UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

July 28, 2003

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

SUBJECT: OCONEE NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000269/2003003, 05000270/2003003, AND 05000287/2003003

Dear Mr. Jones:

On June 28, 2003, the NRC completed an inspection at your Oconee Nuclear Station. The enclosed report documents the inspection findings which were discussed on July 1, 2003, with you 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, there were four NRC-identified findings of very low safety significance (Green). These findings were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as a non-cited violations (NCVs), in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, one licensee-identified NCV is listed in Section 4OA7 of this report. If you contest any of the NCVs 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, DC 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Oconee facility.

In accordance with 10 CFR 2.790 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/

Robert Haag, 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 05000269/2003003, 05000270/2003003, and 05000287/2003003 w/Attachment - Supplemental Information

cc w\encl.:
L. E. Nicholson
Compliance Manager (ONS)
Duke Energy Corporation
Electronic Mail Distribution

Lisa Vaughn
Legal Department (ECIIX)
Duke Energy Corporation
422 South Church Street
Charlotte, NC 28242

Anne Cottingham
Winston and Strawn
Electronic Mail Distribution

Beverly Hall, Acting Director
Division of Radiation Protection
N. C. Department of Environmental
Health & Natural Resources
Electronic Mail Distribution

Henry J. Porter, Director
Div. of Radioactive Waste Mgmt.
S. C. Department of Health and
Environmental Control
Electronic Mail Distribution

R. Mike Gandy
Division of Radioactive Waste Mgmt.
S. C. Department of Health and
Environmental Control
Electronic Mail Distribution

County Supervisor of
Oconee County
415 S. Pine Street
Walhalla, SC 29691-2145

Lyle Graber, LIS
NUS Corporation
Electronic Mail Distribution

M. T. Cash, Manager
Nuclear Regulatory Licensing
Duke Energy Corporation
526 S. Church Street
Charlotte, NC 28201-0006

Peggy Force
Assistant Attorney General
N. C. Department of Justice
Electronic Mail Distribution

Distribution w/encl:
L. Olshan, NRR
A. Hiser, NRR
L. Slack, RII, EICS
RIDSNRRDIPMLIPB
PUBLIC

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NAME	MShannon	GHutto	ERiggs	SVias	MScott	JBlake	DJones
DATE	7/28/2003	7/28/2003	7/28/2003	7/24/2003	7/24/2003	7/24/2003	7/28/2003
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO
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PUBLIC DOCUMENT	YES NO						

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:	50-269/03-03, 50-270/03-03, 50-287/03-03
Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7800 Rochester Highway Seneca, SC 29672
Dates:	April 6, 2003 - June 28, 2003
Inspectors:	M. Shannon, Senior Resident Inspector A. Hutto, Resident Inspector E. Riggs, Resident Inspector J. Blake, Senior Project Manager (Section 1R08) D. Jones, Senior Health Physicist (Section 4OA5.1D) G. Laska, Operator Licensing Examiner (Section 1R11.2) M. Scott, Senior Reactor Inspector (Sections 1R02 and 1R17) K. Maxey, Reactor Inspector (Sections 1R02 and 1R17) R. Cortes, Reactor Inspector (Sections 1R02 and 1R17) S. Vias, Senior Reactor Inspector (Sections 1R02, 1R17 and 40A5.1A-C) R. Carroll, Senior Project Inspector (Sections 1R20)
Approved by:	Robert Haag, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000269/2003-003, IR 05000270/2003-003, IR 05000287/2003-003; Duke Energy Corporation; 04/06/2003 - 06/28/2003; Oconee Nuclear Station; Maintenance Effectiveness, Personnel Performance During Non-routine Plant Evolutions, and Other Activities.

The inspection was conducted by the resident Inspectors and eight regional based inspectors: one senior project manager; one senior project engineer; one senior health physicist; two senior reactor inspectors; one operator licensing examiner; and two reactor inspectors. The inspectors identified four Green findings, which were identified as NCVs. 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: Mitigating Systems

- Green. A non-cited violation (NCV) of 10CFR50, Appendix B, Criterion XVI, Corrective Action, was identified by the inspectors for failure to promptly identify the degraded standby shutdown facility (SSF) diesel cooling water seals in the problem investigation process (PIP) program.

  This finding was considered to be more than minor based on the fact that subsequent analysis of the grommets noted significant degradation and this analysis would likely not have been performed without initiation of the PIP. Therefore, if the cause of the degradation was left uncorrected, the mitigation systems cornerstone objective of ensuring the continued reliability of equipment needed to respond to initiating events would be affected. In addition, continued degradation of the grommets would become a more significant safety concern. This issue was considered to be of low safety significance (Green) because the grommets were replaced during the SSF diesel overhaul before they failed in service. (Section 1R12.2)

- Green. A NCV of Technical Specification (TS) 5.4.1 and 10CFR50, Appendix B, Criterion XVII Quality Assurance Records, was identified by the inspectors for failure to maintain sufficient records [logs] to furnish evidence of activities affecting quality [TS Limiting Conditions for Operation (LCOs)]. Specifically, operator logs provided insufficient data to reconstruct the activities related to the June 22, 2003, Unit 1 Engineered Safeguards (ES) power supply failure, which affected the Engineered Safeguards Protection System (ESPS) Digital Automatic Actuation Logic Channels 2, 4, 6, and 8.

  The ESPS automatic initiation of ES functions to mitigate accident conditions is assumed in the accident analysis and is required to ensure that consequences of analyzed events do not exceed the accident analysis predictions. The failure to adequately document TS LCO entry and action times for the failed automatic ES actuation circuitry was considered to be more than minor because it impacted the operators' ability to accurately implement the TS LCO action statements, and if left uncorrected, this type of improper documentation could become a more significant safety concern. The finding was considered to be of very low safety significance based on the fact that the ES power supply was returned to service before any LCO condition would have required the unit to be in Mode 3. (Section 1R14b.(1))

- Green. A NCV of TS 3.3.7 Condition A , Engineered Safeguards Protection System (ESPS) Digital Automatic Actuation Logic Channels, was identified by the inspectors when it was discovered that the licensee failed to declare a number of ES configured system components inoperable following the loss of ESPS digital channels 2, 4, 6, and 8.

  The ESPS automatic initiation of ES functions to mitigate accident conditions is assumed in the accident analysis and is required to ensure that consequences of analyzed events do not exceed the accident analysis predictions. Consequently, this issue is more than minor, in that by not recognizing the importance of the lost automatic ES initiation function and taking the compensatory actions of TS 3.3.7, the mitigating systems cornerstone objective of ensuring the continued reliability of equipment needed to respond to initiating events was affected. However, this issue was determined to be of very low safety significance, based on the fact that there was no loss of function of the Low Pressure Service Water system or the Keowee Hydro Units resulting from the loss of ESPS Digital Automatic Actuation Logic Channels 2, 4, 6, and 8. Additionally, the ES power supplies were restored and digital channels returned to service prior to exceeding any TS allowed outage times for the affected components. (Section 1R14b.(2))

Cornerstone: Initiating Events

- Green: A NCV of 10CFR50.55a(g)(4) and 10CFR50, Appendix B, Criterion VII was identified by the inspectors, in that measures taken to preclude the installation of non-conforming replacement parts and the ability to evaluate the suitability of replacement during the Quality Assurance (QA) receipt inspection process were not adequate. Specifically, this was identified for inadequate QA review during receipt inspections that resulted in the licensee installing one non-conforming Control Rod Drive Mechanisms (CRDM) (Split Nut) Flange Ring on Unit 2, and discovering, prior to the installation in Unit 3, 68 CRDMs and 552 CRDM Hold Down Bolts that did not meet the design and procurement specifications.

  This finding was more than minor because non-conforming material was actually installed in Unit 2. However, it was determined to be of very low safety significance because there was not a loss of system function. (Section 40A5.1C)

B. **Licensee Identified Violations**

One violation of very low safety significance, which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation is listed in Section 4OA7.

Report Details

Summary of Plant Status:

Unit 1 operated at 100 percent rated thermal power (RTP) during the inspection period except for one power reduction. The unit was reduced to approximately 50 percent RTP on May 17, 2003, following a safety group 4 dropped rod. The rod was recovered and the unit was returned to 100 percent RTP on May 18, 2003.

Unit 2 operated at 100 percent RTP during the inspection period except for two power reductions. The unit was reduced to approximately 88 percent RTP on April 13, 2003, to perform turbine valve movement testing. The unit was returned to 100 percent power later that same day. On June 22, 2003, the unit was reduced to approximately 87 percent RTP to again perform turbine valve movement testing. The unit was returned to 100 percent power later that same day.

