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

July 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 05000269/2005003, 05000270/2005003, 05000287/2005003

Dear Mr. Jones:

On June 30, 2005, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Oconee Nuclear Station. The enclosed report documents the inspection findings which were discussed on July 6, 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.

Based on the results of this inspection, the NRC has determined that one Severity Level IV violation of NRC requirements occurred. The NRC has also identified two self-revealing findings and two NRC identified findings of very low safety significance (Green), three 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 findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV 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 05000269/2005003, 05000270/2005003, 05000287/2005003 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:	50-269/2005003, 50-270/2005003, 50-287/2005003
Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7800 Rochester Highway Seneca, SC 29672
Dates:	April 1, 2005 - June 30, 2005
Inspectors:	M. Shannon, Senior Resident Inspector A. Hutto, Resident Inspector E. Riggs, Resident Inspector G. Laska, Senior Operation Examiner (Section 1R11.2) J. Fuller, Reactor Inspector (Sections 1R08 and 4OA5.3) P. Fillion, Reactor Inspector (Section 4OA2.3) A. Vargas-Mendez, Reactor Inspector (Sections 1R08 and 4OA5.3) L. Miller, Senior Emergency Preparedness Inspector (Sections 1EP2-1EP5 and 4OA1) H. Gepford, Health Physicist (Section 4OA5.4)
Accompanying Personnel:	J. Blake, Steam Generator Consultant (Section 1R08)
Approved by:	Michael E. Ernstes, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000269/2005003, IR 05000270/2005003, IR 05000287/2005003, 04/01/2005 - 06/30/2005; Oconee Nuclear Station, Units 1, 2, and 3; Identification and Resolution of Problems and Event Followup.

The report covered a three-month period of inspection by the onsite resident inspectors and announced regional-based inspections conducted by two reactor inspectors, an operation examiner, an emergency preparedness inspector, a health physicist and a steam generator consultant. One Severity Level IV non-cited violation (NCV), three Green NCVs, and a Green finding 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 NRC-identified non-cited violation of Technical Specification (TS) 5.4.1 was identified for failure to follow the procedure requirements in replacing the Seismic Trigger System batteries.

  The inspectors determined that the failure to follow procedure in replacing the batteries as required, the inadequate procedure for centering the masses, and use of an unapproved procedure to perform the calibrations collectively represented a performance deficiency because the licensee is required to follow procedures, have procedures with adequate acceptance criteria and to use approved procedures. The finding was considered to be more than minor in that it was concluded by the inspectors that failure to follow the procedure requirements of replacing the batteries could render the seismic switch and therefore, the seismic monitors inoperable, if the batteries failed after their expiration dates. Thus if left uncorrected the finding would become a more significant safety concern because this equipment is used to determine whether or not the units need to be shutdown following a seismic event. In addition, it was concluded that the finding affected the reliability of systems that respond to initiating events in that it could affect the post event operating procedures (Abnormal Operating Procedures (AOPs) and Emergency Operating Procedures (EOPs)) for responding to a seismic event. The finding was screened using the Phase 1 screening criteria specified under Seismic, Flooding and Severe Weather Screening Criteria. The inspectors concluded that whether or not the failure to replace the batteries represented a degradation of equipment, since the finding did not represent an actual loss of function, the issue would be screened as Green by Questions 2 and/or 3 of this section. (Section 1R22)

Cornerstone: Barrier Integrity

- Green. A self-revealing non-cited violation of 10 CFR 50.49 (Environmental Qualification) was identified for allowing the terminal block associated with valve 1HP-21 to deteriorate (rust) beyond its qualified tested condition; thereby, creating a situation where this containment isolation valve may not have been able to fulfill its design function to close in a harsh environment.

  This performance deficiency is more than minor because it is associated with the cornerstone attribute of containment isolation system reliability and availability, as well as the cornerstone objective of providing a physical barrier (containment) to protect the public from a radio nuclide release. The finding was determined to be of very low safety significance because the leak past containment through 1HP-21, Reactor Coolant Pump Seal Return Line Isolation Valve, would be into a closed system and there was an unaffected redundant valve to perform the isolation function. (Section 4OA2.3b.(4))

- Green. A self-revealing finding was identified for an inadequate design change when the licensee replaced the Unit 1 reactor coolant pump (RCP) Westinghouse seals with Sulzer seals during the 2000 fall refueling outage (RFO 19).

  The finding was considered to be more than minor because it affected the initiating events cornerstone, in that the Number 3 seal leakage affected the cornerstone objective to limit the likelihood of those events (specifically a seal loss of coolant accident (LOCA)) that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The Phase 1 question under the initiating events cornerstone for primary system LOCA initiators was answered yes, as it was assumed that worst case degradation of the seals would exceed the TS limit for reactor coolant system (RCS) leakage; therefore, a Phase 2 analysis was required. For the Phase 2 analysis, scenarios that result in loss of all seal cooling were considered and a seal LOCA assumed with no recovery credit. The Phase 2 analysis exceeded the threshold that required evaluation under Phase 3 of the SDP. A regional SRA performed a Phase 3 evaluation. The results of this analysis were also green based on analysis of the dominant accident sequences which involved a high energy line break in the turbine building that fails all the safety related 4160 VAC buses, thus requiring the Safe Shutdown Facility (SSF) to be placed into service and consequently, the Reactor Coolant Makeup Pump function fails and an Reactor Coolant Pump (RCP) Seal loss of coolant ensues. Based on the Phase 3 analysis, the finding was determined to be of very low safety significance (green). (Section 4OA5.2)

Cornerstone: Mitigating Systems

- Green. A NRC-identified non-cited violation of 10 CFR 50 Appendix B, Criterion XVI, Corrective Action, was identified for inadequate corrective actions related to the timeliness of identification of a failed electrical contactor supplying one train of power to the Keowee Hydro Unit (KHU) main step-up transformer cooling systems, resulting in a reduction in reliability of the KHU overhead power path.

The finding was considered to be more than minor because it affected the mitigating system cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events in that the reliability of the KHU overhead emergency power path was reduced for approximately a three week period. However, the cooling power to the transformer was maintained during this period; therefore, there was no actual loss of safety function for either the underground or overhead emergency power path. Consequently the finding was determined to be of very low safety significance. This finding also involved the cross-cutting aspect of problem identification and resolution. (Section 4OA2.3)

Cornerstone: Emergency Preparedness

- No Color. A Severity Level IV non-cited violation (NCV) was identified for implementing a change which decreased the effectiveness of the emergency plan without prior NRC approval, contrary to the requirements of 10 CFR 50.54(q). The change involved Emergency Action Level 4.7.U.2.1 classification of “Natural Disasters, Hazards and Other Conditions Affecting Plant Safety.”

  The finding was evaluated using the NRC’s Enforcement Policy because licensee reductions in the effectiveness of its emergency plan impact the regulatory process. This finding has greater than minor significance in that the change extends the event time allowed prior to appropriate emergency classification of a natural disaster which could adversely affect the performance of both onsite and offsite emergency actions. The finding was determined to be a non-cited Severity Level IV violation because it involved licensee failure to meet an emergency planning requirement not directly related to assessment and notification. (Section 1EP4)

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 shutdown from approximately 100 percent RTP on April 9, 2005, and commenced the 1 EOC-22 RFO. The unit was brought on-line on May 15, 2005, and achieved 100 percent RTP on May 17, 2005. 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 April 17, 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 3 entered the report period at 100 percent RTP. The unit was reduced to approximately 85 percent RTP on April 20, 2005, to repair a heater drain pump; subsequently, the unit was returned to 100 percent RTP on April 22, 2005. The unit was reduced to approximately 88 percent RTP on May 22, 2005, to perform startup testing of the unit's Triconex Electro-Hydraulic Control (EHC) upgrade. The unit was returned to 100 percent RTP on the same day. The unit was reduced to approximately 87 percent RTP on June 24, 2005, due to the failure of a heater drain pump discharge flow control valve. The heater drain system was restored on June 28, 2005, and the unit was returned to 100 RTP on June 29, 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 Warning

a. Inspection Scope

The inspectors verified that the licensee responded appropriately to a tornado warning issued for Pickens County, SC when a doppler radar indicated tornado was projected to pass through Pickens and Liberty, SC on April 22, 2005. Pickens is located approximately 11 miles northeast of the plant, and Liberty is located approximately 11 miles east of the plant. 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 5.2, Tornado Warning, as required by the AP. The inspectors verified that all control room operations personnel had reviewed Enclosure 5.1, Tornado Information, as required by the AP.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

Partial Walkdown

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:

- KHU-2, CT-4 and the Underground Power Path with CT-5 Out of Service (OOS) for Preventive Maintenance (PM)

- B HPSW Pump with the A HPSW Pump OOS for Realignment

- Unit 1, 2 and 3 Turbine Driven Emergency Feedwater (TDEFW) Pumps, Station Auxiliary Service Water Pump, Unit 1, 2 and 3 Blockhouses, and KHUs with the Standby Shutdown Facility (SSF) OOS due the SSF Diesel Generator Tripping on Overcurrent (Problem Investigation Process report (PIP) O-05-3670)

b. Findings

No findings of significance were identified.

1R05 Fire Protection

Fire Area Walkdowns

a. Inspection Scope

The inspectors conducted tours in nine 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:

- Impairment to Unit 1 Cable Room Fire Barrier, 1-C-F-59 (1)
- Impairment to Unit 1 Cable Room Fire Barrier, 1-C-F-76 (1)

- Unit 1 EHC Drums Stored in a Turbine Building Basement Fire Area (1)
- Unit 1, 2, 3 Control Battery Rooms (3)
- Radwaste Facility (1)
- Unit 1, 2 and 3 Blockhouses (2)

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

.1 External Flooding (Turbine Building)

a. Inspection Scope

On April 22, 2005, during heavy rains associated with a severe thunderstorm, the inspectors toured the turbine building to verify that barriers to external flooding were intact, and that additional preparations for the forecasted weather conditions had been undertaken. During the storm, the inspectors verified cable trenches were being pumped as necessary and building cable and piping penetrations were not leaking excessively. The inspectors also verified that the licensee identified problems and entered them into the corrective action program at the appropriate level.

b. Findings

No findings of significance were identified.

.2 Internal Flooding (Turbine Building)

a. Inspection Scope

The inspectors reviewed the licensee's turbine building flood control measures while performing Unit 1 condenser repairs during its refueling outage commencing in April 2005. The inspectors determined that the licensee complied with the applicable Unit 1 waterbox and condenser cooling water (CCW) inlet and outlet de-watering and watering operating procedures (OP/1/A/1104/012 E and G). The inspectors also walked down the appropriate CCW valve isolations to verify that they were established per Selected Licensee Commitments 16.9.11.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities

.1 Piping Systems ISI

a. Inspection Scope

The inspectors reviewed the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries for Unit 1. The inspectors selected a sample of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of inspection procedure 71111.08, "Inservice Inspection Activities," based upon the ISI activities available for review during the onsite inspection period.

The inspectors conducted an on-site review of nondestructive examination (NDE) activities to evaluate compliance with Technical Specifications (TS), ASME Section XI, and ASME Section V requirements, 1998 Edition through 2000 Addenda, and to verify that indications and defects (if present) were appropriately evaluated and dispositioned in accordance with the requirements of ASME Section XI, IWB-3000 or IWC-3000 acceptance standards.

