated Piping Breaks Outside Containment. The 1972 Giambusso Letter required the licensees to postulate breaks on ASME Class 1, 2 and 3 piping at the terminal ends. It required that "The plant should be designed so that the reactor can be shutdown and maintained in a safe shutdown condition in the event of a postulated rupture outside containment of a pipe containing a high energy fluid, including the double ended rupture of the largest piping in the main steam and feedwater systems. Plant structures, systems and components important to safety should be designed and located in the facility to accommodate the effects of such a postulated pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained."

An attachment to the letter defined terminal ends as extremities of piping that connect to structures, components or pipe anchors that act as rigid constraints to piping motion and thermal expansion. Rigid restraints that are welded to piping systems are considered to be terminal ends. The feedwater lines are restrained at the containment penetration by using a collar that is welded to the feedwater pipe with a structural anchor that is welded to the collar and attached to the containment structure. Since the collar weld acts as a rigid constraint to piping motion and thermal expansion, each welded location is considered to be a feedwater terminal end. However, the licensee only assumed a break upstream of the collar. The feedwater line has a whip restraint at this location to protect equipment in the East Penetration Room from the affects of this break. Since the licensee did not assume a break downstream of the collar, there is no equipment protection from a break at that location.

A feedwater line break downstream of the collar would result in a non-postulated/ unprotected feedwater line break in the East Penetration Room. The East Penetration Rooms are not designed for an unprotected feedwater line break and would be over pressurized. In addition, jet impingement and spray from the break would affect the electrical penetrations and other piping systems in the area of the break.

Discussions were held with the licensee concerning this issue. The licensee concluded that it is acceptable to assume that the terminal end line break can be taken at a location of the feedwater piping in the middle of the collar. This position was discussed with an NRR expert, but the licensee's position was not supported because the postulated terminal end break is required to be taken at the point of restriction. The inspectors concluded that the area in the middle of the collar could actually be an area with the lowest stress and likely would not see the full affects of thermal expansion and applied stress.

Analysis: The finding is considered to be a performance deficiency in that although it is a design deficiency, the licensee failed to identify the problem during the six years of HELB design reconstitution. An unprotected terminal end line break would cause overpressurization of the East Penetration Room, loss of circuitry needed to mitigate a HELB, flooding of the HPI pump rooms, and structural damage to the East Penetration Rooms. Structural damage, jet impingement, and spray would damage systems such as building spray, letdown, low pressure service water, low pressure injection, emergency feedwater, instrument air, etc, since for many of these systems both trains are routed through the East Penetration Rooms. Damage to these systems would impact the ability to reach cold shutdown conditions. This performance deficiency was considered to be more than minor because an unprotected terminal end line break would impact the Reactor Safety Mitigating Systems Cornerstone objective for ensuring the availability, reliability and function of systems needed to respond to a HELB. For the Phase 1 review, the inspectors concluded that an unprotected terminal end line break would result in a loss of safety function of the Auxiliary Building, the multiple mitigation safety systems listed above, and containment cooling and containment integrity from unrestrained feedwater piping thrust. This would therefore impact mitigation and containment integrity. Based on this, a Phase 2 evaluation was required. The Phase 2 sequence for main steam line break was used because the postulated break is between the feedwater check valve and the steam generator. A break at this location would be similar to a steam line break. Based on the assumptions that the Auxiliary Building would be damaged, electrical indication and control circuits would be damaged and systems located in the East Penetration Room would be damaged, the Phase 2 sheet for main steam line break indicated that the issue could be greater than Green and that a Phase 3 analysis would be required. This finding involved the cross-cutting aspect of Problem Identification and Resolution.

Enforcement: 10 CFR 50 Appendix B, Criterion XVI, Corrective Action, requires that measures shall be established to assure that conditions adverse to quality are promptly identified. Contrary to the above, the licensee failed to identify that unprotected feedwater line terminal ends existed that could impact the mitigation systems needed to protect the plant from a HELB. Pending determination of the risk significance, this issue is being identified as URI 05000269,270,287/2005004-11, Failure to Identify Unmitigated/Unprotected Feedwater Line Terminal Ends.

.9 Summary of PI&R Cross-Cutting Findings

A Green NCV involving the cross-cutting aspect of PI&R is documented in Section 1R22.2. The licensee failed to develop and implement a program for the inspection and cleaning of the containment electrical penetrations located in each units' East and West Penetration Rooms, delaying the possible identification of conditions adverse to quality.