Unit 3 entered the report period at 93 percent RTP with an end of core life coastdown in progress. The unit was shutdown on April 26, 2003, for a refueling outage. Following the outage, the unit entered Mode 1 on June 14, 2003, and reached 100 percent RTP on June 18, 2003. On June 28, 2003, the unit was reduced to 15 percent RTP and the turbine taken off-line for turbine balancing. The report period ended with the unit at 15 percent RTP.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R02 Evaluations of Changes, Tests or Experiments

a. Inspection Scope

The inspectors reviewed selected samples of evaluations to confirm that the licensee had appropriately considered the conditions under which changes to the facility, Updated Final Safety Analysis Report (UFSAR), or procedures may be made, and tests conducted, without prior NRC approval. The inspectors reviewed evaluations for nine changes and additional information, such as calculations, supporting analyses, the UFSAR, and drawings to confirm that the licensee had appropriately concluded that the changes could be accomplished without obtaining a license amendment. The nine evaluations reviewed are listed in the Attachment to this report.

The inspectors also reviewed samples of changes such as design changes, UFSAR changes, commercial grade dedication packages, equipment problem issues, and like-for-like evaluations for which the licensee had determined that evaluations were not required, to confirm that the licensee's conclusions to "screen out" these changes were correct and consistent with 10CFR50.59. The twenty-one "screened out" changes reviewed are listed in the List of Documents Reviewed.

The inspectors also reviewed an audit of the 10CFR50.59 process and selected Problem Investigation Process reports (PIPs) to confirm that problems were identified at an appropriate threshold, were entered into the corrective action process, and appropriate corrective actions had been initiated.

b. Findings

(1) Introduction: One Unresolved Item (URI) was identified in that potentially the air temperature inside of the units' control room boards (vertical and unit boards) may reach a higher than anticipated value than previously understood during design basis events.

Description: During the review of an UFSAR change to Section 3.11.5, "Loss of Ventilation," the inspectors observed the control room area temperature maximum was stated to be 120 degrees F. The section did not address control board interior temperature rise nor did it discuss the maximum value that could be reached inside boards for the discussed event. The inspectors realized that other events not discussed in the reviewed section could cause a loss of forced ventilation to the boards. When the licensee was informed that the heat generating temperature sensitive electronics interior to the boards may see a higher temperature than the control room ambient temperature, PIP O-03-04052 was written on the issue. During normal operations, Technical Specification (TS) 3.7.16 limits the control room general area temperature to 80 degrees F.

The temperature difference between the ambient control room temperature and the interior temperature of the boards was not clearly documented. Forced ventilation to the boards and to the control room is postulated to be lost during such events as loss of offsite power and seismic occurrences. There is a degraded control room ventilation abnormal procedure. All related event and abnormal procedures do not address control board interior temperatures nor do they have special instructions for reducing the interior temperature of the boards during the loss of forced ventilation cooling. With the loss of forced ventilation, a rise in temperature inside the board may occur and this rise may be greater than that experienced in the control room inhabited space where control room temperature is measured. Such a rise may be detrimental to critical electronic equipment operation.

The aforementioned PIP stated that there was reasonable assurance that the equipment inside of the control boards is operable during the event scenarios. This was based on calculations that determined that the general area temperature rise after six hours would be approximately 90 degrees F (calculation OSC-6667). The licensee stated that the most limiting equipment in the boards has continuous duty temperature of 122 degrees F, which is 32 degrees F higher than the six hour rise value. The event and abnormal procedures are written to limit the time without forced ventilation. Further, the licencee indicated in PIP O-00-4643, that the time required to restore cooling following a loss of offsite power event was estimated to be less than 6 hours. PIP O-03-4052 indicated that an operability evaluation would be performed to further investigate the relationship between the temperature inside the main control boards and the control rooms on all three units.

The inspectors were aware that there are some passive vents and holes in the top of the control boards and louvers on the side of the boards could possibly dissipate board interior heat buildup. Further, the inspectors were aware of procedures and equipment in other locations that could be relied upon for safe shutdown purposes should the abandonment of the control room be required.

However, the following issues require additional review by the licensee: an understanding of the peak temperature reached in each unique control cabinet in each control room space; the critical electronic components needed for plant operation during the postulated events; the suitability of equipment in the control boards to withstand environmental temperature such as records documenting the component vendors' continuous duty temperatures for the considered critical parts; and, critical components locations relative to possible warm spots on the boards should also be understood (board thermal profile relative to component location).

Until the licensee can demonstrate a clear understanding of the thermal effects on control room board components during a postulated loss of control board forced cooling occurrence, this issue will be identified as URI 05000269,270,287/2003003-001: Control Room Board Component Thermal Reliability.

(2) Introduction: An URI was identified concerning Oconee UFSAR Section 3.6.1.3 that was changed on May 17, 2001, under the old 50.59 program revision. During a review of the change, the inspectors were concerned that the change may involve an unreviewed safety question (USQ) under the old rule or a departure from a method of evaluation under the new rule.

Discussion: The UFSAR change was associated with high energy line break (HELB) on a main feedwater line. The escaping water/steam is assumed to disable the 4160 Volt breakers for at least the motor driven emergency feedwater (EFW) pumps and for the high pressure injection HPI pumps. The change increased the time allowed for initiation of EFW and (HPI) after the HELB from 15 minutes to 30 minutes and from 1 hour to 8 hours, respectively.

The 1998 UFSAR version used RETRAN program analysis and the lower equipment recovery times that kept the reactor coolant system (RCS) subcooled and capable of natural circulation (minimally voided) due to the small amount of water loss. Under the May 2001 revision, the licensee used RELAP 5 program and extended times for equipment recovery of EFW and HPI. This results in significant voiding in the RCS, loss of subcooling, increased number of cycles of the pressurizer safety valves, loss of natural circulation, and reliance on the boiler/condenser mode (BCM) of decay heat removal for up to 8 hours without safety injection. Under BCM, the expansion and collapsing of the RCS remaining volume would cause some pressure spikes within the RCS. This evaluation was based on licensee calculation OSC-7299, Revision 1. Page 4 of the 10 CFR 50.59 evaluation discusses RELAP5 in that:

> "The analytical model utilized to evaluate these effects was changed from RETRAN to RELAP5 because of the significant RCS voiding that will occur and the importance of boiler condenser mode of decay heat removal. The version of RELAP5 used is similar [to] a version approved by the NRC for use by Frametone Technologies in small break loss of coolant accident (SBLOCA) UFSAR analysis of OTSG plants. Additionally, the NRC has approved this version for use by Duke

Power Company in both SBLOCA and large break loss of coolant accident (LBLOCA) mass and energy release analysis. The additional delays in EFW and HPI restoration result in a transient that is essentially a small break LOCA."

The inspectors were concerned that this change appears to represent an USQ, as defined by the previous version of 10 CFR 50.59. (The evaluation was completed under the old 10 CFR 50.59 rule on May 17, 2001, and the licensee implemented the revised rule on July 2, 2001). In this scenario, the pressurizer safety valves are challenged to lift and reseat multiple times while passing steam and then water until EFW is recovered. The licensee did not consider that the increased number of cycles of these valves would increase the probability of a malfunction (i.e., sticking open) and create the possibility of an accident of a different type (loss of coolant). With a stuck open valve and no safety injection, core damage would result. The licensee's evaluation states that RELAP 5 has been approval for LOCA analysis, but it is not clear as to the acceptability of this method of evaluation for HELB. Furthermore the concept of allowing the RCS to become significantly voided, saturated, without natural circulation, without HPI for eight hours, and reliance on BCM for decay heat removal, appears to be a departure from a method of evaluation as described in the UFSAR, which would require prior NRC approval under the current regulation. Until the NRC completes its review of the above issue, it will be identified as URI
05000269,270,287/2003003-002: HELB Accident Scenario Review.

1R04 Equipment Alignment

.1 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 systems were included in this review:

- Unit 2 HPI trains 2A and 2B while the 2C HPI pump was out of service for preventive maintenance

- Unit 2 train A low pressure injection (LPI) while the B train of LPI was out of service for maintenance

- Units 1 and 2 primary instrument air system with the backup instrument air compressor out of service for preventive maintenance

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown.

a. Inspection Scope

The inspectors conducted a detailed review of the alignment and condition of the Unit 3 component cooling (CC) system. The inspectors utilized licensee procedures and other documents listed in the Attachment to verify proper system alignment.