Specifically, the inspectors observed the following examination:

Ultrasonic Testing (UT):
- 1-FDW88-C, Main Feedwater Elbow to Pipe Weld, ASME Class 2

Specifically, the inspectors reviewed the following examination records:

Ultrasonic Testing (UT):
- 1-RPV-WR19, Reactor Head Flange to Reactor Vessel Nozzle Belt, ASME Class 1
- 1-PZR-WP26-7, Pressurizer Nozzle to Shell, ASME Class 1
- 1-PZR-WP26-3, Pressurizer Nozzle to Shell, ASME Class 1

Visual Testing (VT):
- 1-PZR-WP91-1, 2.5" Nozzle to stainless steel Pressurizer Relief Valve Flange, ASME Class 1
- 1-PZR-WP91-2, 2.5" Nozzle to stainless steel Pressurizer Relief Valve Flange, ASME Class 1
- 1-PZR-WP91-3, 2.5" Nozzle to stainless steel Pressurizer Relief Valve Flange, ASME Class 1
- 1-PZR-WP-63-7, Between Nozzle and Safe End on 1" Sampling Line, ASME Class 1
- 1-PZR-WP63-1 through 1-PZR-WP63-6, Pressurizer Nozzle to Safe End welds for 1" Level Instrument Taps, ASME Class 1
- 1-RC-RD-0043, 1.5" Thermoweld Annulus area, ASME Class 1
- 1-50-5-1, 1" Vent, ASME Class 1

- 1PSP-1, 4" Spray Nozzle Safe End to Stainless Steel Piping, ASME Class 1
- 1-PZR-WP-45, Safe End to 4" Pressurizer Spray Nozzle, ASME Class 1

Liquid Penetrant Testing (PT):
- 1-RPV-CRD-57WH9, CRDM Housing Body to Adapter, ASME Class 1
- 1-RPV-CRD-57W60, CRDM Base to Motor Tube, ASME Class 1
- 1-RPV-CRD-57, CRDM Motor Tube to Extension, ASME Class 1
- 1-RPV-CRD-57W61, CRDM Extension to Cap, ASME Class 1

Radiographic Examination (RT)
- 1-HP-0479-93, ASME Class 2
- 1-RC-0270-189V, ASME Class 1, 1" Hot Leg Vent
- 1-RC-0267-179V, ASME Class 1, 1" Hot Leg Vent
- HPI Nozzle 1A1, Thermal Sleeve Examination
- HPI Nozzle 1B2, Thermal Sleeve Examination

The Inspectors reviewed examination records for the following recordable indications to evaluate if the licensee's acceptance was in accordance with acceptance standards contained in Article IWB-3000 of ASME Section XI.

Ultrasonic Testing (UT):
- 1-FDW88-C, Main Feedwater Elbow to Pipe Weld, ASME Class 2
- 1MS-076-12V, Steam Generator 1 A, Reducer to Nozzle, ASME Class 2
- 1-PIA1-7, Transition Piece to Pipe, ASME Class 1
- 1LP-140-1A, Decay Heat Removal, Pipe to Nozzle, ASME Class 1
- 1LP-140-8A, Decay Heat Removal, Elbow to Valve (1LP-1), ASME Class 1

Liquid Penetrant Testing (PT):
- 1-PIA1-7, Transition Piece to Pipe, ASME Class 1
- 1-PZR-WP91-2, Nozzle to Safe End, ASME Class 1
- 1-PZR-WP91-3, Nozzle to Safe End, ASME Class 1

The inspectors reviewed the “Owner's Report For Inservice Inspections, Oconee Unit 1, 2003 Refueling Outage, EOC 21,” dated March 29, 2004, which stated that there was one reportable item from last outage; hanger 1-01A-R10 was found to be inoperable. The inspectors reviewed the evaluation and applicable corrective action documentation to ensure that the failure was not service induced and that the licensee has taken appropriate actions to prevent a reoccurrence.

Qualification and certification records for examiners, inspection equipment, and consumables along with the applicable NDE procedures for the above ISI examination activities were reviewed and compared to requirements stated in ASME Section V and Section XI.

A pressure boundary welding activity associated with ASME Class 2 components was reviewed, to verify the welding process and examinations were performed in accordance with the ASME Code Sections III, V, IX, and XI requirements. The inspectors reviewed weld data sheets, the welding procedure specification (WPS), supporting welding procedure qualification records (PQR), welder qualification records, and preservice examination (PSI) results for the following weld:

- 1-HP-0479-93, 4" Stainless Steel, ASME Class 2, and associated Weld Repair

The inspectors performed a review of piping system and Steam Generator ISI related problems that were identified by the licensee and entered into the corrective action program. The inspectors reviewed these corrective action documents to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspectors' review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The inspectors evaluated the threshold for identifying issues through interviews with licensee staff and review of licensee actions to incorporate lessons learned from industry issues related to the ISI program. The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

The inspectors reviewed the licensee's BACC program to ensure compliance with commitments made in response to NRC Generic Letter 88-05 "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary" and Bulletin 2002-01 "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity."

The inspectors conducted an on-site record review as well as an independent walk-down of parts of the reactor building that are not normally accessible during at-power operations to evaluate compliance with licensee BACC program requirements and 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. In particular, the inspectors verified that the visual examinations focused on locations where boric acid leaks can cause degradation of safety significant components and that degraded or non-conforming conditions were properly identified in the licensee's corrective action system.

The inspectors reviewed a sample of engineering evaluations completed for boric acid found on reactor coolant system piping and components to verify that the minimum design code required section thickness had been maintained for the affected component(s). The inspectors also reviewed licencee corrective actions implemented for evidence of boric acid leakage to confirm that they were consistent with requirements of Section XI of the ASME Code and 10 CFR 50 Appendix B Criterion XVI. Specifically, the inspectors reviewed:

- O-05-02810, Boron Observed in between body to bonnet flange connection of 1HP-194
- O-05-2320, Unit 1 Reactor Building Walk Down Results, 1 RC IV 0028 and Incore Plug Fitting Leaks

b. Findings

No findings of significance were identified.

.3 Steam Generator (SG) Tube ISI

a. Inspection Scope

The inspectors reviewed the Unit 1 SG tube examination activities conducted pursuant to Technical Specification (TS) and the ASME Code Section XI requirements.

The inspectors reviewed the SG examination scope, eddy current testing (ET) acquisition procedures, ET analysis procedures, the SG Operational Assessment, records and examination reports to confirm that:

- The SG tube ET (Eddy Current Testing) examination scope was sufficient to identify tube degradation confirming that the ET scope completed was consistent with the licensee's procedures and plant TS requirements. Additionally, the inspectors reviewed the SG tube ET examination scope to determine that it was consistent with that recommended in EPRI "Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6" and included tube areas which represent ET challenges such as the tubesheet regions, expansion transitions and support plates.

- The licensee adequately followed-up on a new tube degradation mechanism other than what was predicted in the SG tube degradation assessment, specifically unexpected wear at locations between the 8^{th} and 12^{th} support plates.

- The SG tube repair criteria and process (plugging and sleeving) was consistent with TS requirements and the licensee was only applying the TS plugging limit at tube wear locations.

- The ET probes and equipment configurations used to acquire ET data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H "Performance Demonstration for Eddy Current Examination" of EPRI "Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6."

- The licensee adequately examined for loose parts indications.

- The licensee adequately evaluated for any contractor deviations from their ET data acquisition or analysis procedures or EPRI "Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6."

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Quarterly Training Observation

a. Inspection Scope

The inspectors observed licensed operator simulator training on June 22, 2005. The training focused on plant transient response at low power operation. The simulator scenarios included a continuous rod withdrawal transient at three percent RTP followed by integrated control system controlling Tave instrument failing high at 18 percent RTP. The training concluded with a full power plant transient response where various low condensate booster pump and main feedwater pump low suction pressure runbacks were simulated. 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 also attended the post training critique to verify that any observed problems were identified and discussed with the operating crew.

b. Findings

No findings of significance were identified.

.2 Annual Review of Licensee Requalification Examination Results.

a. Inspection Scope

On April 1, 2005, the licensee completed the comprehensive requalification biennial written examinations and annual operating tests, required to be given to all licensed operators by 10 CFR 55.59(a)(2). The inspectors performed an in-office review of the overall pass/fail results of the written examinations, individual operating tests, and the crew simulator operating tests. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

No findings of significance were identified.

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:

- PIP O-05-2582, Damage to the 1A1 RCP Seal
- PIP O-05-3495, A HPSW Pump alignment is not within acceptable limits

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.

- Orange ORAM Risk Condition, Complex Plan for 1LP-19 Cable Separation
- Orange Shutdown Risk, Draining Unit 1 RCS to Mid-Loop Conditions During 1EOC-22
- PIP O-05-3438, Discrepancy Between Innage Special Emphasis Report Risk Status and Results of STA Performing a Risk Assessment
- PIP O-05-3599, KHU Main Transformer Cooling Fan Primary Power Supply Contractor cannot Function
- PIP O-05-3670, SSF Diesel Generator Tripped on Overcurrent
- Red ORAM Risk Condition with KHU Overhead OOS and SSF Diesel Generator Tripped on Overcurrent (PIP O-05-4284)
- Orange ORAM Risk Condition, 1LP-21 Electro-Mechanical PMs
- PIP O-05-4245, Failure of the 3D2 HDP Discharge Flow Control Valve Resulted in Unit 3 Reducing Power to 87 Percent RTP

b. Findings

No findings of significance were identified.

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 the response was appropriate to the event. As appropriate, 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 response 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-05-2735, Air Leak on 3PR-20 Results in TS Limiting Condition for Operation (LCO) 3.0.3 Entry
- PIP O-05-3599, KHU Main Transformer Cooling Fan Primary Power Supply Contractor cannot Function

b. Findings

No findings of significance were identified.

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 TS LCOs. The inspectors reviewed the following six operability evaluations:

- PIP O-05-2364, While Performing 'As-found' Valve Strokes on 1 Main Steam (MS) -161 and 163, Valves Would Not Open
- PIP O-05-3200, Reactor Building (RB) Overpressure of 2.2 psi is Not Assured at All Points of Time Following a Large Hot Leg Break LOCA
- PIP O-05-3587, KHU-1 Exciter Warning Alarm
- PIP O-05-3599, KHU Main Transformer Cooling Fan Primary Power Supply Contractor cannot Function
- PIP O-05-3670, SSF Diesel Generator Tripped on Overcurrent

- PIP O-05-4342, KHU-1 Failed to Start While Performing an Operability Verification

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

.1 Semi-Annual Review of the Cumulative Effects of Workarounds

a. Inspection Scope

The inspectors performed a cumulative review of existing operator work-arounds to determine any change from the previous review. The review also considered the effect of the work-arounds on the operators ability to implement abnormal or emergency operating procedures. The inspectors periodically reviewed PIPs and held discussions with operators to determine if any conditions existed that should have been identified by the licensee as operator work-arounds.

b. Findings

No findings of significance were identified.