A second Green NCV involving the cross-cutting aspect of human performance is documented in Section 1R22.3. Licensee personnel failed to develop and implement a program for the inspection of the main steam lines located in each units' East Penetration Rooms, delaying the possible identification of conditions adverse to quality.

A third Green NCV involving the cross-cutting aspect of PI&R is documented in Section 4OA2.6. The licensee failed to place a deficiency observed in the Unit 2 East

Penetration Room floor into the corrective action program, delaying the identification of a condition adverse to quality, as well as, its resolution.

A URI involving the cross-cutting aspect of PI&R is documented in Section 4OA2.4. The licensee failed to take prompt and adequate corrective action for a deficient condition within each units' East Penetration Rooms, that was identified in the Fall of 1999, resulting in all three Oconee Unit's operating outside their licensing basis since the unit's East Penetration Room blowout panels were improperly modified and have not been repaired.

A second URI involving the cross-cutting aspect of PI&R is documented in Section 4OA2.7. The licensee failed to identify a condition adverse to quality, in that, improperly maintained electrical penetration enclosures located within each units' East and West Penetration Rooms had not be identified and placed into the licensee's corrective action program; thereby, delaying resolution of this deficient condition.

A third URI involving the cross-cutting aspect of PI&R is documented in Section 4OA2.8. The licensee failed to identify a condition adverse to quality, in that, the feedwater piping terminal ends located within each units' East Penetration Room have not been properly identified.

4OA3 Event Followup

.1 Recent Events

a. Inspection Scope

The inspectors evaluated one licensee event and two degraded conditions for plant status and mitigating actions in order to provide input in determining the need for an Incident Investigation Team (IIT), Augmented Inspection Team (AIT), or Special Inspection (SI). As appropriate, the inspectors: (1) observed plant parameters and status, including mitigating systems/trains and fission product barriers; (2) determined alarms/conditions preceding or indicating the event; (3) evaluated performance of mitigating systems and licensee actions; (4) confirmed that the licensee properly classified the event in accordance with emergency action level procedures and made timely notifications to NRC and state/county governments, as required (10 CFR Parts 20, 50.9, 50.72); (5) communicated details regarding the event to management, risk analysts and others in the Region and Headquarters as input to their determining the need for an IIT, AIT, or SI.

- PIP O-05-5118, KHU-2 Emergency Lockout While Attempting to Generate to the Grid

- PIP O-05-5365, KHU- 2 Emergency Lockout While Performing PT/0/A/0620/016, Keowee Hydro Emergency Start Test

- PIP O-05-5613, Unit 3 Reactor Trip (SI documented in Inspection Report 05000287/2005010)

b. Findings

Except as identified in SI Inspection Report 05000287/2005010, no findings of significance were identified.

.2 (Closed) LER 05000269/2005-01-00, Exceeded TS: Emergency Power Path Aux Power Source Inoperable

The inspectors reviewed the circumstances surrounding the KHU overhead power path exceeding the TS allowed outage times due to a failed contactor for the overhead main step-up transformer cooling system normal power supply. The licensee also categorized this event as an unanalyzed condition due to a potential single failure vulnerability affecting both emergency power paths. This deficiency, its associated risk significance, and the licensee's corrective actions were documented in Inspection Report 05000269,270,287/2005003 as a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. This LER is closed.

.3 (Closed) LER 269/2004-04-01, Improper Overloads Installed on Control Room Ventilation Filter Train

a. Inspection Scope

The inspectors reviewed the licensee's TS LCO action statement entry, causal evaluation, corrective actions and operability assessment surrounding the unexpected tripping of the Unit 1 and 2, B Train, Control Room Outside Air Booster Fan (CROABF).

b. Findings

Introduction: A Green self-revealing NCV of 10 CFR 50 Appendix B, Criterion X, Inspection, was identified for an inadequate quality control (QC) inspection associated with the incorrect installation of the Unit 1 and 2 CROABF, B Train, motor thermal overload relays.

Description: On November 17, 2004, the filters of the B Train, outside air portion of the Unit 1 and 2 Control Room Ventilation System were replaced, and the associated booster fan's motor bearings were lubricated as part of a preventive maintenance task. During the subsequent post-maintenance testing, the fan tripped unexpectedly after 2.5 hours of operation. As documented in PIP O-04-7937, a licensee investigation determined that the apparent cause of the tripping of the B CROABF was the use of undersized heater overloads (S4.0) on the fan's motor. The fan's overloads were replaced with larger S4.4 heater overloads, and a 4 hour post-maintenance test was conducted satisfactorily. The inadequate design controls associated with this issue were previously documented as NCV 05000269/2005002-02, Improper Thermal Overloads Installed in the Unit 1 and 2, B Train, CROABF.