The inspectors also verified electrical power requirements, labeling, hangers, support installation, and associated support system status. The operating pump was examined to ensure that any noticeable vibration was not excessive, bearings were not hot to the touch, and the pump was adequately ventilated. The walkdown also included an evaluation of the system piping and supports against the following considerations:

- Piping and pipe supports did not show evidence of water hammer
- Hangers were properly sized and were within the setpoints
- Piping insulation was adequate and showed no evidence of prior system leaks
- Component foundations were not degraded

A review of PIPs and maintenance work orders was performed to verify that material condition deficiencies did not significantly affect the ability of the CC system to perform its design functions and that appropriate corrective action was being taken by the licensee.

The inspectors also held discussions with the system and design engineers on temporary modifications, future modifications, and operator workarounds to ensure that the impact on the equipment functionality was properly evaluated.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours in thirteen 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. Inspection of the following areas were conducted during this inspection period:

- Units 1 and 2 and Unit 3 HPI Rooms (2)
- Units 1, 2 and 3 Equipment Rooms (3)

- Units 1, 2 and 3 LPI/RBS Rooms (5)
- Keowee Hydro Units (2)
- Unit 2 Turbine Building Switchgear Area (1)

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

.1 Unit 3 Low Pressure Injection System Cooler Test

a. Inspection Scope

The inspectors reviewed TT/3/A/0150/061, Unit 3 Low Pressure Injection System Cooler Test, used to gather data for the LPI cooler performance evaluation. This testing was performed to ensure that the cooler is able to meet TS and design basis requirements. The inspection focused on compliance with the procedure requirements and appropriate data collection during the testing. The inspectors also reviewed design calculation OSC - 4338 Revision 7, to ensure that the LPI heat exchanger, based on the test data, was capable of performing its design function per the calculation.

b. Findings

No findings of significance were identified.

.2 Unit 1 Reactor Building Cooling Units (RBCU) Performance Test

a. Inspection Scope

The inspectors reviewed Unit 1 RBCU Performance Test, PT/0/A/0160/006, used to gather data for the RBCU performance evaluation. This testing was performed to verify that the RBCU cooling capacity meets TS and design basis requirements. The inspection focused on compliance with the procedure requirements and appropriate data collection during the testing. The inspectors also reviewed design calculation OSC - 5665, Attachment 27, which calculated the RBCU capacity factors from the obtained test data.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities

a. Inspection Scope

Unit 3 Steam Generator (SG) Inspection

The inspectors reviewed the implementation of the licensee's program for monitoring the performance of the U3 once-through steam generators (OTSG). The inspector observed examinations and reviewed selected inspection records for:

- Eddy current examination (ET) data for eleven OTSG tubes.

- Tube plugging operations including quality control verification of tube locations.

- In-situ pressure testing data used to evaluate SG tube structural and leak tight integrity of thirteen SG tubes (twelve in SG A and one in SG B)

- Certifications for ten Quality Assurance (QA) Level III Eddy Current Data Analysts

- SG tube repair (plugging) lists generated as a result of the Unit 3 SG ET inspection.

The above activities and records were compared to the TS, License Amendments, and applicable industry established performance criteria to verify compliance. Documents reviewed are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Simulator Scenarios

a. Inspection Scope

The inspectors observed licensed operator simulator training on June 27, 2003. The scenario involved a dropped rod, a reactor trip, a steam generator tube leak in the 1B steam generator, and a main steam line break. The inspectors also observed entry into the emergency action levels (Unusual Event and Alert). The inspectors observed crew performance in terms of: communications; ability to take timely and proper actions; prioritizing, interpreting, and verifying alarms; correct use and implementation of procedures, including the alarm response procedures; timely control board operation and manipulation, including high-risk operator actions; and oversight and direction provided by the shift supervisor, including the ability to identify and implement appropriate TS actions.

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results

a. Inspection Scope

Following the completion of the annual operating examination testing cycle, which ended on May 9, 2003, the inspectors reviewed the overall pass/fail results of the biennial written examination, the individual Job Performance Measure operating tests, and the simulator operating tests administered by the licensee during the operator licensing requalification cycle. 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

.1 Routine Maintenance Effectiveness Reviews

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 item:

PIP O-03-02888, Turbine Driven Emergency Feedwater Pump Steam Nozzle Bolt Failure Issue

b. Findings

No findings of significance were identified.

.2 Effectiveness of Standby Shutdown Diesel Preventive Maintenance and Problem Identification

a. Inspection Scope

The inspectors observed the 10-year overhaul of the Standby Shutdown Facility (SSF) diesel, and selected for further review, those problems which were identified by outside contractors. Specifically, the inspectors reviewed problems being identified by Engine Service, Inc. contractors who were contracted by the licensee to provide technical oversight for the 10-year overhaul of the SSF diesel engines and to assist with the maintenance activities. For this inspection activity, the inspectors reviewed the daily field service reports provided by the contractors to the licensee to evaluate the adequacy of previous maintenance activities and to verify that problems identified by the contractors were being appropriately documented in the licensee's corrective action program.

b. Findings

Introduction: Two separate issues were identified as a result of this inspection:

(1) A Green non-cited violation (NCV) was identified by the inspectors for failure to promptly identify degraded SSF diesel cooling water seals in the PIP program.

(2) An URI was identified, in that the licensee failed to implement the 6-year recommended diesel manufacturer (EMD) preventive maintenance grommet replacements. Consequently, at 10 years some of the grommets were found to be "at or near failure". Failure of the grommets could have led to diesel coolant leaks and loss of cooling to the diesel. This issue will remain unresolved pending completion of a Phase 3 risk review.

Description: During the June 2002, SSF diesel overhaul, the inspectors discussed diesel equipment problems with the maintenance contractors from Engine Systems, Inc. (ESI) who were providing technical oversight for the SSF diesel overhaul. The day shift ESI contractor noted that the SSF diesel coolant grommets, located on the cylinder heads (power packs), had been found degraded. He informed the inspectors that this adverse condition would be provided to the licensee in a daily field service report. The inspectors subsequently discussed the degraded grommet condition with maintenance management to ensure that they were aware of the potential problem. The June 18, 2002, ESI daily field service report documented that Cylinder 7 on Engine B, "had deformed grommets on the cylinder head, unable to determine if the deformities were from overheating or from installation damage." The June 19, 2002, ESI daily field service report documented that Cylinder 8 on Engine A, "had deformed head grommets."

On June 27, 2002, prior to returning the diesel to service and after noting that a PIP report had not been initiated, the inspectors discussed the deformed grommet issue with licensee management. On June 28, 2002, PIP O-02-03526 was initiated to capture the potential degraded grommet condition.

Subsequent discussions with engineering noted that some of the deformed grommets were going to be sent off for analysis. At this time, the inspectors also noted that the grommets from Cylinder 7 on Engine B and Cylinder 8 on Engine A had not been segregated from the grommets from the other 26 cylinders. It was also noted that the licensee could not account for all of the replaced grommets, in that only 282 of the 336 replaced grommets could be located.

During various discussions regarding the grommets, the licensee noted that the diesel manufacturer (EMD) had recommended a 6-year replacement interval for these grommets. However, the grommets were being replaced on a 10-year interval and the EMD owners' group was discussing the possibility of EMD changing the replacement interval to 12 years.

In October 2002, the remaining 282 grommets were sent off to ESI for analysis. On May 8, 2003, the results of the ESI analysis were received by the licensee. The report noted that "Diesel engines used in standby service see thermal cycling which contributes to the hardening of these grommets. Therefore, the recommended replacement interval is on a 6 year calendar basis." ESI's analysis concluded the following: 31 grommets were approaching the end of life; 6 grommets had been torn during removal and that "a new grommet cannot be readily torn by hand", "the ability to tear these grommets indicates their pliability has been compromised, likely due to aging" and "their brittle nature indicates they were near the end of life"; 43 grommets "show a high degree of brittleness and degradation, these are considered abnormal to a typical reseal interval", "It can be assumed these grommets were still capable of performing their sealing function", and "the state of brittleness and separation they exhibit indicates they have exceeded their useful life"; and last 19 grommets were "distorted into a "D" shape, considered to be classic examples of cylinder combustion leaks" and "with no reported leaks, it must be assumed they performed their sealing function; however, these grommets have exceeded their useful life." EMD went on to state that "Continued operation with grommets exposed to combustion gases will lead to failure and coolant leaks."

EMD concluded the analysis with the following: "Many of the components examined in this investigation were at or near failure, and although no coolant leaks were reported, combustion leaks were definitely occurring in some cylinders. Coolant leaks were likely to follow, as those cylinders' grommets exposed to combustion gases would have continued to decay until their sealing ability was exhausted." EMD also stated that "Diesel engines in standby service experience more severe thermal cycling at each surveillance run as compared to engines in continuous duty. This thermal cycling promotes age-hardening in these seals, and the recommended 6-year maintenance interval is a preventive maintenance practice that must be adhered to for continued reliability."