.2 Risk Significant Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed one significant operator work-around 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 workarounds 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.

- The work-around reviewed was documented in PIP O-05-3786, Unit 3 Concentrated Boric Acid Storage Tank temperature not being maintained above 125 degrees by the heat trace system. In order to maintain the temperature greater than 125 degrees, the control operators recirculated the tank for 4 to 6 hours every 3 to 4 days. Also mitigating this condition, a temporary low temperature computer alarm point has been established at 126 degrees.

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/1/A/0400/007, SSF RC Makeup Pump Test (Outage), following 18 month preventive maintenance activities
- PT/3/A/0600/013, 3A Motor Driven Emergency Feedwater Pump Test, following motor inspection and lubrication
- PT/1/A/0600/012, U1 TDEFDW Pump Test, following the recoupling of the turbine and pump during 1 EOC-22 RFO
- PT/0/A/0250/025, HPSW Pump and Fire Protection Flow Test, following realignment of the A HPSW Pump and motor
- PT/0/A/0711/001, Zero Power Physics Test, following 1 EOC-22 RFO
- PT/0/A/0811/001, Power Escalation Test, following 1 EOC-22 RFO

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors conducted reviews and observations for selected outage activities to ensure that: (1) the licensee considered risk in developing the outage plan; (2) the licensee adhered to the outage plan to control plant configuration based on risk; (3) that mitigation strategies were in place for losses of key safety functions; and (4) the licensee adhered to operating license and TS requirements. Between April 9, 2005, and May 17, 2005, the following activities related to the Unit 1 refueling outage were reviewed for conformance to applicable procedures and selected activities associated with each evaluation were witnessed:

- Outage risk management plan/assessment
- Clearance activities
- Reactor coolant system instrumentation
- Plant cooldown

- Mode changes from Mode 1 (power operation) to No Mode (defueled)
- Shutdown decay heat removal and inventory control
- Containment closure
- Mid-Loop activities
- Refueling activities
- Plant heatup/mode changes
- Core physics testing
- Power Escalation

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed surveillance tests and/or reviewed test data of the eight 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/0251/001, 3A Low Pressure Service Water Pump Test (Inservice Testing (IST))
- PT/2/A/0600/012, Unit 2 TDEFW Pump Test (IST)
- PT/1/A/0151/019, Penetration 19 Leak Rate Test (Containment Leak Rate)
- PT/1/A/0150/022M, 1FDW-315 and 1FDW-316 Stroke Test
- PT/1/A/0251/019, MS Atmospheric Dump Valve Functional Test
- IP/0/B/0125/003, Seismic Trigger Annual Calibration
- IP/1/B/0125/004, Strong Motion Accelerograph Functional Test
- IP/1/B/0125/004, Strong Motion Acceleration System Calibration

b. Findings

Introduction: A Green NRC-identified NCV of TS 5.4.1 was identified for failure to follow the procedure requirements in replacing the Seismic Trigger System batteries.

Description: While reviewing the work order for calibration of the seismic switch used to activate the seismic monitoring circuitry, the inspectors noted that the licensee had not followed the procedure requirements in that the seismic switch batteries had not been changed as required by procedure and no justification was provided in the completed procedure to explain why the procedure steps had not been followed. Procedure IP/B/0125/003, Seismic Trigger Calibration, Step 10.1.11 required the technician to replace the batteries if they were greater than three years old. The batteries were dated June 1999, and the annual calibration did not replace the batteries until April 2005. Based on the as found voltages, it appeared that the batteries had remained functional. The inspectors also noted the following deficiencies. The inspectors noted that the “Annual Calibration” was not being performed annually as specified by the procedure and recommended by the manufacturer's technical manual. The calibration was being performed on a refueling cycle (18 month) periodicity. The inspectors also noted that the calibration procedure was inadequate in that it did not provide adequate acceptance criteria for centering the masses associated with the motion detectors. The procedure required the technician to verify that the masses were "centered," while the technical manual required the masses to be "centered within .5 mm." The inspectors also noted that the procedure was deficient in that it did not require verification or documentation of the replacement battery voltages which should be performed to ensure that the new batteries met the minimum acceptable voltage requirements.

In addition, while observing the calibration and testing of the seismic monitoring recorder, the inspectors noted that the calibration and testing were being performed by the seismic monitoring manufacturer's technical representative using the manufacturer's test and calibration procedure. The inspectors concluded that this was an unapproved procedure and noted that it was not maintained as a Quality Assurance (QA) document and did not receive the appropriate site management approvals prior to use. The licensee technician was following the technical representative with Oconee's procedure, however, the manufacturer's procedure and Oconee's procedure did not contain the same steps.

These issues were discussed with the licensee and two PIPs were initiated. PIP O-05-04028 noted that the technicians had failed to follow procedure requirements in that the batteries had not been replaced as required which was a violation of site requirements contained in Nuclear Station Directive (NSD) 704, Procedure Use and Adherence, during the 2003 performance of IP/0/B/0125/003. PIP O-05-04144 noted that the Oconee calibration procedure did not agree with actual procedure performed by the vendor and Oconee's procedure did not agree with the vendor technical manual for centering of the seismic trigger masses.

<u>Analysis:</u> The inspectors determined that the failure to follow procedure in replacing the batteries as required, the inadequate procedure for centering the masses, and use of an unapproved procedure to perform the calibrations collectively represented a performance deficiency because the licensee is required to follow procedures, have procedures with adequate acceptance criteria and to use approved procedures. The finding was considered to be more than minor in that it was concluded by the inspectors that failure to follow the procedure requirements of replacing the batteries could render the seismic switch and therefore, the seismic monitors inoperable, if the batteries failed after their expiration dates. Thus if left uncorrected the finding would become a more significant safety concern because this equipment is used to determine whether or not the units need to be shutdown following a seismic event. In addition, it was concluded that the finding affected the reliability of systems that respond to initiating events in that it could affect the post event operating procedures (AOPs and EOPs) for responding to a seismic event. The finding was screened using the Phase 1 screening criteria specified under Seismic, Flooding and Severe Weather Screening Criteria. The inspectors concluded that whether or not the failure to replace the batteries represented a degradation of equipment, since the finding did not represent an actual loss of function, the issue would be screened as Green by Questions 2 and/or 3 of this section.

Enforcement: TS 5.4.1 requires that procedures shall be established, implemented and maintained covering the applicable procedures recommended in Regulatory Guide (RG) 1.33. RG 1.33, Section 6.w, requires procedures for combating emergencies and other significant events for acts of nature such as earthquakes. Section 8 requires appropriate procedures for the calibration of sensors and alarm devices. RG 1.33 endorses ANSI N18.7 in which section 5.2.2 requires that procedures be followed. Contrary to the TS 5.4.1 (ANSI N18.7) as implemented by NSD 704, on April 3, 2003, the licensee failed to follow procedure in replacing the seismic trigger system batteries after exceeding the specified age of the batteries. Because the finding was determined to be of very low safety significance and the various procedure deficiencies noted in the discussion section have been entered into the licensee's corrective action program as PIP O-05-04144 and PIP O-05-04028, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000269,270,287/2005003-01: Failure to Follow Procedure Requirements for Replacing the Seismic Trigger System Batteries.

1EP2 Alert and Notification System Testing

a. Inspection Scope

The inspectors evaluated the adequacy of licensee methods for testing the alert and notification system in accordance with NRC Inspection Procedure 71114, Attachment 02, "Alert and Notification System (ANS) Testing." The applicable planning standard 10 CFR Part 50.47(b)(5) and its related 10 CFR Part 50, Appendix E, Section IV.D requirements were used as reference criteria. The criteria contained in NUMARC/NESP-007, "Methodology for Development of Emergency Action Levels," Revision 2 and Regulatory Guide 1.101 were also used as references.

The inspectors reviewed documents which are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation

a. Inspection Scope

The inspectors reviewed the ERO augmentation staffing requirements and the process for notifying the ERO to ensure the readiness of key staff for responding to an event and timely facility activation. The results of the August 31, 2004, unannounced off-hours augmentation drill were reviewed. The inspectors conducted a review of the backup notification systems. The qualification records of key position ERO personnel were reviewed to ensure that ERO qualifications were current. A sample of problems identified from augmentation drills or system tests performed since the last inspection were reviewed to assess the effectiveness of corrective actions. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 03, "Emergency Response Organization (ERO) Augmentation Testing." The applicable planning standard, 10 CFR 50.47(b)(2) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

The inspectors reviewed documents which are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level (EAL) and Emergency Plan Changes

a. Inspection Scope

The inspectors evaluated the 10 CFR 50.54(q) reviews associated with non-administrative emergency plan changes, implementing procedures changes, and EAL changes. The revisions covered the period from January 2004 to May 2005.

The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 04, "Emergency Action Level and Emergency Plan Changes." The applicable planning standard, 10 CFR 50.47(b)(4) and its related 10 CFR 50, Appendix E requirements were used as reference criteria. The criteria contained in NUMARC/NESP-007, "Methodology for Development of Emergency Action Levels," Revision 2 and Regulatory Guide 1.101 were also used as references.

The inspectors reviewed documents which are listed in the Attachment to this report.

b. Findings

Introduction. A Severity Level IV NCV was identified for implementing a change which decreased the effectiveness of the Emergency Plan, contrary to the requirements of 10 CFR 50.54(q).

Description. During the May 2005 review of the licensee's Emergency Action Level and Emergency Plan changes, the inspectors held discussions with licensee staff and management regarding the change to Emergency Action Level 4.7.U.2.1 classification of "Natural Disasters, Hazards and Other Conditions Affecting Plan Safety." The inspectors noted that the EAL revision allowed the Keowee lake elevation to increase from 807 feet to 815.5 feet before an unusual event notification was made. This change reduced the effectiveness of the Oconee Nuclear Station emergency plan and impacted the regulatory process. The change extends the time period required for appropriate emergency classification of a natural disaster which could adversely affect the performance of both onsite and offsite emergency actions.

Prior to revision 17 the Emergency Action Level 4.7.U.2.1 wording was:

> "Reservoir elevation greater than or equal to 807 feet with all spillway gates open

and the lake elevation continues to rise.”

The revised Emergency Action Level 4.7.U.2.1 wording (Revision 17 to RP/0/B/1000/001, effective 02/02/2005) was:

> “Reservoir elevation greater than or equal to 815.5 feet with all spillway gates open and the lake elevation continues to rise.”

Lake elevation of 800.0 feet is considered “Full Pond.” The maximum height of the Keowee Hydro Dam, an earthen dam, is at elevation 815.0 feet. The revised elevation of 815.5 feet initiates an Unusual Event after lake water “overtops” or over-flows the earthen dam by six inches. The implementation of Emergency Action Level 4.7.U.2.1, Revision 17, reduced the effectiveness of the Oconee Nuclear Station emergency plan and impacted the regulatory process. The change extends the event time allowed prior to appropriate emergency classification of a natural disaster which could adversely affect the performance of both onsite and offsite emergency actions.