At 3 p.m. on April 10, 2005, the B CROABF was found tripped. Troubleshooting efforts revealed that the B CROABF center phase overload relay had tripped. The licensee's root cause evaluation concluded that the cause of the fan tripping was the off-center installation of S4.4 heater element within the thermal overload relay. This heater element was previously replaced as part of the recovery from the November 17, 2004, trip of the B CROABF. The replacement heaters were installed per IP/0/A/3011/015, Removal and Replacement of Motor Control Center, Panelboards and Remote Starter Components, which required the installer and QC inspectors to verify that the overload heaters were properly centered; however, the as-found heater position was off-center. As determined by subsequent testing, an off-center heater element will cause the overload relay to trip at a lower current than a relay with the heater element properly centered. The licensee replaced the S4.4 overload relay heater elements on the A and B CROABFs with S37.5 heater overloads, which are rated at 25 amps. The A and B CROABFs were then operated satisfactorily for 12 hours.

Analysis: The finding was considered to be a performance deficiency because the licensee failed to conduct an adequate QC inspection of the installation of the S4.4 overload relay heater elements on the safety-related B CROABF. The licensee's failure to correctly install the thermal overloads on the Unit 1 and 2, B Train, CROABF was considered to be more than minor because it affected the Barrier Integrity Cornerstone attribute of maintaining control room habitability. The inspectors reviewed this finding in accordance with IMC 0609, Significance Determination Process. Similar to NCV 05000269/2005002-02, this finding represented a similar degradation of the barrier function of the control room against smoke and/or a toxic atmosphere; thereby, requiring a Phase 3 evaluation be performed. However, since the exposure time associated with this CROABF finding is shorter than that used in the Phase 3 evaluation of NCV 05000269/2005002-02, it too is considered to be of very low safety significance (Green). This finding involved the cross-cutting aspect of human performance.

Enforcement: 10 CFR 50 Appendix B, Criterion X, Inspection, requires, in part, that inspection of activities affecting quality be executed in conformance with the documented instructions, procedures, and drawings. IP/0/A/3011/015 required that the overload heaters be installed correctly, centered, and inspected by QC. Contrary to the above, the licensee failed to perform adequate QC inspections of the Unit 1 and 2, B Train, CROABF, in that, the center phase thermal overload was not properly centered within the relay housing, resulting in the center phase overload tripping prematurely at a lower current than the fan's operating motor current. Because this issue was of very low safety significance and was placed in the licensee's corrective action program as PIP O-05-2361, this violation is being treated as an NCV in accordance with Section VI.A.1 of the Enforcement Policy: NCV 05000269,270/2005004-12, Inadequate QC Inspection Results in the Improper Installation of Thermal Overloads on the Unit 1 and 2 B Train, CROABF.

4OA4 Summary of Human Performance Cross-Cutting Findings

A Green Finding involving the cross-cutting aspect of human performance is documented in Section 1R13. Licensee personnel failed to fully understand the scope of maintenance on a Unit 3 secondary system makeup valve, resulting in an inadequate maintenance tagout. This nearly resulted in a Unit 3 trip with a loss of normal heat sink.

A Green NCV involving the cross-cutting aspect of human performance is documented in Section 4OA3.3. A licensee QC inspectors failed to properly inspect the installation of a heater element within the thermal overload relay for the Unit 1 and 2, B Train CROABF, resulting in the overload relay tripping at a reduced current.

A URI involving the cross-cutting aspect of human performance is documented in Section1R14. Licensee personnel failed to update procedural guidance for the control of the newly installed equipment, Unit 3, SSF-powered Pressurizer Heater Bank 2, Group C, resulting in the supply breaker, PXSF-4A, not being closed prior to entering Mode 3.

A second URI involving the cross-cutting aspect of human performance is documented in Section 1R23. Licensee personnel improperly blocked the ventilation paths into and out of Auxiliary Building Room 81 (Train B, LPI/RBS pump room). This ventilation path is required for heat removal from the room during the recirculation phase of a LOCA to ensure that the LPI and RBS pump and motor bearings do not exceed maximum operating temperatures.

4OA5 Other Activities

Operational Readiness of Offsite Power (Temporary Instruction (TI) 2515/163)

Completion of this TI was documented in Inspection Report 05000269,270,287/2005003. However, after NRC headquarters review of the information provided, additional information related to the TI was requested. The inspectors collected this information from licensee discussions, site procedures, and other licensee documentation. The information was provided to the headquarters staff for further analysis.