Analysis

The issue of not initially writing a PIP to capture the ESI identified grommet degradation was considered to be greater than minor based on the fact that subsequent analysis of the grommets noted significant degradation and this analysis would likely not have been performed without initiation of the PIP. Therefore, if the cause of the degradation was left uncorrected, the mitigation systems objective of ensuring the continued reliability of equipment needed to respond to initiating events would be affected. In addition, continued degradation of the grommets would become a more significant safety concern. This issue was considered to be of low safety significance (Green) because the grommets were replaced during the SSF diesel overhaul before they failed in service.

The issue of not performing the recommended grommet replacements was considered to be more than minor in that the degraded grommets affected the equipment reliability of a mitigation system (i.e., the SSF diesel). The finding was first evaluated in the Phase 1 SDP based on the degraded reliability of a mitigating system under the Reactor Safety Cornerstone. Based on the manufacturer's conclusion that the grommets had exceeded their useful life and that continued operation with grommets exposed to combustion gases would lead to failure and coolant leaks, it was assumed that the finding represented an actual loss of safety function of the SSF diesel, as the loss of coolant could preclude operation of the diesel for its 72 hour mission time. Since this system was designated as a risk significant system per 10 CFR 50.65, a Phase 2 analysis was performed. The Phase 2 analysis indicated that the issue could be greater than Green; therefore, a Phase 3 analysis was required. Pending completion of the Phase 3 analysis, the issue of not implementing the manufacturer's recommendations for replacement of the SSF diesel coolant grommets will be identified as URI 05000269,270,287/2003003-03: Failure to Implement Manufacturer's Recommendations for Replacement of SSF Diesel Coolant Grommets. This issue is in the licensee's corrective action program as PIP O-02-03526.

Enforcement

10 CFR 50, Appendix B, Criterion XVI, requires that measures shall be established to assure that conditions adverse to quality, such as...deficiencies, deviations, defective material and equipment, and non-conformance's are promptly identified. The licensee's quality assurance (QA) program implements this requirement through Nuclear Station Directive 208, Problem Investigation Process, Revision 22. Section 208.6, Problem Identification, states that a PIP should be initiated within 24 hours of recognition of the issue. Contrary to 10 CFR 50 Appendix B, Criterion XVI, following the June 19, 2002, identification of the degraded grommets which could be the result of improper installation, a PIP was not initiated until June 28, 2002, which was after all of the SSF diesel grommets had been replaced. This inadequate corrective action issue is being treated as an NCV, consistent with Section VI.A.1 of the enforcement policy and is identified as NCV 05000269,270,287/2003003-04: Failure to Identify the SSF Degraded Grommets as a Deficient Condition in the PIP Corrective Action Program. This issue is in the licensee's corrective action program as PIP O-02-03526.

1R13 Maintenance Risk Assessment and Emergent Work Evaluations

a. Inspection Scope

The inspectors evaluated, as appropriate for the selected SSCs 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.

- PIP O-03-3584, Unexpected Closure of 1HP-5 Letdown Isolation Valve, caused by failure of an improperly installed control air solenoid
- IP/0/A/2005/003, Keowee Hydro Station Westinghouse Voltage Regulator Test, performed as part of troubleshooting for failed voltage regulator
- PIP O-03-2925, Increased HPI Motor Cable Insulation Leakage
- Preventive Maintenance on Unit 2 Electro Hydraulic Control (EHC) System per Work Orders 98592430 and 98592429
- PIP O-03-3800, Unit 3 RC-4 Power Operated Relief Valve (PORV) Block Valve Leakage and Repair
- PIP O-03-02381, 3MS -155 (Main Steam Line B Atmospheric Vent) could not be opened when attempting to depressurize the steam generator
- PIP O-03-04140, Identification of Risk Assessment Error for Previous Repair of 3RC-4. Credit was inappropriately given for availability of the steam generators although the RCS loops were not filled.

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 evolution reviewed during this inspection period included the following:

- Loss of 700 Gallons of RCS in Unit 3 Due to Over-pressurization of LPI Suction (PIP O-03-02362)
- Unit 1 Dropped Rod and Subsequent Recovery
- Failure of the Unit 1 Channel B Engineered Safeguards (ES) Power Supply

b. Findings

(1) Introduction: A Green NCV was identified by the inspectors for failure to maintain sufficient records [logs] to furnish evidence of activities affecting quality [TS Limiting Conditions In Operations (LCOs)].

Description: On June 22, 2003, the Unit 1 ES channel B power supply failed. This failure, caused a loss of power to the Engineered Safeguards Protection System (ESPS) Digital Automatic Logic Channels 2, 4, 6, and 8. Subsequently, the inspectors reviewed the licensee's operator logs and TS tracking systems. The inspectors noted that the operator logs provided insufficient data to reconstruct the activities related to the ES power supply failure. The inspectors noted that the documented time for declaring the components related to ES channels 2, 4, 6, and 8 per TS 3.3.7, had been improperly changed and backdated from 9:55 a.m. to 9:15 a.m. In addition, the time of discovery of the failed power supply was backdated to 8:15 a.m., although the ES channel B power supply was functioning properly at that time. The logs did not provide any justification for this change. Also, the inspectors noted that the logs indicated the control room operators were informed of the loss of power to the ES digital channels at 8:51 a.m.; however, the TS tracking documents noted that the ES digital channels became inoperable at 8:55 a.m. The various times were considered to be important because they provided evidence for activities associated with meeting the 1 hour action statement of TS 3.3.7 for placing the associated components in their ES positions or declaring the components inoperable.

Analysis: The ESPS automatic initiation of ES functions to mitigate accident conditions is assumed in the accident analysis and is required to ensure that consequences of analyzed events do not exceed the accident analysis predictions. The failure to adequately document TS LCO entry and action times for the failed automatic ES actuation circuitry was considered to be more than minor because it impacted the operators' ability to accurately implement the TS LCO action statements, and if left uncorrected, this type of improper documentation could become a more significant safety concern. The finding was considered to be of very low safety significance (Green) based on the fact that the ES power supply was returned to service before any LCO condition would have required the unit to be in Mode 3. This observation was based on the inspectors' review of the associated completed surveillances and use of computer alarm summaries as a basis for the initial failure time.

Enforcement: TS 5.4.1 requires that written procedures be established, implemented, and maintained covering activities related to procedures recommended in Regulatory Guide 1.33 Rev. 2, Appendix A, 1978. Regulatory Guide 1.33, Section 1(g), Administrative Procedures, requires log entries. 10 CFR 50, Appendix B, Criterion XVII, Quality Assurance Records, requires that sufficient records shall be maintained to furnish evidence of activities affecting quality. Contrary to the above, sufficient logkeeping and TS tracking records were not sufficiently maintained to furnish evidence of activities related to TS LCO action statements. Because the finding is of very low safety significance and has been entered into the corrective action program as PIP O-03-04408, this violation is being treated as NCV 05000269/2003003-05: Failure to Maintain Sufficient Records (logs) to Furnish Evidence of Activities Affecting Quality (TS LCOs).

(2) Introduction: A Green NCV of TS 3.3.7 Condition A , Engineered Safeguards Protection System (ESPS) Digital Automatic Actuation Logic Channels, was identified by the inspectors when it was discovered that the licensee failed to declare a number of ES configured system components inoperable following the loss of ES digital channels 2, 4, 6, and 8 as required.

Description: As indicated in (1) above, the June 22, 2003, power supply failure of Unit 1 ES Analog Channel B resulted in the subsequent loss of Unit 1 ES Digital Actuation Channels 2, 4, 6, and 8. Upon declaring one or more ES digital automatic actuation logic channels inoperable, TS LCO 3.3.7 Condition A .1, requires that ES configured components associated with that channel be placed in their ES configuration, or Condition A.2 requires that the components associated with that channel be declared inoperable. The inspectors determined that the licensee failed to either place the affected components in their ES configuration or declare them inoperable within one hour as required by the TS. Since placing the affected components in their ES configuration would in this case violate unit safety or operational considerations, the licensee was required to declare the components inoperable within one hour and enter the associated component TS LCO. Specifically, the licensee failed to enter TS 3.3.17 Condition A, one channel of the emergency power switching logic (EPSL) automatic transfer function inoperable [channel B from ES channel 2], TS 3.3.21 Condition A, one channel of the EPSL Keowee Hydro Unit (KHU) emergency start function inoperable [channel B from ES channel 2], and TS 3.7.7 Condition A, one required low pressure service water (LPSW) pump inoperable [LPSW pump B from ES channel 4].