Analysis. The inspectors determined that the subject finding potentially impeded the NRC’s regulatory process and is therefore, in accordance with Section 2.2.e of Appendix B to NRC Manual Chapter 0609, evaluated using the guidance in Section IV of NUREG-1600, General Statement of Policy and Procedure for NRC Enforcement Actions (Enforcement Policy), rather than the Significance Determination Process (SDP). This finding is greater than minor because the change removed any reaction time the Nuclear Regulatory Commission had prior to the revision to a natural and destructive phenomena affecting the Keowee Hydro dam. The loss of regulatory reaction time could adversely affect the performance of both onsite and offsite emergency actions. The finding was determined to be a Severity Level IV violation according to Supplement VIII (Emergency Preparedness) of the Enforcement Policy because it involved licensee failure to meet an emergency planning requirement (namely, 10 CFR 50.54(q)) not directly related to assessment and notification.

Enforcement. 10 CFR 50.54(q) states, in part, "A licensee authorized to possess and operate a nuclear power reactor shall follow and maintain in effect emergency plans which meet the standards in Section 50.47(b) and the requirements in Appendix E of this part. The nuclear power reactor licensee may make changes to these plans without Commission approval only if the changes do not decrease the effectiveness of the plans and the plans, as changed, continue to meet the standards of 10 CFR 50.47(b) and the requirements of Appendix E to this part." The licensee’s implementation of changes to Emergency Action Level 4.7.U.2.1, Revision 17, decreased the effectiveness of the emergency plan without prior NRC approval, and was consequently a violation of 10 CFR 50.54(q). The finding is not suitable for SDP evaluation, but has been reviewed by NRC management and is determined to be a finding of very low safety significance. Because the violation has been entered into the licensee’s corrective action program as PIP O-05-03580, it is being treated as a non-cited Severity Level IV violation consistent with Section VI.A of the Enforcement Policy. NCV 05000269,270,287/2005003-02, Implementation of a Change to Emergency Action Level 4.7.U.2.1 which Decreased the Effectiveness of the Emergency Plan, Rev. 2005-01, February 2005.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope

The inspectors reviewed the corrective actions identified through the EP program to determine the significance of the issues and to determine if repeat problems were occurring. The facility's self-assessments and audits were reviewed to assess the licensee's ability to be self-critical, thus avoiding complacency and degradation of their EP program. In addition, inspectors review licensees' self-assessments and audits to assess the completeness and effectiveness of all EP-related corrective actions.

The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 05, "Correction of Emergency Preparedness Weaknesses and Deficiencies." The applicable planning standard, 10 CFR 50.47(b)(14) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

The inspectors reviewed documents which are listed in the Attachment to this report.

Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors reviewed the licensee's procedure for developing the data for the EP PIs which are: (1) Drill and Exercise Performance (DEP); (2) ERO Drill Participation; and (3) ANS Reliability. The inspectors examined data reported to the NRC for the period January 2004 to March 2005. Procedural guidance for reporting PI information and records used by the licensee to identify potential PI occurrences were also reviewed. The inspectors verified the accuracy of the PI for ERO drill and exercise performance through review of a sample of drill and event records. The inspectors reviewed selected training records to verify the accuracy of the PI for ERO drill participation for personnel assigned to key positions in the ERO. The inspectors verified the accuracy of the PI for alert and notification system reliability through review of a sample of the licensee's records of periodic system tests.

The inspection was conducted in accordance with NRC Inspection Procedure 71151, "Performance Indicator Verification." The applicable planning standard, 10 CFR 50.9

and NEI 99-02, Revision 3, "Regulatory Assessment Performance Indicator Guidelines," were used as reference criteria.

The inspectors reviewed documents which are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

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, 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 inspector 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 January 2005 through June 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 with their CAP. However, the inspectors noted that a large number of PIPs have been generated for dropped flags on relays associated with various plant equipment, specifically 50G, 50X, and 50Z relay targets. The observations were discussed with the licensee, and PIP O-05-4328 was generated for the emerging trend. PIP O-05-4328 documented that 11 previous PIPs had been written for dropped flags on 50 relays since March 2005, and that the relays had been reset without incident. The inspectors attempted to validate the licensee's assertion that only 11 PIPs have been generated for dropped 50 relays since March 2005. The inspectors discovered an additional 12 PIPs associated with dropped 50 relays. The inspectors discussed the 12 previously generated PIPs with the licensee, and the PIPs have been included in the emerging trend PIP. The licensee's investigation of this observation is ongoing.

.3 Focused Review

a. Inspection Scope

The inspectors performed an in-depth review of five issues entered into the licensee's corrective action program. The samples were 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.

b. Findings and Observations

(1) PIP O-02-5994, Engineering guidance for steam generator level control cabinet (SGLC) terminations

The problem addressed in this PIP, which was written in 2002, is that the installation procedures covering cable terminations did not provide specific instructions and methods for the installation of low-voltage, low-power, transient suppression devices having solid wire leads. The question arose in relation to modification NSM-23053, which modified the automatic feedwater isolation system (AFIS).

The inspectors examined the terminations at the AFIS/SGLC control cabinet in the cable room on the 809-foot elevation of the control complex at all three units. The inspectors observed that two types of terminal blocks were used: Style WTR 2.5/ZZ disconnect/test terminal blocks manufactured by Weidmüller Co. and standard type terminal blocks as manufactured by several companies. The Weidmüller terminal blocks have a tension clamp and clamping screw design wherein the wire to be terminated is inserted into the clamp and then tightening the screw clamps the wire and makes a good electrical connection. The Weidmüller terminal blocks were used in the modification because they are narrower than a standard terminal block and therefore allow more wires to be terminated for a given linear dimension of panel space. In addition, they provided a test switch and a point for connecting a test lead.

The inspectors observed that the Weidmüller terminal blocks in the AFIS/SGLC cabinet had a number of transient surge suppressors connected to them. These transient surge suppressors were style 1N6071A manufactured by Microsemi company. They weigh approximately 1.4 grams and have solid wire leads of diameter between 0.026 and 0.035 inches, which corresponds to American Wire Gauge (AWG) No. 22 and 20, respectively. The inspectors also checked the Weidmüller company engineering application data and saw that the WTR 2.5/ZZ terminal blocks are listed by Underwriters Laboratories to accept wires in the range of AWG No. 26 through 12 inclusive, which encompasses the wire sizes of the transient surge suppressors. Weidmüller recommends a torque of 5 lb-in be applied to the screw clamps of the WTR 2.5/ZZ terminal blocks, and the inspectors noted that this value was contained in Instrument Procedure IP/O/A/3009/017, Table 11.11.4 and in Enclosure 11.16, Weidmüller Terminal Block Screw Torque Documentation, which includes a Quality Control inspector sign-off.

The standard terminal blocks also had a number of transient surge suppressors connected to them. These transient surge suppressors consisted of 104MACQRL-150 capacitor/resistor package manufactured by Mallory Co. in series with a resistor manufactured by Ohmite Co. Both these devices had solid wire leads of AWG No. 19 or 20. Specifically at the Unit 2 AFIS/SGLC cabinet, one lead from the capacitor/resistor package and one lead from the resistor were butt-spliced with a sleeve crimp connector and remaining two leads were connected to the terminal block with a crimped ring tongue lug.

The inspectors concluded that the installation method of both styles of surge suppressor described above was acceptable. The 2002 version of IP/O/A/3009/017 addressed solid wire connections in that Enclosure 11.2, Bare Wire Size/Diameter Cross Reference, included single strand (i.e. solid wire) for sizes AWG No. 22 through 2. PIP O-02-5994 contained corrective actions to enhance or clarify Procedure IP/O/A/3009/017, Wire Terminal Installation, Labeling, and Termination, as well as Duke Power Specification DPS-1390.01-00-0003 having the same title, with regard to solid wire terminations and surge suppressors. The inspectors confirmed that these changes had been made.

The overall conclusion from review of this PIP was that the stated problem was adequately resolved.

(2) PIP O-02-5733, Power cable not installed per specification

This PIP, which was written in 2002, addressed several issues associated with two low-voltage power cables installed in October 2002. One issue involved whether the cables were supported at intervals exceeding that specified in the installation specification. A second issue was whether stainless steel tie wraps could be used to support cable. Another issue was whether the power cables were run together with control cables which are generally not recommended.

The two cables in question were 2EX91 and 2EX97. Both were 3-conductor, 500 MCM, low-voltage cable with an overall interlocked armor and PVC jacket. 2EX91 ran from load center 2X9 in the equipment room to motor control center 2XS5 in the turbine building. 2EX97 was the same type cable and ran from load center 2X9 to motor control center 2XS4 in the turbine building. The load center and motor control centers are on the same elevation, and the length of these cables is about 210 feet. The routing is basically in cable tray and the route also involves a wall sleeve and a segment where the cables run outside of the tray supported by a supplementary support. The "cable installation data" indicated that there would be a field designed transition point between cable trays in the equipment room.

The inspectors obtained the cable installation data sheet and the associated installation verification sign-off sheets for these two cables, and inspected the installed cables throughout their route. The inspectors observed that the cables followed the route given on the data sheets. In the equipment room the two cables ran side by side. One cable tray section contained both power and control cables, and the power and control cables were separated by metal barriers installed in the tray. These barriers met the intent of not allowing 600 V circuits to be in direct contact with 120 V control circuits. At the supplementary support point between trays mentioned above, the inspectors measured the distance along the cables to the next support on either side, and also measured the diameter of the cables. The distance to the next support was 83¼ inches on one side of the supplementary support and 77 inches on the other side. The diameter was 2.8 inches. The distance between supports was then compared to the support spacing specified in the installation specification. Oconee System Specification OSS-0218.00-00-019, Cable Wiring and Separation Criteria, Rev. 9, Section 5.3.5, specifies that a cable having a diameter of greater than 2 inches through 3 inches shall have an unsupported length not exceeding 78 inches. Since the unsupported length exceeded the specification value, the licensee evaluated the installation, and that evaluation concluded that the installation was acceptable as installed. The inspectors reviewed the evaluation and agreed it was acceptable. One reason for acceptability is that the specified maximum unsupported distance for armored cable also listed a cable weight per foot of 9.31 lbs or a total force on the cable of 60 lbs (9.31 x 6.5) at the support point. The actual force on the cable at the support point for the cables in question would be less than 60lbs because the cable weighed less than 9.31 lbs.

Another issue was whether tie wraps could be used to support the weight of cables at supplementary support points outside cable trays. This issue was covered by Oconee System Specification OSS-0218.00-00-0025, Specification for the Installation of Field Run Cable Support Systems. The only method defined in this specification for supporting a field run (outside the tray) cable would be a pipe clamp manufactured by Unistrut Co., which is compatible with the Unistrut steel channels used as support members. The support discussed in the previous paragraph used this type of support hardware. Use of other methods of cable support such as stainless steel tie wrap material, would therefore require engineering evaluation to be utilized. The inspectors observed that there were a few points along the length of cables 2EX91 and 2EX97 that used stainless steel tie wraps to support the weight of the cable. These tie wraps are manufactured by Panduit Co., and the manufacturer’s engineering application data indicates they are designed for cable support use and have tensile strength of 100 lbs. Use of these tie wraps to support cable weight as opposed to merely securing a cable inside a cable tray would require engineering evaluation on a case by case basis. The stainless steel tie wraps used to support cable weight at a few points along the run of 2EX91 and 2EX97 would support less than 60 lbs and, in most cases, two tie wraps were installed. However, the integrity of the cable support system during a postulated seismic event is not dependent on the stainless steel tie wraps. The inspectors concluded that the stainless steel tie wraps used on cables 2EX91 and 2EX97 were used in an acceptable manner.