4OA6 Management Meetings (Including Exit Meeting)

.1 Exit Meeting Summary

The inspectors presented the inspection results to Mr. Bruce Hamilton, Station Manager, and other members of licensee management at the conclusion of the inspection on October 4, 2005. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Regulatory Performance Meeting Summary

On September 20, 2005, NRC Region II (RII) held an Oconee regulatory performance meeting with Duke Energy to discuss the results of a supplemental inspection (IR 05000269,270,287/2005010) conducted May 31 - June 2, 2005. That inspection assessed the licensee's problem identification, root cause evaluation, extent of condition determination, and corrective actions associated with two White findings in the Mitigating Systems Cornerstone, which placed the performance of Oconee Units 1, 2 and 3 in the Degraded Cornerstone Column of the NRC's Action Matrix for the third quarter 2004. The two findings involved: (1) pressurizer ambient heat losses in all three Oconee units exceeding the capacity of the pressurizer heaters powered from the SSF; and (2) procedural criteria for manning the SSF during a fire in certain areas. The meeting focused on the corrective actions associated with these White findings, as well as with the supplemental inspection, in order to arrive at a shared understanding of the performance issues, underlying causes, and planned licensee actions.

This meeting was opened to the public. Attendees included: Oconee site management and staff (indicated on the Attachment to this report); NRC Region II management (indicated on Attachment to this report); and the resident inspectors. The presentation material used for the discussion is available from the NRC's document system (ADAMS) as Accession Number ML052650202. ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

L. Azzarello, Modification Engineering Manager
S. Batson, Superintendent of Operations
D. Baxter, Engineering Manager
R. Brown, Emergency Preparedness Manager
S. Capps, Mechanical/Civil Engineering Manager
N. Clarkson, Regulatory Compliance*
N. Constance, Operations Training Manager
C. Curry, Maintenance Manager
G. Davenport, Compliance Manager
C. Eflin, Requalification Supervisor
T. Gillespie, Reactor and Electrical Systems Manager
T. Grant, Engineering Supervisor, Reactor & Electrical Systems
R. Griffith, QA Manager
B. Hamilton, Station Manager*
D. Hubbard, Training Manager
R. Jones, Site Vice President*
T. King, Security Manager
L. Nicholson, Safety Assurance Manager*
B. Spear, Engineer, Reactor & Electrical Systems
J. Twiggs, Manager, Radiation Protection
J. Weast, Regulatory Compliance*

NRC

M. Ernstes, Chief of Reactor Projects Branch 1*
C. Casto, Director RII Division of Reactor Projects*
W. Travers, Regional Administrator, RII

*Note: Personnel indicated with an asterisk attended the regulatory performance meeting on September 20, 2005. (See section 4OA6.2 for further details.)

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000287/2005004-03	URI	Failure to Maintain Design Control of the SSF Supply Power Breaker for Unit 3, Bank 2, Group C Pressurizer Heaters (Section 1R14)
05000287/2005004-06	URI	Inadequate Design Control of Unit 3 LPI/RBS Room Ventilation Pathways (Section 1R23)
05000269,270,287/2005004-07	URI	Untimely Corrective Actions in Correcting the East Penetration Room Blowout Panel Deficiency (Section 4OA2.4)
05000269,270,287/2005004-08	URI	Failure to Meet the Reportability Requirements of 10 CFR 50.73 for the East Penetration Room Blow Out Panel Deficiency (Section 4OA2.5)
05000269,270,287/2005004-10	URI	Failure to Maintain Containment Electrical Penetration Enclosures (Section 4OA2.7)
05000269,270,287/2005005-11	URI	Failure to Identify Unmitigated/Unprotected Feedwater Line Terminal Ends (Section 4OA2.8)

Opened and Closed

05000269,270,287/2005004-01	NCV	Performing Licensed Duties While Medically Unqualified (Section 1R11.2)
05000287/2005004-02	FIN	Inadequate Maintenance and Oversight Increased the Likelihood of a Unit 3 Reactor Trip with a Loss of Normal Heat Sink (Section 1R13)
05000269,270,287/2005004-04	NCV	Failure to Develop and Implement a Cleanliness Inspection Program for the Containment Electrical Penetrations (Section 1R22.2)
05000269,270,287/2005004-05	NCV	Failure to Implement an Inspection Program for the Main Steam Lines (Section 1R22.3)