Analysis: The ESPS automatic initiation of ES functions to mitigate accident conditions is assumed in the accident analysis and is required to ensure that consequences of analyzed events do not exceed the accident analysis predictions. Consequently, this issue is more than minor, in that by not recognizing the importance of the lost automatic ES initiation function and taking the compensatory actions of TS 3.3.7, the mitigating systems cornerstone objective was affected. However, this issue was determined to be of very low safety significance (Green), based on the fact that there was no loss of function of the LPSW system or the KHUs resulting from the loss of ESPS Digital Automatic Actuation Logic Channels 2, 4, 6, and 8. Additionally, the ES power supplies were restored and digital channels returned to service prior to exceeding any TS allowed outage times for the affected components.

Enforcement: TS 3.3.7 Condition A .1 requires that ES configured components associated with an inoperable ESPS Digital Automatic Actuation Logic Channel be placed in their ES configuration, or TS 3.3.7 Condition A.2 requires that the components associated with the inoperable channel be declared inoperable. Contrary to the above, the licensee failed to place all effected ES components in their ES configuration or declare the associated components inoperable following the loss of ES digital channels 2, 4, 6, and 8. Because this finding is of very low safety significance and has been entered into the corrective action program as PIP O-03-04408, 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 05000269/2003003-06: Failure to Declare ES Configured Components Inoperable per TS.

1R15 Operability Evaluations

Quarterly Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected operability evaluations affecting risk significant mitigating 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 LCO. The inspectors reviewed the following items for operability evaluations:

- PIP O-03-02132, Unit 2 Installed Control Rod Drive Mechanism (CRDM) Split Ring Flange Assembly Does Not Meet ASME Requirements

- PIP O-03-03042 Increased Containment Sump Leakage in Unit 1 From RCS and LPSW Leakage

- PIP O-03-02226, 2B and 1C HPI Motor Vibration Increase Following New Pump Installations

- PIP O-03-3183, Increased Leakage From the 1B1 RCP Seal

- PIP O-03-02492, Unit 1 RCS Leakage From Incore Instrument Tank

- PIP O-03-3036, The 1A LPI Motor Space Heaters Have Not Functioned Since June 2001

- PIP O-03-02569, Evidence of Borated Water Leakage Down Inside Primary Shield Walls Below the Unit 3 Reactor Vessel

- PIP O-03-02268, Indications of Increased RCS Leakage in Unit 1

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

.1 Feedwater Whip Restraint Modification

a. Inspection Scope

The inspectors reviewed minor modification (ONOE) -17539, Modify Two Pipe Whip Restraints on Unit 3 Main Feedwater Piping, to verify that the feedwater whip restraints had been properly adjusted as per the design drawings following replacement of the bolting material and clevises.

The inspectors observed work in progress during the removal and replacement of the whip restraints and reviewed the work documentation for setting the whip restraints following return to normal operating temperatures of the feedwater piping.

The inspectors reviewed the following documents during the inspection:

- NSM ONOE-17539
- MP/O/A/3019/004, Revision 53, Hangers - QA Condition 1 and 4 - Removal, Installation or Modification
- Work Request/Work Orders 98590970 (11) making final adjustments hot
- Design Drawing O-494, Main Feedwater Pipe Whip Restraint
- PIP O-01-01408, Adequacy of Existing Feedwater Pipe Rupture Restraints, Corrective Action 7

In addition, the inspectors discussed with engineering the adjustments made to the whip restraints once hot temperature operations were reached.

b. Findings

No findings of significance were identified.

.2 Biennial Plant Modification Review

a. Inspection Scope

The inspectors evaluated design change packages for nine modifications in the Barrier Integrity and Mitigating Systems cornerstone areas, to evaluate the modifications for adverse affects on system availability, reliability, and functional capability. The modifications and the associated attributes reviewed are as follows:

ONOE- 10642, Upgrade Seismic Supports and Add Isolation Valve 3N-305 to Nitrogen Line
- Materials/Replacement Components
- Flowpaths
- Pressure Boundary
- Structural
- Process Medium
- Failure Modes

ONOE- 12107, Upgrade Discharge LPSW Piping from the Motor Driven EFW coolers to 1LPSW-527
- Materials/Replacement Components

- Structural
- Process Medium

ONOE- 15414, Replace Valve 2LP-15 with Item DMV-1296, 2A LPI Discharge to RBS Pump Spray and HPI Suction
- Materials/Replacement Components
- Pressure Boundary
- Structural

ONOE- 12094, Modification of Unit 2 RC Vent System Supports/Restraints
- Materials/Replacement Components
- Structural

ONOE- 12800, Provide Clearance Between the Valve Body of 2SF-101 and SSF RC Makeup Pump Discharge Piping
- Materials/Replacement Components
- Pressure Boundary
- Structural

ONOE- 17011, Upgrade 3-CCW-269 to Meet EQ Requirements
- Materials/Replacement Components

Nuclear Station Modification (NSM) 33090, Add RBCU Time Delay Relays
- Energy needs
- Seismic qualification
- Response time
- Operations procedures
- Modes bounded by the existing analysis

NSM 23053, Automatic Feedwater Isolation System
- Environmental Qualification
- Response Time - Testing
- Modes bounded by existing analysis

NSM 23092, 600 V MCC and Load Center
- Energy Needs
- Seismic qualification
- Control signals appropriate under accident conditions
- Failure modes bounded by the existing analysis

For selected modification packages, the inspectors observed the as-built configuration. Documents reviewed included procedures, engineering calculations, modifications design and implementation packages, work orders, site drawings, corrective action documents, applicable sections of the UFSAR, supporting analyses, TS, and design basis information. Documents reviewed are listed in the Attachment to this report.

The inspectors also reviewed selected PIPs associated with modifications to confirm that problems were identified at an appropriate threshold, were entered into the corrective action process, and appropriate corrective actions had been initiated.

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 mitigating 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 tests:

- PT/2/A/0202/11, 2C High Pressure Injection Pump Inservice Testing (IST) Following Mechanical Seal Cleaning and Inspection
- PIP O-03-02797, Anderson Greenwood Relief Valves 3MS-52 and 3MS-70 Failed to Lift as Specified Pressure During IST
- PIP O-03-02864, 3HP-25, BWST Supply to LPI Suction, Failed IST Stroke Test
- PIP O-03-02831, 3HP23, Letdown Storage Tank Outlet Isolation, Failed IST Stroke Test
- PT/3/A/0152/007, Core Flood System valve Stroke Test, IST Stroke Test Following Inadvertent Backseating of Core Flood Isolation Valve 2CF-2 During Maintenance per PIP O-03-03061
- IP/0/A/0203/001A, Low Pressure Injection System Borated Water Storage Tank Level Instrument Calibration, calibration of level instrument reviewed following indication of false level reading per PIP O-03-0316
- TT/3/A/0600/022, Turbine Driven Emergency Feedwater (TDEFW) Pump Speed Response During AFIS Initiation Test, Following AFIS Modification
- PIP O-03-02955, Following Maintenance the Unit 3 TDEFW Pump Lube Oil Cooler Developed a Water Leak

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors conducted reviews and observations for selected licensee 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 26, 2003, and June 15, 2003, the following activities related to the Unit 3 refueling outage were reviewed for conformance to the applicable procedure and selected activities associated with each evaluation were witnessed:

- defueled (no Mode) operations
- refueling operations
- reduced inventory and mid-loop conditions for installation and removal of steam generator nozzle dams
- activities involving the reactor vessel head replacement
- reactor startup
- Mode changes from Mode 6 (Refueling) to Mode 1 (Power Operation)
- system lineups during major outage activities and Mode changes
- final containment walkdown prior to startup

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 selected risk-significant SSCs listed below, to assess, as appropriate, whether the SSCs met TS, 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 /1/A/0600/013, 1A Motor Driven Emergency Feedwater Pump Test [IST]
- PT/3/A/0151/20, Penetration 20 Leak Rate Test (3PR-1 and 3PR-2) [local leak rate test (LLRT)]

- PT/3/A/0151/019, Penetration 19 Leak Rate Test (3PR-5 and 3PR-6) [LLRT]

- PT/0/A/0600/021, Standby Shutdown Facility Diesel Generator Operation
- PT2/A0202/011, 2B HPI Pump test [IST]

- PT/3/A/0251/019, Main Steam Atmosphere Dump Valve Functional Test

- 1P/0/A/0305/001P, Reactor Protective System Channel D RC Pressure Instrument Calibration

- IP/A/0380/004C, SSF D/G Water Expansion Tank Level Instrument Calibration

- IP/0/A/305/0005D Reactor Building High Pressure Trip Channel D

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed and evaluated the licensee's conduct of a simulator based emergency preparedness drill held on June 10, 2003. The drill scenario involved tornado damage to the Unit 1 turbine building with a subsequent loss of all AC power. Additionally, Unit 3 developed a steam generator tube leak as part of the drill scenario. The inspectors observed the scenario from the simulator control room and the Technical Support Center. The inspectors observed performance of the licensee's ability to correctly classify the event and notify state and county authorities. For this drill, the scenario progressed to a site area emergency. The drill scenario did not provide an opportunity for the emergency response organization to make protective action

recommendations. The inspectors also reviewed the post-drill critique that was conducted by the licensee evaluators.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Initiating Events, Mitigating Systems, and Barrier Integrity Cornerstones

a. Inspection Scope

The inspectors reviewed the PIs listed in the table below (for all three units), to determine their accuracy and completeness against requirements in Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 2.