The inspectors concluded that the licensee’s evaluation for the stated problem contained within the PIP adequately addressed the problem. No corrective actions were necessary.

(3) PIP O-04-6024, Cables not installed per installation specification

After two cables were installed in 2004, a QC inspector questioned whether the installation met the requirements of the installation specification. The two cables in question were 3ENI316B and 3ENI416B, which were separation code blue and orange, respectively. What prompted the question was the fact that the "cable installation data" stated that the cable could be routed exterior to the cable tray without specifying any particular tray. What this meant was that the cable to be installed could be attached with tie wraps to the exterior of a cable tray. The concept behind this method was the realization in the planning stage that there was no available tray of the appropriate separation code in the routing area and that it would be difficult to install a new tray system in an already densely packed space. The statement was intended by the designers to allow the cable to be affixed to the outside of say a tray containing nonsafety-related cables because the tray side rail would provide a barrier between the nonsafety-related cables and the cables having a separation code. An additional concern stated in the PIP was that the cable was attached to the tray with plastic tie wraps. The concern of the QC inspector was the structural integrity of this method of cable routing. Besides structural integrity, the PIP indicates that a cable separation problem was created by the installation of the new cables. The cable installation data sheet for this cable installation effectively specified that the cable would be field routed. This implied that the installers would have to refer to the separation criteria to ensure that the separation criteria would be maintained, and that quality control inspection would check the separation criteria.

The inspectors obtained the cable installation data sheet and the associated installation verification sign-off sheets for these two cables, and inspected the installed cables throughout their route. These cables ran from the control rod drive interface cabinet 1FC-3 to control rod drive trip breakers, both located in the Unit 3 cable room in the control complex. They were about 85 feet long and were 3-conductor, AWG No. 12, low-voltage cable with an overall interlocked armor and PVC jacket. The cables were affixed to the outside of cable trays for the entire route except at the ends where they left the tray and entered the respective cabinets. At cable tray support locations, the cables were installed between the vertical tray support steel channel and above the horizontal tray support channel. The cables were affixed to the outside of the tray with stainless steel cable tie wraps. The inspectors concluded that the method of routing these cables provided acceptable structural integrity for the following reasons. The tie wraps had a tensile strength of 100 lbs and were installed every two or three feet along the cable having a weight of approximately 0.3 lbs per foot. The function of the tie wraps was to prevent sagging of the cable that would result if the only support for the cable was the cable tray support cross arms which were spaced about eight to ten feet. The actual support for the cable was the seismically designed cable tray support system itself and not the tie wraps. The inspectors noted that the practice of routing cable on the outside of a tray rail was not unique to this modification, but was used in several locations in the plant. The inspectors did not observe any separation code violations along the route of cables 3ENI316B and 4ENI416B.

Among the corrective actions stated in the PIP, was revising the relevant installation specification to clarify requirements related to using tie wraps to support cables on the side of cable trays and to replace the plastic tie wraps with stainless steel tie wraps. The applicable specification was Oconee System Specification OSS-0218.00-00-0019, Cable and Wiring Separation Criteria. The inspectors noted that revision 9 of the specification made changes related to this PIP. Section 5.3.4.4, Cables Installed Outside of Cable Tray, was revised or added and fully describes the installation method used for the cable installation described above and provides the rationale for acceptability of the method. Section 5.3.4.2, Stainless Steel Cable Ties, was revised to prohibit the use of plastic tie wraps on safety-related cable unless the tie wrap is merely securing a cable inside a cable tray where all the weight of the cable is supported by the tray. The rationale behind this change is that manufactures do not make any claims as to the long-term tensile strength of plastic tie wraps, whereas the stainless steel tie wraps have a published tensile strength. Plastic tie wraps have been used to secure cables to the outside of cable trays. In the course of making inspections in the control complex and auxiliary building, the inspectors made it a point to look at cables affixed to the side of cable trays, but he did not notice any broken tie wraps. As stated above, the inspectors observed that the originally installed plastic tie wraps on the cables in question had been changed to stainless steel type.

The PIP also states that the cable separation problem noted by the writer of the PIP was reviewed and found not to be a true separation problem; however, the review identified another separation problem not previously identified that resulted in re-pulling cable 3ENI416B.

The inspector’s overall conclusion from review of this PIP was that the cables in question were correctly installed, and that specification revisions were made to provide a clear standard against which cables can be installed and inspected.

While inspecting the cable installation described above in the Unit 3 cable room, the inspectors identified a weld on the cable tray support system that appeared to be of questionable quality. The weld was made to "splice" an approximately 1.5 foot length of Unistrut P1001 to an existing P1001 vertical cable tray support member for the purpose of installing an additional tray on the bottom of a stack of trays. The weld was unrelated to the modification being inspected. The inspectors requested that the licensee assign a certified welding inspector or other qualified individual to inspect the weld, which the licensee did. When that individual was shown the weld by the inspector, he stated that the weld was of questionable quality and probably would not pass a quality control inspection. Subsequently, the NRC inspector and the licensee individual identified a number of questionable welds on the cable tray support system in the Unit 3 cable room. Later, PIP O-05-4215 was initiated to evaluate the integrity of the cable tray support system in light of the questionable welds. The basic design of the cable tray support system in the Unit 3 cable room utilizes Unistrut channels with all bolted connections; however, due to clearance considerations there are a number of randomly located instances where connections were welded.

(4) PIP O-04-2703, Terminal blocks not protected from environment

Introduction: A self-revealing, Green, NCV of 10 CFR 50.49 (Environmental Qualification) was identified for allowing the terminal block associated with valve 1HP-21 to deteriorate (rust) beyond its qualified tested condition; thereby, creating a situation where this containment isolation valve may not have been able to fulfill its design function to close in a harsh environment.

Background: A ground fault alarm on the 125 VDC system and subsequent trouble shooting led to discovery that water had leaked into a junction box in the Unit 1 east penetration room causing a ground fault at the terminal block inside the junction box. The PIP states that the water may have come from a roof leak and that the box was missing an armored cable sealing connector which, if installed like at other junction boxes in the room, would have prevented entry of dripping water. The PIP states that a connector was installed, the terminal block replaced due to corrosion and a preventive maintenance work orders generated to periodically check the condition of this and other junction boxes in the penetration rooms. Discovery of this problem also led to a review of the equipment qualification requirements for equipment in the east penetration room.

Focusing on the Unit 2 reactor coolant pump seal return valve (2HP-21), which is also located in its associated east penetration room, the inspectors reviewed the equipment qualification requirements. The inspectors examined JB-1178 and saw that the armored cables were sealed at the entry point with a connector and that the box itself was of a design that would tend to stop the ingress of dripping water. The terminal block was in good condition.

Valve HP-21 is a solenoid operated air powered valve. The evaluation for PIP O-04-2703 states that the valve HP-21 should be qualified for a main steam line break in the east penetration room. This valve is a containment isolation valve and its safety-related function is to close upon an engineered safeguards signal. The inspectors reviewed elementary diagram OEE-151-8, Rev. 13, for HP-21 and confirmed that the valve would fail open upon loss of voltage to the solenoid which means that the terminal block in JB-1178 must not short-circuit due to the post accident harsh environment. Calculation OSC-8104, ONS HELB in Penetration Rooms, Rev. 2, dated July 2004, re-calculated the environmental conditions in the east penetration room due to a postulated steam line break. Calculation OSC-8505, Rev.1, completed on June 2, 2005, but not yet checked, evaluated specific equipments in light of the results of the OSC-8104 calculation. OSC-8505 states that the highest peak temperature for all of the Oconee electrical penetration room areas is approximately 527°F with the longest duration at this elevated temperature being about 50 seconds. The temperature is predicted to drop below 100°F after about 20 - 30 minutes. The inspectors compared these values to the qualification test data for the terminal block. The terminal block in question is style ZWM-25012 manufactured by States Co. (Now AVO International). The manufacture's published data sheet states that this terminal block is qualified for the following service conditions: 41-year life at 131°F, 95 percent humidity, 2.2x10E8 rads and 10g maximum acceleration seismic level. Technical Evaluation CGD-3007.02-04-001, States Terminal Blocks, Test Switches and Accessories, states that the ZWM-25012 terminal blocks are also qualified for a peak temperature of 400°F for 3 hours and a total integrated dose of 3x10E7. The licensee tested the terminal blocks for 96 hours in a steam environment as documented in Report No. TR-028, Test Report on the Environmental Evaluation of Terminal Blocks. One can observe from this data that the peak temperature of 527°F exceeds the manufacturer's rated peak temperature of 400°F. The licensee considered this acceptable based on a letter from Babcox & Wilcox Co. to the B&W Owners Group Analysis Committee, dated August 13, 1985. The essence of this letter was that calculations had been performed showing that a terminal block inside a 0.25-inch thick junction box when subjected to an ambient temperature step change of 140 to 440°F reached 154°F at the 90 second point. The inspectors agreed that it was reasonable to extrapolate this calculation to reach a conclusion that the terminal block in question would not reach 400°F in 50 seconds when subjected to an ambient temperature step change of 140 - 527°F; therefore, the testing bounded the new temperature profile. The qualification of equipment in the east penetration room according to the requirements of 10 CFR 50.49 is under review by NRC Headquarters.

However, water leaking into the box during normal plant operation as occurred in the past on the Unit 1 junction box due to lack of cable entry seal, could affect the validity of the qualification since the test conditions started with a new terminal block. Therefore, the initiation of a periodic check on the condition of the terminal block was considered a prudent step to maintain qualification over the years of plant operation. The inspectors confirmed that the preventive maintenance work order had been approved for implementation. The inspectors also concluded that the degraded condition represented a violation of NRC requirements as discussed below.

Description: Terminal box TB-178 contains a terminal block and wiring for valve 1HP-21, and both the terminal box and valve are in the east penetration room. The Equipment Qualification Master List, Rev. 8, dated August 2004, states that this terminal block must be qualified for a post-accident harsh environment. In the east penetration room a harsh environment would result from a main steam line break which is a design basis accident. In, or about April 2004, while troubling shooting a ground fault on the 125 VDC system the licensee discovered that the terminal block inside TB-178 had become rusted due to the ingress of water due to a missing cable connector which should have been installed to seal the box. Documentation shows that the valve was still functional at that time. However, the fact that the terminal block was rusted has implications with regards to the capability of the valve to function in the harsh environment of a postulated main steam line break. The qualification of the terminal block to function in a harsh environment was based on testing which simulated the harsh environment. That testing was performed on a terminal block which was in good condition (i.e., not rusted). Therefore, there is no objective evidence demonstrating that a rusted terminal block could withstand a harsh environment. The design basis function of valve 1HP-21 is to close upon low reactor coolant system RCS pressure or high containment pressure as could occur following a steam line break. The control circuit for this solenoid controlled, air powered, valve is such that loss of power to the solenoid would result in the valve opening. Failure of the terminal block could result in short-circuiting the solenoid, resulting in the opening of the valve.