05000270/2005004-09	NCV	Untimely Corrective Actions for Repairs to a Unit 2 East Penetration Room Floor Seal (Section 4OA2.6)
05000269,270/2005004-12	NCV	Inadequate QC Inspection Results in the Improper Installation of Thermal Overloads on the Unit 1 and 2, B Train, CROABF (Section 4OA3.3)

Closed

05000269/2005-01-00	LER	Exceeded Tech Spec: Emergency Power Path Aux Power Source Inoperable (Section 4OA3.2)
05000269/2004-04-01	LER	Improper Overloads Installed on Control Room Ventilation Filter Train (Section 4OA3.3)

Items Discussed

2515/163	TI	Operational Readiness of Offsite Power (Section 4OA5)

DOCUMENTS REVIEWED

Section 1R11.2: Requalification Program

2003-2004 LOR Program Grades
2003-2004 LOR Program Grades
2005 Biennal Written Exams
Scenario ASE-07, Small Break LOCA
Scenario ASE-10, Large break LOCA
Scenario ASE-13, Loss of Feed and HPI Cooling
Scenario ASE-24, Main Steam Line Break
Badge Access Transaction Reports for Reactivation of Licenses (3)
Licensed Operator Medical Records (30)
Feedback Summaries
Human Performance Errors

Remedial Training Records:
- Inspectors reviewed six remedial training records and four borderline passes on the biennial written exam.

Written Exams Reviewed:
- RO/SRO 2005 LOCT Annual Exam B Shift
- RO/SRO 2005 LOCT Annual Exam D Shift

Simulator Performance Transient Tests:
- PT/T/01: Anticipatory Reactor trip on Loss of Main Feedwater
- PT/T/03: Loss of Offsite Power
- PT/T/05: Turbine Trip from 30% power Without Automatic Reactor Trip

Simulator Performance Transient Tests:
- PT/N/03: 100%, 53%, and 15% Parameter Verifiaction

Simulator Scenario Based Testing:
- Scenario ASE-10, Large break LOCA
- Scenario ASE-13, Loss of Feed and HPI Cooling
- Scenario ASE-23, LOCA, LOSP
- Scenario ASE-24, Main Steam Line Break

Simulator Maintenance and configuration:
- OTG - 010, Training Materials Development and Maintenance, Rev 12
- OTG - 012, Oconee Training Center Simulator Configuration Management Guide, Rev 12

LIST OF ACRONYMS

ACB	-	Air Circuit Breaker
ADAMS	-	Agency wide Documents Access and Management System
AFIS	-	Automatic Feedwater Isolation System
AIT	-	Augmented Inspection Team
ASME	-	American Society of Mechanical Engineers
ASW	-	Auxiliary Service Water
BP	-	Blood Pressure
CAP	-	Corrective Action Program
CFR	-	Code of Federal Regulations
CRD	-	Control Rod Drive
CROABF	-	Control Room Outside Air Booster Fan
DEC	-	Duke Energy Corporation
DG	-	Diesel Generator
EOC	-	End-of-Cycle
GPM	-	Gallons per Minute
HELB	-	High Energy Line Break
HPI	-	High Pressure Injection
HPSW	-	High Pressure Service Water
ICS	-	Integrated Control
IIT	-	Incident Investigation Team
IN	-	Information Notice
IP	-	Inspection Procedure
IR	-	Inspection Report
JPM	-	Job Performance Measure
KHU	-	Keowee Hydroelectric Unit
kV	-	Kilo Volt
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accident
LOR	-	Licensed Operator Requalification
LPI	-	Low Pressure Injection
LPSW	-	Low Pressure Service Water
NCV	-	Non-Cited Violation
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
ONS	-	Oconee Nuclear Station
OOS	-	Out of Service
OPS	-	Operations
PARS	-	Publicly Available Records
PI&R	-	Problem Identification and Resolution
PIP	-	Problem Investigation Process report
PMT	-	Post-Maintenance Testing
PT	-	Performance Test
QC	-	Quality Control

RBS	-	Reactor Building Spray
RCS	-	Reactor Coolant System
RFO	-	Refueling Outage
RII	-	Region II
RTP	-	Rated Thermal Power
SDP	-	Significance Determination Process
SI	-	Special Inspection
SRO	-	Senior Reactor Operator
SSC	-	Structure, System and Component
SSF	-	Standby Shutdown Facility
TI	-	Temporary Instruction
TS	-	Technical Specification
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
UST	-	Upper Surge Tank
WCC	-	Work Control Center