Cornerstone: Initiating Events		
Performance Indicator	*Verification Period*	*Records Reviewed*
Unplanned Scrams Scrams with Loss of Normal Heat Removal Unplanned Power Changes	3rd and 4th quarter, 2002, and 1st quarter, 2003	• Licensee Event Reports • NRC Inspection Reports • Monthly Operating Reports • operator logs • licensee power history curves

Cornerstone: Barrier Integrity		
Performance Indicator	*Verification Period*	*Records Reviewed*
Reactor Coolant System Specific Activity	3rd and 4th quarter, 2002, and 1st quarter, 2003	• daily plant chemistry data
Reactor Coolant System Leakage		• daily status reports • operator logs • PIPs

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed an in-depth review of issues entered into the licensee's corrective action program. The samples selected were within the cornerstone of mitigating systems 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 the safety significance

- Identification of the root cause and contributing causes of the problem

- Identification and implementation of corrective actions commensurate with the safety significance of the issue

The following issue and corrective actions were reviewed:

- PIP O-03-02482, Darkened Oil Found in the 2C LPI Pump Bearing

b. Findings

No findings of significance were identified.

4OA3 Event Followup

.1 Unit 1 Dropped Rod

On May 17, 2003, Unit 1 dropped Safety Group 4, Rod 9 during rod movement verification surveillance testing at 100 percent RTP. The dropped rod was a result of a blown fuse on one of the control rod drive motor phases. The operators reduced power to less than 55 percent as a result of the dropped rod. The inspectors responded to the site and verified that TS and core operating limits report requirements were met by the licensee for quadrant power tilt ratio, axial flux, and rod alignment. The inspectors also verified that the appropriate abnormal operating procedures were implemented by the operators. Repairs were made, the rod was subsequently recovered, and the unit was returned to 100 percent power on May 18, 2003.

.2 Standby Shutdown Facility Cable Routing

The inspectors followed up on a 10 CFR 50.72, eight hour notification made by the licensee for an unanalyzed condition relating to the licensee's discovery of safe shutdown cabling routed through an Appendix R, III.G.3 area. These cables included control and indication wiring for several valves that isolate the reactor coolant system from potential leakage paths during safe shutdown. The inspectors walked down the cabling to verify the licensee’s assessment of the condition and reviewed the adequacy of the compensatory measures put in place.

.3 Failure of the Engineered Safeguards Channel B Power Supply

The inspectors reviewed the licensee’s response to the failure of the engineered safeguards channel B power supply. The failure resulted in multiple TS LCO entries and included a loss of the digital engineered safeguards digital actuation circuits. In addition, multiple alarms were received in the control room. Following the initial loss, discussions were conducted with the licensee concerning the failure of the power supply, the various TS LCO entries, and ongoing repair efforts. Followup of the ES power supply failure is discussed further in Section 1R14 of this report.

4OA5 Other Activities

.1 Unit 3 Reactor Vessel Head Replacement Project (RVHRP)

A. Engineering Preparation and Implementation for the RVHRP

a. Inspection Scope

The inspectors reviewed engineering preparations including: selected Design Modification Packages, engineering calculations, analyses, and drawings for the Oconee RVHRP, in order to assess adequacy and completeness. To obtain a greater understanding of the entire project scope, the inspectors also held discussions with project management. To determine that proper Code Sections and Editions were applicable for this RVHRP, the inspectors also reviewed applicable sections of the Oconee Final Safety Analysis Report and various scope documents.

b. Findings

No findings of significance were identified.

B. Review of RVHRP Lifting and Transportation Program Activities

a. Inspection Scope

The inspectors reviewed the adequacy of the RVHRP lifting program as described in Modification Package ON-33112, Part AS1, “Reactor Vessel Head Rigging and Handling”, assuring that it was prepared in accordance with regulatory requirements, appropriate industrial codes and standards, and verified that the maximum anticipated loads to be lifted would not exceed the capacity of the lifting equipment and supporting structures.

The inspectors examined the RVHRP lifting equipment including the Polar Crane, a down-ender placed inside the Reactor Building, three four-point lift systems, three skid systems and a Self Propelled Modular Transport.

The inspectors reviewed the adequacy of the transport programs, procedures, work packages, and load test records, to assure that they had been prepared and/or tested in accordance with regulatory requirements, appropriate industrial codes, and standards.

The inspectors also reviewed the licensee's analyses for buried piping located beneath the transport path as documented in Modification Package ON-53112, Part AS4, “Reactor Vessel Head Transport”, to ensure that piping would not be damaged.

b. Findings

No findings of significance were identified.

C. Quality Assurance (QA) Oversight

a. Inspection Scope

The inspectors reviewed licensee procedures relative to QA oversight of contractor activities for the RVHRP replacement. In addition, the inspectors discussed procurement and quality control inspection of various parts, including the Control Rod Drive Mechanisms (CRDM), Hold Down Bolts, and CRDM (Split Nut) Flange Ring that were utilized in the attachment of the CRDMs to the Reactor Vessel CRDM flanges. The inspectors also reviewed a sample of PIPs, non-conformance reports, Purchase Orders, and Receiving Inspection Reports (Form SCD-311A) pertaining to the above parts. The inspectors also reviewed the “Unit 3 Reactor Vessel Head Penetration Preservice Inspection” conducted in February 2003. The Unit 3 Oconee replacement reactor vessel head contains sixty-nine alloy 690 penetration tubes that are shrunk fit in the reactor vessel head and attached with alloy 152/52 partial penetration J-groove welds. The inspectors reviewed aspects of the inspection program that provided a baseline of the condition of the accessible outside diameter and inside diameter surfaces of the vessel head penetration tubes and the partial penetration J-groove welds attaching the penetration tubes to the reactor vessel head. The review included Scope of Work, Procedures, Personnel Certifications, Equipment Certifications, and examination results.

b. Findings

Introduction: The inspectors identified a Green NCV of 10CFR50.55a(g)(4), which requires meeting the ASME Boiler and Pressure Vessel Code, Section XI, IWA-7000, Replacement, and of 10 CFR 50, Appendix B, Criterion VII, Control of Purchased Material, Equipment, and Services. This resulted in the licensee installing one non-conforming CRDM (Split Nut) Flange Ring on Unit 2, assembly #18, and discovering prior to the installation in Unit 3, 68 CRDM (Split Nut) Flange Rings and 552 CRDM Hold Down Bolts that did not meet the design and procurement specifications.

Description: In April 2003, while the licensee was performing an inspection during the replacement of the reactor vessel head project, they determined that the CRDM Hold Down Bolts, and CRDM (Split Nut) Flange Rings did not receive proper QA reviews of the mechanical/chemical properties and non-destructive examinations (NDE) as specified in the procurement and design specifications. These reviews and testing were conducted during the initial mechanical/chemical and NDE testing performed by independent testing facilities, and subsequently during the receipt inspections performed by Framatome ANP, who was acting as the contractor for the RVHRP project, and finally the licensee.

While performing Supply Chain Directive, SACD311, Rev. 1, “Receipt Inspection & Testing of QA Condition Items”, the licensee failed to identify that the CRDM (Split Nut) Flange Rings did not meet the required design and procurement specifications (i.e., a yield strength of 100 ksi and a tensile strength of 125 ksi) for material quality as stated in the Certificate of Compliance and as defined by ASME SA-320, Grade L43. The CRDM (split nut) flange rings also did not meet the NDE ultrasonic testing (UT) as described in ASME Section III, Sub-Article NB-2580 Examination of Bolts, Nuts and Studs, specifically NB-2586 Ultrasonic Examination for Sizes Over 4 in., requiring the examination be performed at a nominal frequency of 2.25 Mhz. Also the 552 CRDM Hold Down Bolts for Unit 3 did not meet the same NDE-UT testing as described in ASME Section III, Sub-Article NB-2580 Examination of Bolts, Nuts and Studs. Although not a code requirement, the examination was called for by the design and procurement specification.