Analysis: Valve 1HP-21 is required to function post-accident pursuant to 10 CFR 50.49. The fact that the licensee allowed a terminal block in the circuitry for this valve to deteriorate (rust) and create a situation where the valve may not have fulfilled its design function in a harsh environment, represents a performance deficiency. The performance deficiency is more than minor because it is associated with a cornerstone attribute and it affects the associated cornerstone objective. In this case, the safety consequences of this situation is that the reactor safety cornerstone of barrier integrity has been affected. The finding is associated with the cornerstone attribute of containment isolation system reliability and availability. The cornerstone objective of providing a physical barrier (containment) to protect the public from radio nuclide release was affected. The finding was evaluated for safety significance using the Manual Chapter 0609, Appendix H, Containment Integrity Significance Determination Process. The finding is a Type B finding in that there is no direct impact on the likelihood of core damage, but it affects containment integrity. Then in accordance with Table 6.2, on the line for large dry containment, the finding has very low safety significance (Green) because the leak past containment would be into a closed system and there was a redundant valve to perform the isolation function which was not affected by the harsh environment. The RCP seal return line does not have the potential for an inter-system loss of coolant accident (LOCA).

Enforcement: 10 CFR 50.49(f) requires that each item of electric equipment important to safety must be qualified by one of four methods. Each of these methods involves simulation testing or actual experience. Contrary to this requirement, the licensee allowed a terminal block to degrade to the point that the relied on testing no longer encompassed the actual condition of the equipment. Because this issue was of very low safety significance, was placed and corrected under the corrective action program as PIP O-04- 2703, this violation is being treated as an NCV in accordance with Section VI.A.1 of the Enforcement Policy: NCV 05000269/2005003-03, Failure to Maintain Equipment Qualification of RCP Seal Return Line Containment Isolation Valve.

(5) <u>Evaluation of Corrective Actions for Failed Electrical Contactor Supplying One Train of Power to KHU Main Step-Up Transformer Cooling Systems</u>

<u>Introduction</u>: A Green self-revealing NCV was identified for inadequate corrective actions related to the timeliness of identification of a failed electrical contactor supplying one train of power to the KHU main step-up transformer cooling systems, resulting in a reduction in reliability of the KHU overhead power path.

<u>Description</u>: On May 19, 2005, the licensee determined that the operating contactor for one of two power supplies to the KHU main step-up transformer was inoperable while performing an inspection of the associated cabinet. The other redundant contactor was operable and the transformer had cooling power supplied from the auxiliary bus for KHU-2 which had been aligned to the underground path. A work request was written to replace/repair the contactor. On May 24, 2005, the licensee realized that with the power for the step-up transformer cooling being supplied through the good contactor by the underground unit's (KHU-2) auxiliaries, that a fault on that auxiliary bus could affect both the underground and overhead path emergency power capability. The licensee declared the overhead path inoperable until the KHU underground and overhead paths could be realigned (swapped). This eliminated the possibility of the single fault affecting both units. The licensee later determined that a piece of the broken contactor was found in the bottom of the cabinet by an operator on May 2, 2005; however, a PIP was not written as the operator incorrectly assumed it was related to a deficiency tag hanging in the cabinet. Not initiating a PIP at the time of discovery allowed a condition adverse to quality affecting safety-related equipment to go unevaluated for an additional two weeks and left the KHU overhead path in a state of reduced reliability.

<u>Analysis</u>: The finding was considered to be more than minor because it affected the mitigating system cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events in that the reliability of the KHU overhead emergency power path was reduced for approximately a three week period. However, the cooling power to the transformer was maintained during this period; therefore, there was no actual loss of safety function for either the underground or overhead emergency power path. Consequently the finding was determined to be of very low safety significance (green), as it was screened out by question 1 under mitigating systems in the SDP Phase 1 Screening Worksheet. This finding involved the cross-cutting aspect of problem identification and resolution (PI&R).

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 place into their corrective action program a deficiency observed in the KHU step-up transformer cooling power cabinet which in turn delayed the identification of a condition adverse to quality. Because the inadequate corrective action measures were of very low safety significance and have been entered into the licensee's corrective action program (PIP O-05-3599), this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. It will be identified as NCV 05000269,270,287/2005003-04:

Inadequate Corrective Actions Related to the Identification of a Failed KHU Main Step-up Transformer Cooling Power Contactor.

.4 Summary of PI&R Cross-Cutting Findings

A Green NCV involving the cross-cutting aspect of PI&R is documented in Section 4OA2.3. The failure to place a deficiency observed in the KHU step-up transformer cooling power cabinet into the corrective action program delayed the identification of a condition adverse to quality.

4OA3 Event Followup

.1 (Closed) Licensee Event Report (LER) 05000287/200402-00, Open Containment Penetration during Refueling Activities.

The inspectors reviewed the circumstances surrounding the inadvertent creation of a flow path from containment via an open, 3/4-inch feedwater system drain line during the Unit 3 core reload and the licensee's corrective actions. This violation was documented in IR 2004-05 as a green Licensee Identified Violation. This LER is closed.

.2 (Closed) LER 05000269/200402-(00 and 01), Main Steam Line Break Mitigation Design/Analysis Deficiency

The licensee submitted this LER on July 6, 2004, and Revision 1 on September 9, 2004 as a result of a design deficiency where during certain small steam line breaks inside containment, in combination with a loss of offsite power (LOOP) could result in excessive reactor building pressures. The automatic feedwater isolation system (AFIS) closes the main and startup feedwater control valves which are air operated valves upon the sensing main steam line break conditions. For certain small breaks inside containment, the plant conditions that would trigger isolation may not occur prior to instrument air being lost if a LOOP occur. Therefore the break would not be isolated and the potential to over-pressure the reactor building. This condition was determined to be of very low safety significance as there was no actual loss of mitigation equipment or degradation of the reactor building barrier capability.

The inspectors reviewed the licensee's compensatory actions which were to declare AFIS inoperable until a diesel powered backup air supply to instrument air was installed. A total of three portable diesel air compressors were tied in to the service air header and provided with an autostart capability to maintain instrument air header pressure in the event of a LOOP. The inspectors determined that the licensee's compensatory measures were appropriate and noted that the long term corrective actions are to install motor operated feedwater isolation valves. This LER is closed.

.3 (Closed) LER 05000269/200403-00, Loss of Containment Spray due to Test When Redundant Train Inoperable.

On September 11, 2004, while performing a surveillance on System Channel 7 of the Engineered Safeguards Actuation System, a problem with a logic module power supply was discovered, and the channel was declared inoperable, including the 1A reactor building spray (RBS) train. The correct TS LCO Action Statements were then entered. At 3:15 p.m. on September 12, 2004, the 1B RBS train was declared OOS to stroke test 1LP-22, a pump suction valve. At 3:18 p.m. on September 12, 2004, the stroke test of 1LP-22 was complete and the 1B RBS train was returned to service. At that time, a control room operator recognized the problem and TS LCO 3.0.3 was entered. Additionally, computer data indicates that 1LP-22 was not fully open for 80 seconds, and that the valve indicated fully closed for 30 seconds. Consequently, the unit was operating in Mode 1 for less than three minutes with both trains of RBS inoperable but functional. The issue is minor because of the short duration of the inoperability and the fact that the 1A RBS train could have initiated manually if needed. The licensee entered this issue into their corrective action program as PIP O-04-5938. This LER is closed.

4OA5 Other Activities

.1 (Closed) NRC TI 2515/163, Operational Readiness of Offsite Power (OSP)

During this report period, inspectors collected data from licensee maintenance records, event reports, corrective action documents and procedures, and through interviews of station engineering, maintenance, and operations staff, as required by TI 2515/163. Appropriate documentation of the results was provided to headquarters staff for further analysis, as required by the TI. This completes the Region II inspection requirements in this TI for the Oconee Nuclear Station.

.2 (Closed) Unresolved Item (URI) 05000269/2004003-01, Inadequate Unit 1 Reactor Coolant Pump Seal Modification

a. Inspection Scope:

The inspectors completed the review of the licensee’s activities and obtained the results of the regional senior risk analyst’s risk determination of URI 0500269/2004003-01, Inadequate Unit 1 Reactor Coolant Pump Seal Modification.

b. Findings

Introduction: A Green self-revealing finding was identified for an inadequate design change when the licensee replaced the Unit 1 reactor coolant pump Westinghouse seals with Sultzer seals during the 2000 fall outage (RFO 19). This caused increased seal leakage past shaft to sleeve o-rings out of the Number 3 seal on all four reactor coolant pumps during operating cycle 20. Several of the design deficiencies were identified and corrected during RFO 20; however, corrective actions were not effective in identifying all of the seal package deficiencies and leakage continued during operating cycle 21. The leakage was such that upon a loss of normal RCP seal injection/cooling, the RCP seals could heatup to a point of failure. Seal face leakage was also observed due to particulate damage and continued through cycle 22; however, this leakage mechanism was assumed to be bounded by the o-ring leakage as the seal faces are more resistant to high temperatures.

<u>Description</u>: The licensee replaced Unit 1 Westinghouse RCP seals with Sulzer three stage balanced stator seals during U1 RFO 19. The reason for the replacement was that the Westinghouse seals were leaking up to 4.3 gpm out of the seal return due to particulate damage to the Number 1 seal at the double delta channel seal. Following the Unit 1 RCP seal modification during RFO 19, the following Number 3 seal leakages were observed during Unit1 Cycle 20: 1A1, 0.54 gpm; 1A2, 0.36 gpm; 1B1, 0.5 gpm; 1B2, 0.64 gpm. Leakage across the Number 3 seal is not isolated by controlled bleed-off (CBO) isloation, which potentially negates the CBO isolation function. CBO is isolated during a loss of seal cooling event to terminate the flow of hot RCS fluid across the seals that would leak up past the RCP thermal barrier. Therefore, even though the Sulzer seal leakage was less than the Westinghouse, the effect of the Sulzer leakage was to heat up the seal packages until seal injection could be initiated. Corrective action document PIP O-01-1619 documented that the new seal design specified an enlargement of the Number 3 seal ring groove in the seal sleeve to facilitate installation. This however reduced the o-ring squeeze from 18 percent to 7 percent which was below the vendor recommended minimum value of 16 percent. Also, the shaft to sleeve o-ring was too large for the non-standard shaft diameter of the Westinghouse shafts. This contributed to the poor o-ring seal. It was also determined that an additional centering ring was needed in the Number 3 seal to reduce seal “wobble” that was believed to contribute to the leakage. These deficiencies were corrected during RFO 20.