A QA review, performed prior to installation of the components during Unit 3 End of Cycle (EOC) 20 refueling outage (RFO) in the spring of 2003, led to the identification of of one non-conforming CRDM (Split Nut) Flange Ring for CRDM Assembly #18 installed on Unit 2 during the Unit 2 U2EOC19 RFO in the fall of 2002, and removal of 68 uninstalled, non-conforming CRDM (Split Nut) Flange Rings from the site for failure to meet the mechanical property requirements of the components. This non-conforming condition was not identified during the Unit 2 EOC19 RFO.

Based on the discovery that one non-conforming CRDM (Split Nut) Flange Ring was installed on Unit 2, the licensee performed an engineering evaluation that is documented in Framatome ANP Document 32-5027297-00, Operability Assessment of CRDM Nut Ring with Reduced Tensile Strength Material. The one CRDM (Split Nut) Flange Ring installed on Unit 2 was declared to be operable, but degraded, and could remain in place until the end of the current Unit 2 operating cycle (which is scheduled to end in the spring of 2004) when the reactor vessel head will be replaced. New CRDM (Split Nut) Flange Rings with different heat numbers were procured and installed on the Unit 3 head. The inspectors reviewed the methodology utilized in the engineering evaluation for the non-conforming flange ring and found that the review was thorough. The evaluation involved the redoing of all the ASME Code-required calculations for the connection using the actual strength of the material supplied rather than the minimum strength required by the material specification.

Analysis: The inspectors determined that this finding was associated with an inadequate receipt inspection for the above parts. The finding was more than minor because non-conforming material was actually installed in Unit 2. This deficiency was evaluated under the SDP. Since there was no loss of function, the Initiating Events and Mitigation Systems cornerstones were not impacted. The SDP Phase 1 RCS Barrier cornerstone required an evaluation under SDP Phase 2. A regional senior reactor analyst performed a SDP Phase 3 analysis and determined that since there was not a loss of function of the system, there was no increase in risk. The finding was evaluated as Green (very low safety significance).

Enforcement: 10CFR50.55a(g)(4) specifies in part that components classified as ASME Code Class 1, Class 2, and Class 3 meet the requirements set forth in Section XI of the ASME Boiler and Pressure Vessel Code. The ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition, with no Addenda, subsection IWA-7220, states in part that "Prior to authorizing the installation of an item to be used for replacement, the Owner shall conduct an evaluation of the suitability of that item."

Also, 10CFR50, Appendix B, Criterion VII, Control of Purchased Material, Equipment, and Services, states that “Measures shall be established to assure that purchased material, equipment, and services, whether purchased directly or through contractors and subcontractors, conform to the procurement documents. These measures shall include provisions, as appropriate, for source evaluation and selection, objective evidence of quality furnished by the contractor or subcontractor, inspection at the contractor or subcontractor source, and examination of products upon delivery.

Contrary to the above, during the Unit 2 EOC19 RFO in the fall of 2002, measures taken to evaluate the suitability of replacement parts were not adequate in that they did not preclude the installation of one non-conforming CRDM (Split Nut) Flange Ring on CRDM Assembly #18 on Unit 2. The same QA reviews of the remainder of the 68 CRDM (Split Nut) Flange Rings and 552 CRDM Hold Down Bolts in the warehouse did not identify the non-conforming parts prior to the attempt to install them on the Unit 3 reactor vessel head. Because the finding is of very low safety significance and because the issue is in the licensee’s corrective action program under PIPs O-03-2211, O-03-2132, O-03-2177 and O-03-2171, it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. Accordingly, it will be identified as NCV 05000270,287/2003003-07: Failure to Detect Non-Conforming Parts During Receipt Inspections.

D. <u>Radiation Protection</u>

a. <u>Inspection Scope</u>

Radiation safety controls for removal of the Unit 3 reactor vessel head and preparation of the head for temporary storage were reviewed and evaluated. Licensee procedures for posting, surveying, and controlling access to radiologically significant areas were assessed for adequacy. During tours of the Auxiliary Building and the Unit 3 Containment Building, the inspectors evaluated radiological postings and barricades against current radiological surveys and procedurally established radiological controls. Radiation Work Permits (RWPs) issued for the RVHRP were reviewed for incorporation of established access controls. RWP specified alarm setpoints for electronic dosimeters were also evaluated against current radiological surveys. Health Physics Technician (HPT) proficiency in providing job coverage and occupational workers’ adherence to RWP requirements were evaluated through worker interviews, work area tours and job site observations. The inspectors observed radiation dose rates measured by an HPT in the work areas adjacent to the vessel head after it was placed on the head stand. The observed work area dose rates were compared to the licensee’s most current documented survey results.

As Low As Reasonably Achievable (ALARA) planning and controls for the RVHRP were reviewed and evaluated for consistency with Section IV, ALARA Planning, of the licensee’s System ALARA Manual. ALARA Planning Worksheets, ALARA controls, dose estimates, dose tracking, exposure controls including temporary shielding, contamination and airborne radioactivity controls, project staffing and training, emergency contingencies, and temporary storage of the original reactor head assembly were reviewed and discussed with the licensee. RWPs issued for the RVHRP and their associated ALARA job briefing packages were examined for incorporation of the ALARA controls established for the project. Worker adherence to those controls was assessed through job site observations during the movement of original reactor head assembly to the head stand.

Through the above reviews and observations, the licensee's radiation safety program implementation and practices for the RVHRP were evaluated by the inspectors for consistency with 10 CFR 20 requirements and approved licensee procedures. Licensee plans, procedures, and records reviewed during the inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Institute of Nuclear Power Operations (INPO) Report Review

The inspectors reviewed the final report issued by INPO on April 28, 2003, for the evaluation that was conducted at the Oconee facility during the weeks of August 5, 2002, and August 12, 2002. The inspectors did not identify any safety issues in the INPO report that either warranted further NRC followup or that had not already been addressed by the NRC.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Ron Jones, Site Vice President, and other members of licensee management at the conclusion of the inspection on July 1, 2003. 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

4OA7 Licensee Identified Violation

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements, which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a NCV.

- TS Surveillance Requirement (SR) 3.4.12.5 specifies, in part, the required channel functional test frequency of the PORV to be within 12 hours after decreasing RCS temperature to less than or equal to 325 degrees F. On June 8, 2003, at 4:25 p.m., RCS temperature was lowered to less than 325 degrees F. On June 9, 2003, at 4:00 p.m., it was discovered that the channel functional test of the Unit 3 PORV had not been completed. The functional test was subsequently completed satisfactorily at 3:26 a.m., on June 10, 2003. The circumstances involving this missed surveillance are described in PIP O-03-03840. Because the subsequent performance of the missed TS SR was satisfactorily, this violation is of very low safety significance, and is being treated as a NCV.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Batson, Mechanical/Civil Engineering Manager
J. Batton, Oconee Steam Generator Engineer
D. Baxter, Engineering Manager
N. Constance, Operations Training Manager
C. Curry, Maintenance Manager
T. Curtis, Reactor & Electrical Systems Manager
D. Covar, Training Instructor
C. Eflin, Requalification Supervisor
W. Foster, Safety Assurance Manager
P. Fowler, Access Services Manager, Duke Power
T. Gillespie, Operations Manager
B. Hamilton, Station Manager
B. Jones, Training Manager
R. Jones, Site Vice President
T. King, Security Manager
B. Lowrey, Steam Generator Engineer
L. Nicholson, Regulatory Compliance Manager
R. Repko, Superintendent of Operations
J. Smith, Regulatory Affairs
J. Twiggs, Manager, Radiation Protection
J. Weast, Regulatory Compliance

NRC

L. Reyes, Regional Administrator, Region II
V. McCree, Deputy Director, Division of Reactor Projects, Region II
B. Haag, Chief, Branch 1, Division of Reactor Projects, Region II
C. Carpenter, Chief, Inspection Program Branch, NRR
L. Olshan, Project Manager

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000269,270,287/2003003-01	URI	Control Room Board Component Thermal Reliability (Section 1R02b.(1))
05000269,270,287/2003003-02	URI	HELB Accident Scenario Review (Section 1R02b.(2))

05000269,270,287/2003 003-03	URI	Failure to Implement Manufacturer's Recommendations for Replacement of SSF Diesel Coolant Grommets (Section 1R12.2)