During Cycle 21, the Number 3 seal on three of the RCPs again experienced leakage measured to be: 1A1, 0.58 gpm; 1B1, 0.74 gpm; 1B2, 0.51gpm (an additional 0.4 gpm was estimated to be leaking out of the 1A1 and 1B1 seal housings). Subsequently, additional deficiencies were noted with the seal design. More heat is generated due to friction between the seal faces than the Unit 2 and 3 seals which results in a higher seal sleeve to pump shaft delta T (approximately 30 F). This results in higher thermal growth of the sleeve relative to the shaft (both materials had essentially the same thermal expansion coefficient). The installation of the sleeves to the shaft were tightened down such that there was no gap at the bottom of the Number 1 sleeve to the shaft base to allow thermal expansion. This caused a buckling/warping of the Number 3 sleeve that opened up the shaft to sleeve o-ring clearances. This problem was corrected during RFO 21 by providing for a 1/16 inch gap at the bottom of the sleeve to the shaft base and by also changing the sleeve material to one with a lower thermal expansion coefficient than the shaft. During online Cycle 21, o-ring leakage was eliminated; however, seal face leakage continued at approximately 0.5 gpm across the 1A1 and 1B1 seals. The licensee believes this is due to fine particulate damage to the seal faces; however, they are waiting on microscopic lab analysis to confirm this problem.

<u>Analysis</u>: The finding was considered to be more than minor because it affected the initiating events cornerstone, in that the Number 3 seal leakage affected the cornerstone objective to limit the likelihood of those events (specifically a seal LOCA) that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using Phase 1 of the Significance Determination Process the question under the initiating events cornerstone for primary system LOCA initiators was answered <u>yes</u>, as it was assumed that worst case degradation of the seals would exceed the TS limit for RCS leakage; therefore, a Phase 2 analysis was required. For the Phase 2

analysis, scenarios that result in loss of all seal cooling were considered and a seal LOCA assumed with no recovery credit. The Phase 2 analysis exceeded the threshold that required evaluation under Phase 3 of the SDP. A regional SRA performed a Phase 3 evaluation. The dominant accident sequences involved a high energy line break in the turbine building that fails all the safety related 4160 VAC buses, thus requiring the Safe Shutdown Facility (SSF) to be placed into service. Consequently, the Reactor Coolant Makeup Pump function fails and an Reactor Coolant Pump (RCP) Seal loss of coolant ensues. Insufficient RCS makeup capacity exists and the core uncovers. The critical assumptions used in the analysis were (1)The failure to close the RCP controlled bleed off valve (CBO) was used as the surrogate for the increased RCP seal leakage; (2) Only one pre-existing RCP seal failure will be considered since a plant shutdown should be executed due to the one seal failure: and (3) Consistent with industry topical reports on this pump type, the probability of a RCP seal loss of coolant is 1E-3 when the CBO is not isolated. Due to the nature of the performance deficiency, external initiators that require SSF operation to preclude core damage were also considered in this analysis. Based on the Phase 3 analysis, the finding was determined to be of very low safety significance (Green).

Enforcement: This finding was not a violation of regulatory requirements because the RCP seals are not considered to be safety- related, and therefore not under the requirements of 10 CFR 50, Appendix B. This finding is identified as FIN 05000269/2005003-05, Inadequate Unit 1 Reactor Coolant Pump Seal Modification. This issue is in the licensee's corrective action program under PIPs O-01-1619 and O-02-3830.

.3 (Closed) TI 2515/160, Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) (Unit 1)

The inspectors reviewed the licensee's 60-day response to NRC Bulletin 2004-01, dated July 27, 2004. The inspectors verified that the licensee's inspection activities conducted during this outage were consistent with their response.

The inspectors conducted an independent walk-down of the pressurizer to ensure that the physical conditions of the pressurizer penetrations and welds were clean and accessible for the prescribed inspections, and that there were no problems with debris, insulation, dirt, boron from other sources, physical layout, or viewing obstructions, which could have interfered with the identification of relevant indications. Specifically, the inspectors reviewed documentation for the following components:

- 1-PZR-WP91-1, 2.5" Nozzle to stainless steel Pressurizer Relief Valve Flange, ASME Class 1
- 1-PZR-WP91-2, 2.5" Nozzle to stainless steel Pressurizer Relief Valve Flange, ASME Class 1
- 1-PZR-WP91-3, 2.5" Nozzle to stainless steel Pressurizer Relief Valve Flange, ASME Class 1
- 1-PZR-WP-63-7, Between Nozzle and Safe End on 1" Sampling Line, ASME Class 1

- C 1-PZR-WP63-1 through 1-PZR-WP63-6, Pressurizer Nozzle to Safe End welds for 1" Level Instrument Taps, ASME Class 1
- C 1-RC-RD-0043, 1.5" Thermoweld Annulus area, ASME Class 1
- C 1-50-5-1, 1" Vent, ASME Class 1
- C 1PSP-1, 4" Spray Nozzle Safe End to Stainless Steel Piping, ASME Class 1
- C 1-PZR-WP-45, Safe End to 4" Pressurizer Spray Nozzle, ASME Class 1

Reporting Requirements are as follows:

a. For each of the examination methods used during the outage, was the examination:

1. Performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

   Yes. The licensee used knowledgeable staff members certified as Level II, VT-2 examiners in accordance with procedure NDE-B, "Training, Qualification, and Certification of NDE Personnel" to conduct a direct visual examination of the bare metal surface of the above components. This qualification and certification procedure referenced the industry standard ANSI/ASNT CP-189, "Standard for Qualification and Certification of Nondestructive Testing Personnel."

2. Performed in accordance with demonstrated procedures?

   Yes. The licensee conducted the bare metal inspection of the pressurizer penetrations in accordance with procedure QAL-15, "Inservice Inspection (ISI) Visual Examination, VT-2, Pressure Test." The licensee considered this procedure to be demonstrated because examination personnel could resolve specific size of lower case alpha numeric characters at the actual visual examination distance.

3. Able to identify, disposition, and resolve deficiencies?

   Yes. The inspectors concluded that the licensee's direct visual examinations were capable of detecting leakage from cracking in pressurizer penetrations if it had existed. This conclusion was based upon the inspectors direct observations of pressurizer penetration locations, which were free of debris or deposits that could mask evidence of leakage in the areas examined. The inspectors also verified that the licensee's procedures included guidance for proper disposition and investigation of any identified deficiencies.

4. Capable of identifying the leakage in pressurizer penetration nozzle or steam space piping components, as discussed in NRC Bulletin 2004-01?

   The inspectors verified that the licensee's examination personnel were capable of identifying any leakage in pressurizer penetration nozzles or steam space piping components.

b. What was the physical condition of the penetration nozzle and steam space piping components in the pressurizer system (e.g., debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

Through discussions with licensee personnel, the inspectors verified that the metal reflective insulation had been removed with extreme caution so as not to disrupt any potential indications of boric acid leakage from the pressurizer at these penetration locations. The licensee personnel performed a direct visual inspection of these pressurizer penetrations. The area examined was clean and free of debris or deposits or other obstructions which could mask evidence of leakage.

c. How was the visual inspection conducted (e.g., with video camera or direct visual by the examination personnel)?

The licensee's inspection personnel used the direct visual examination technique along with a handheld mirror.

d. How complete was the coverage (e.g., 360° around the circumference of all the nozzles)?

The licensee was able to view the entire circumference, 360°, around each penetration.

e. Could small boron deposits, as described in the Bulletin 2004-01, be identified and characterized?

The examination personnel were appropriately trained and qualified to identify small boron deposits as described in the bulletin.

f. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

There were no deficiencies identified that required repair.

g. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

There were no impediments for an effective examination.

h. If volumetric or surface examination techniques were used for the augmented inspections examinations, what process did the licensee use to evaluate and dispose any indications that may have been detected as a result of the examinations?

Not Applicable. No augmented surface or volumetric examinations were performed. In accordance with the licensee's response, only a BMV examination was conducted this outage, and there were no indications identified that required further examination.

l. Did the licensee perform appropriate follow-up examinations for indications of boric acid leaks from pressure-retaining components in the pressurizer system?

Not Applicable. There were no indications of boric acid leaks from pressure-retaining components in the pressurizer system.

.4 (Closed) URI 50-269,270,287/2004004-04, Acquisition and Review of QA Data Packages for Effluent Monitor Calibrations

During an NRC inspection in September 2004, the licensee was unable to provide documentation which verified the traceability and accuracy of the sources used for effluent monitor calibrations. Selected Licensee Commitment (SLC) Radioactive Effluent Monitoring Instrumentation Surveillance Requirement 16.11.3.9 requires, in part, that the initial channel calibration be performed using standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with the National Institute of Standards and Technology. For subsequent channel calibration, sources that have been related to the initial calibration shall be used. To ensure that channel calibrations were being properly performed, the inspectors requested documentation to demonstrate that effluent monitor calibrations were accurate and traceable to national measurement standards as discussed in SLC 16.11.3.9.

The licensee obtained, from the effluent monitor vendor, certificates for specific field transfer calibration sources and documentation of factory calibrations of monitor detectors using those sources. The documentation package included source certificates, traceable to NBS, for nine transfer sources and the associated detector calibrations for 38 effluent monitors. The documentation package also provided evidence that the initial channel calibrations were performed using an NBS traceable calibration range and verified prior to shipment. An in-office review of the documentation package by the inspectors determined that the licensee is meeting the requirements of SLC 16.11.3.9 with respect to the traceability and accuracy of the transfer sources used to perform calibrations on the effluent monitors. The transfer sources for which the traceability and relation to the initial calibration were verified included Oconee Nuclear Station Instrument (ONSI) source numbers: 238, 296, 297, 298, 307, 308, 309, 374, and 393.

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 July 6, 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 Annual Assessment Meeting Summary

On April 27, 2005, the NRC's Region II Regional Administrator, Chief of Reactor Projects Branch 1 and the Oconee Resident Inspectors met with Duke Energy to discuss the NRC's Reactor Oversight Process and the Oconee Nuclear Station annual assessment of safety performance for the period of January 1, 2004 - December 31, 2004. The major topics addressed were the NRC's assessment program and the results of the Oconee assessment. Attendees included Oconee site management, members of site staff, and local news media.

This meeting was open to the public. The presentation material used for the discussion is available from the NRC's document system (ADAMS) as accession number ML051990361. 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

N. Alchaar, Civil Engineering
L. Azzarello, Modification Engineering Manager
S. Batson, Superintendent of Operations
D. Baxter, Engineering Manager
R. Brown, Emergency Preparedness Manager
J. Bryan, Reactor & Electrical Systems
T. Bryant, Engineering Support
A. Burns, Civil Engineer, Reactor & Electrical Systems
S. Capps, Mechanical/Civil Engineering Manager
G. Chronister, Modifications Engineering
T. Coleman, ISI Coordinator
N. Constance, Operations Training Manager
D. Covar, Training Instructor
C. Curry, Maintenance Manager
G. Davenport, Compliance Manager
K. Davis, ECT Level III
P. Downing, SGME Manager
C. Eflin, Requalification Supervisor
P. Fowler, Access Services Manager, Duke Power
T. Gillespie, Reactor and Electrical Systems Manager
T. Grant, Engineering Supervisor, Reactor & Electrical Systems
R. Griffith, QA Manager
B. Hamilton, Station Manager
R. Hester, Civil Engineer
D. Hubbard, Training Manager
R. Jones, Site Vice President
T. King, Security Manager
T. Ledford, Engineering Supervisor, Reactor & Electrical Systems
L. Llibre, Engineering Supervisor
R. Murphy, Engineering Support
S. Neuman, Regulatory Compliance Group
L. Nicholson, Safety Assurance Manager
J. Rowell, Engineer, Reactor & Electrical Systems
W. Simmons, Electrical Maintenance
J. Smith, Regulatory Affairs
B. Spear, Engineer, Reactor & Electrical Systems
J. Steeley, Training Supervisor
J. Stinson, Engineer, Reactor & Electrical Systems
P. Stovall, SRG Manager
F. Suchar, QC Supervisor
D. Taylor, Refurbishment Group
R. Taylor, Emergency Preparedness
S. Townsend, Keowee Operations

J. Twiggs, Manager, Radiation Protection
R. Waterman, Emergency Preparedness
J. Weast, Regulatory Compliance
E. Welsch, Reactor & Electrical Systems Engineering

NRC

M. Ernstes, Chief of Reactor Projects Branch 1
W. Travers, Regional Administrator, RII

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000269,270,287/2005003-01	NCV	Failure to Follow Procedure Requirements for Replacing the Seismic Trigger System Batteries (Section 1R22)
05000269,270,287/2005003-02	NCV	Implementation of a Change to Emergency Action Level 4.7.U.2.1 which Decreased the Effectiveness of the Emergency Plan (Section 1EP4)
050000270/2005003-03	NCV	Failure to Maintain Equipment Qualification of RCP Seal Return Line Containment Isolation Valve. (4OA2.3b.(4))
05000269,270,287/2005003-04	NCV	Inadequate corrective actions related to the identification of a failed KHU main step-up transformer cooling power contactor (Section 4OA2.3b.(5))
05000269/2005003-05	FIN	Inadequate Unit 1 Reactor Coolant Pump Seal Modification (Section 4OA5.2)

Closed

05000269/2004003-01	URI	Inadequate Unit 1 Reactor Coolant Pump Seal Modification (Section 4OA5.2)
50000269,270,287/2004004-04	URI	Acquisition and Review of QA Data Packages for Effluent Monitor Calibrations (Section 4OA5.4)

05000287/200402-00	LER	Open Containment Penetration during Refueling Activities (Section 4OA3.1)
05000269/200402-(00 and 01)	LER	Main Steam Line Break Mitigation Design/Analysis Deficiency (Section 4OA3.2)
05000269/200403-00	LER	Loss of Containment Spray due to Test When Redundant Train Inoperable (Section 4OA3.3)
2515/163	TI	Operational Readiness of Offsite Power (Section 4OA5.1)
2515/160	TI	Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) (Unit 1) (Section 4OA5.3)

DOCUMENTS REVIEWED

Sections 1R08 & 4OA5.3: Inservice Inspection Activities

Nondestructive Examination
NDE-35, Liquid Penetrant Examination, Rev. 20
NDE 12, General Radiography Procedure For Preservice and Inservice Inspection, Rev. 11
ESD Boric Acid Corrosion Control Program, Rev. 1
NSD 413, Fluid Leak Management Program, Rev. 3
WPS GTSM0808-01, GTAW and SMAW Welding Procedure
QAL-15, Inservice Inspection (ISI) Visual Examination, VT-2, Pressure Test, Rev. 20
NDE-600, Ultrasonic Examination of Similar Metal Welds in Ferritic and Austenitic Piping, Rev. 15

Steam Generator
Oconee Nuclear Station - Unit 1 Replacement Eddy Current Examination Plan
Oconee Site Specific Unit 1 EOC 22 Specific Replacement Once-Through Steam Generators (ROTSG) Assessment of Potential Degradation Mechanisms, Revision 5
Eddy Current Acquisition Guidelines for Duke Power Company’s ROTSG, Revision 0
Procedure 54-ISI-400-13, "Multi-Frequency Eddy Current Examination of Tubing, Revision 0
Procedure 54-ISI-24-29, "Written Practice for Personnel Qualification in Eddy Current Examination"
Eddy Current Analysis Guidelines for Duke Power Company’s ROTSG, Revision 0
Problem Identification Process (PIP) # O-05-2678 "Unexpected tube wear identification in ‘A’ and ‘B’ Steam Generators"
Problem Identification Process (PIP) # O-05-2532 "Lost several days running ECT in ‘A’ Steam Generator die to high temperature."
Field Procedure and Operating Instructions for Installation of a Flexible Stabilizer in a Recirculating Steam Generator, Rev. 17

<u>Corrective Action Documents (Problem Investigation Process [PIP])</u>
O-05-02810, Boron Observed in between body to bonnet flange connection of 1HP-194
O-03-06537, OE From Crystal River on Pressurizer Penetration Leak
O-01-03497, Design Configuration Control Issues related to Flow Accelerated Corrosion
O-05-02234, Problems with Relief Requests Submitted Per 10 CFR 50.55(a)
O-05-02347, Active Leak from 1RC-206 with Pressurizer Sample Line in Service
O-05-02320, Unit 1 Reactor Building Engineering Walk-down results
O-05-02315, Unit 1 Boric Acid Corrosion Control Walk-down results

Section 1EP2: Alert and Notification System Testing

<u>Records and Data</u>
Alert and Notification System test data (1/04-3/05)
Section 3.3, Alert and Notification System (Siren Program), Emergency Planning Functional Area Manual, Rev. 5
Section 3.6, Alert and Notification System - Oconee Specific Supplement, Rev. 3

Section 1EP3: Emergency Response Organization (ERO) Augmentation

<u>Procedures</u>
GO-04-14(NPA)(EP)(ALL), 2004 Emergency Planning Assessment
ERTG-001, Emergency Response Organization and Emergency services training program, Rev. 13

<u>Records and Data</u>
Attachment 3.2.5.1, Duke Power Emergency Planning Business Measures, Emergency Planning Functional Area Manual, 1st Quarter 2005
Plan Number: 04EP2P3, Emergency Planning Corrective Action Assessment
Emergency Response Organization Training Data

Section 1EP4: Emergency Action Level (EAL) and Emergency Plan Changes

<u>Procedures</u>
Emergency Plan, Rev. 2004-01, February 2004
Emergency Plan, Rev. 2004-02, December 2004
Emergency Plan, Rev. 2005-01, February 2005
RP/0/B/1000/024, Protective Action Recommendations, Rev. 4
RPSM 11.3 - Offsite Dose Assessment and Data Evaluation, Rev.001
RP/0/B/1000/007, Security Event, Rev. 007
NEI 99-01, Methodology for Development of Emergency Action Levels, Rev. 4

<u>Records and Data</u>
10 CFR 50.54(q) Evaluation 2005-001
10 CFR 50.54(q) Evaluation 2004-001
10 CFR 50.54(q) Evaluation 2004-002
10 CFR 50.54(q) Evaluation RP/0/B/1000/001, Rev. 17

Section 3.1, Administration of the Emergency Plan and Emergency Plan Implementing Procedures, Emergency Planning Functional Area Manual, Rev. 6

Section 1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

Records and Data
Nuclear System Directive 208, Problem Investigation Process (PIP), Rev. 13
2004 Business Measures
2005 Business Measures
Group Trends - Overall PIP evaluation per EP trend code 2004, 1st QTR 2005
04EP2P3, EP Corrective Actions Assessment, 5/10/04

Problem Investigation Process (PIPs)
O-04-07317
O-04-06494
O-04-06501
O-04-07110
O-05-02027
O-05-01460
O-05-03574
O-05-03580

Section 4OA1: Performance Indicator (PI) Verification

Records and Data
Section 3.7, NRC Regulatory Assessment Performance Indicator Guideline - Emergency Preparedness Cornerstone, Emergency Planning Functional Area Manual, Rev. 7
Data packages for 01/2004-03/2005 for ERO participation
Data packages for 01/2004-03/2005 for Drill/Exercise Performance
Data packages for 01/2004-03/2005 for Alert and Notification system

Section 4OA2: Identification and Resolution of Problems
Procedure IP/O/A/3009/017, Wire Terminal Installation, Labeling, and Termination, Rev. 21
Specification DPS-1390.01-00-003, Wire Terminal Installation, Labeling, and Termination, Rev.5
Calculation OSC-8505, HELB EQ Analysis for Penetration Rooms, Rev. 1
Dwg. No. OLT-2780-03.01-12, Environmental Qualification Master List (Portions)
Technical Evaluation CGD-3007.02-04-001, States Terminal Blocks, Test Switches and Accessories, Rev.14
Test Report TR-028, Test Report on the Environmental Qualification of Terminal Blocks for McGuire, dated April 1981
Specification OSS-0218.00-00-0019, Cable and Wiring Separation Criteria, Rev. 9
Specification OSS-0218.00-00-0025, Specification for the Installation of Field Run Cable Support Systems, Rev. 9
PIP O-05-1746 and PIP O-04-8170, 3SF-82 and 3SF-405 conductor failures
PIP O-05-3599, KHU Main Step-up Transformer Cooling Power Contactor Failure

LIST OF ACRONYMS

ADAMS	-	Agency wide Documents Access and Management System
AFIS	-	Automatic Feedwater Isolation System
ANSI	-	American National Standards Institute
ARM	-	Area Radiation Monitor
AP	-	Abnormal Procedure
ASME	-	American Society of Mechanical Engineers
CAP	-	Corrective Action Program
CBO	-	Controlled Bleed-Off
CCW	-	Condenser Circulating Water
CFR	-	Code of Federal Regulations
CRD	-	Control Rod Drive
DEC	-	Duke Energy Corporation
DG	-	Diesel Generator
EAL	-	Emergency Action Level
ECCS	-	Emergency Core Cooling
EHC	-	Electro-Hydraulic Control
EOC	-	End-of-Cycle
EOF	-	Emergency Operations Facility
EP	-	Emergency Plan
ERO	-	Emergency Response Organization
FDW	-	Feedwater
GPM	-	Gallons per Minute
HPSW	-	High Pressure Service Water
IP	-	Inspection Procedure
IR	-	Inspection Report
IST	-	Inservice Testing
KHU	-	Keowee Hydroelectric Unit
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accident
LOOP	-	Loss of Offsite Power
LPSW	-	Low Pressure Service Water
MS	-	Main Steam
NCV	-	Non-Cited Violation
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
NSD	-	Nuclear Station Directive
ONS	-	Oconee Nuclear Station
OOS	-	Out of Service
OSC	-	Operations Support Center
OSP	-	Offsite Power
PARS	-	Publicly Available Records
PIP	-	Problem Investigation Process report
PI&R	-	Problem Identification and Resolution
PM	-	Preventive Maintenance

PMT	-	Post-Maintenance Testing
PT	-	Performance Test
QA	-	Quality Assurance
QC	-	Quality Control
RAI	-	Request for Additional Information
RB	-	Reactor Building
RBES	-	Reactor Building Emergency Sump
RBS	-	Reactor Building Spray
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RFO	-	Refueling Outage
RG	-	Regulatory Guide
RII	-	Region II
RSPS	-	Risk Significant Planning Standard
RTP	-	Rated Thermal Power
RVH	-	Reactor Vessel Head
SDP	-	Significance Determination Process
SSC	-	Structure, System and Component
SSF	-	Standby Shutdown Facility
TDEFW	-	Turbine Driven Emergency Feedwater
TS	-	Technical Specification
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item