Opened and Closed

05000269,270,287/2003 003-04	NCV	Failure to Identify the SSF Degraded Grommets as a Deficient Condition in the PIP Corrective Action Program (Section 1R12.2)
05000269/2003003-05	NCV	Failure to Maintain Sufficient Records (logs) to Furnish Evidence of Activities Affecting Quality (TS LCOs) (Section 1R14b.(1))
05000269/2003003-06	NCV	Failure to Declare ES Configured Components Inoperable per TS (Section 1R14b.(2))
05000270,287/2003003-07	NCV	Failure to Detect Non-Conforming Parts during Receipt Inspections (Section 40A5.1C)

Items Discussed

None

LIST OF DOCUMENTS REVIEWED

(Sections 1R02 and 1R17)

Screened Out Items

NSM 12995, Temporary Wiring Procedure
NSM 23092, 600 V MCC and Load Center
NSM 53065, UFSAR revision Section 9.5.1.4.3 Cable Splicing
ONOE- 10642, Upgrade Seismic Supports and Add Isolation Valve 3N-305 to Nitrogen Line
ONOE- 12107, Upgrade Discharge LPSW Piping from the MDEFDWPM coolers to 1LPSW-527 ONOE- 15414, Replace Valve 2LP-15 with Item DMV-1296 2A LPI Discharge to RBS Pump Spray and HPI Suction
ONOE- 12094, Modification of Unit 2 RC Vent system Supports/Restraints
ONOE- 12800 ,Provide Clearance Between the Valve Body of 2SF-101 and SSF RC Makeup Pump Discharge Piping

ONOE- 17011, Upgrade 3-CCW-269 to Meet EQ Requirements
ONOE-16856, Revise OSS-0254.00-00-1028
ONOE-16872, UST TAC Sheets
ONOE-16876, Revise Controlled Documents for RM-23A Module
ONOE-16990, Revise Test Acceptance Criteria Sheets for ECCW
ONOE-17068, Adjustable Trip Setting Correction for MCC's
NSM 23092, 600/208 VAC Load Capacity, Rev. 0
ONOE 11721, Include Alarm Setpoints of Stations Transformers in EDB and the OAC, 1
ONOE 14030, Modify Keowee Auxiliary Power Alignment Circuitry
ONOE 14409, Add fuses Between QA1 and Non-QA1 LPI Pump Circuits
ONOE 15256, Upgrade of Red Bus x/y Metering Transformers
ONOE-16712, Revise Maintenance Rule Design Basis Document to Add Reactor Building Ventilation Functions

Evaluations

NSM 33090, Voltage Adequacy Project NSM-ON-33090/AL3 (RBCU Three Minute Delay),
NSM-23053, Automatic Feedwater Isolation System
Calculation OSC-5325, ECCW Lake Level Verification
EP 3A 1800-01, Revision 39, Turbine Building Flooding [emergency operating porcedure]
NSM 13058, MSLB Leak Detection Circuitry
ONOE 15735, Removed ESF Signal to 3LP-21 and 22
UFSAR Section 3.11.5, Loss of Ventilation

PIPS

PIP O-99-0204
PIP O-91-0121
PIP O-96-0387
PIP O-00-1845
PIP O-98-3062
PIP O-98-2221
PIP-O-01-04635
PIP-O-02-02669
PIP-O-02-00619
PIP-O-02-00054

Audits

Assessment Report Number GO-02-01(NPA)(50.59)(ALL), Applicability Determination and 10 CFR 50.59 Process Evaluation, Assessment Dates 2/4/02 - 2/7/02
PIP-O-03-01300, Level II Assessment of Frametome ANP Compliance to Oconee Contractor Agreements, 2/18/03 - 2/18/03
PIP-O-03-01736, Level II Assessment 2MOD03001, Review of ONS Temporary Mod Process

Calculations

OSC-5267, Flow from UST to Hotwell - MSN-291
OSC-6901, Determination of Average Reactor Building Temperature (Type IV), Rev. 3
04158901-1SP, 12VDC Power Supply, SE P/N 50015966-001

Other Documents Reviewed
MARF #79

(Section 1R04)

Drawings

OFD-114A-1.4, Units 1 & 3 Flow Diagram of CC System (Drain Tank), Revision 5
OFD-144A-3.1, Unit 3 Flow Diagram of CC System (Supply and Return), Revision 7
OFD-144A-3.2, Unit 3 Flow Diagram of CC System (Reactor Building and Heat Exchangers), Revision 11
OFD-144A-3.3, Unit 3 Flow Diagram of CC System (Control Rod Drive Service Structure and Filters), Revision 6

Procedures

Selected Licensee Commitment 16.9.10, CC and HPI Seal Injection to Reactor Coolant Pumps (RCP)
AP/3/1700/014, Loss of Normal HPI Makeup and/or RCP Seal Injection
AP/3/1700/016, Abnormal Reactor Coolant Pump Operation
AP/3/1700/020, Loss of Component Cooling

UFSAR

Section 6.2.3, Containment Isolation System
Section 9.2.1, Component Cooling System

(Section 1R08)

Procedures

Framatome Technologies Procedure 54-ISI-400-11, Multifrequency Eddy Current Examination of Tubing, (with Procedure Qualification 54-PQ-400) and Change Notice 30-5027221-00 for Oconee Unit 3 EOC20 Requirements, dated April 22, 2003
Eddy Current Acquisition Guidelines for Duke Power Company's Once-Through Steam Generators (OTSG), Rev. 9, April 22, 2003
Data Management Guidelines, Rev. 0, April 23, 2003
Eddy Current Analysis Guidelines for Duke Power Company's Once-Through Steam Generators (OTSG), Rev. 6, April 22, 2003

Other Documents

Framatome ANP Engineering Information Record 51-5028238-00, In-Situ Pressure Test Summary for Oconee Unit 3 (May 2003)

Duke Power Steam Generator Management Program SGMEP 105, OTSG Specific Assessment of Potential Degradation Mechanisms for Oconee Unit 3 EOC 20, April 28, 2003

(Sections 40A5.1A-C)

Procedures

Procedure QEP 07.12-3,10CFR50.65(a)(4) Assessment
Procedure QEP 07-12, 10CFR50.59 Evaluations and 10CFR50.65 Assessments
NSD 403, Shutdown Risk Management (Modes 4, 5, 6, and No-Mode) per 10CFR 50.65 (a)(4), Rev. 11.
NSD 415, Operational Risk Management (Modes 1, 2, 3) per 10CFR 50.65 (a)(4), Rev. 1.
NSD 209, 10CFR50.59 Process, Rev. 9.
Mcinnes Steel Company Ultrasonic Test (UT) Procedure No. UT-SA388-95, Rev. 0
General Nuclear Corporation, Magnetic Particle Examination, Wet Continuous Method GNC-054, Rev. 1
Supply Chain Directive, SACD311, Rev. 1, “Receipt Inspection & Testing of QA Condition Items

Other Documents

Modification Package - RV Head Components Modification, Modification #33112, Part No. AM7, Rev. 0.
Reactor Vessel Closure Head Replacement Project, Oconee Nuclear Power Plant Units 1, 2, & 3, “Input Document for Replacement RVCHA Licensing and Safety Evaluation” April 2003.
Modification Package - Reactor Vessel Head Rigging and Handling, Modification # ON33112, Part No. AS1, Rev. 1.
Modification Package Review - Replacement of Reactor Vessel Closure Head, Service Structure and Associated Components, Modification # ON33112, Part No. 000, Rev. 0 (including 10CFR50.59 Screen).
Specification for Reactor Vessel for Duke Power Company, March 19, 1973
Oconee Unit 3, Rector Vessel Head Penetration Preservice Inspection, February 2003
Input Document for Replacement RVCHA Licensing and Safety Evaluation, April 2003
Oconee Unit 3 Reactor Vessel Head Penetration Preservice Inspection - February 2003, Final Report
Various site engineering drawings including Head Movement Drawings from Mammoet
Various FANP calcs and NCRs
Framatome ANP Document 32-5027297-00, Operability Assessment of CRDM Nut Ring with Reduced Tensile Strength Material
PIPs: O-03-2132, O-03-2211, O-03-2177, O-03-2171, O-03-2922, O-03-2998, O-03-2844, O-03-1218, O-03-2898
Framatome ANP NCRs: 6025753, 32-5027297-00, 6024468, 6024579, 6025325
Purchase Orders (POs): NS146-001, NS146-002, ON52461, ON13513
Receipt Inspection Reports for: PO NS146-001, PO NS146-002, PO ON52461, PO ON13513
Corrective Action Reports (CARs): 6025777-00

(Section 40A5.1D)

Procedures, Plans, and Manuals

Standard Health Physics Procedure (SH) SH/0/B/2000/005, Posting of Radiation Control Zones, Revision (Rev.) 1
SH/0/B/2000/012, Access Controls for High, Extra High, and Very High Radiation Areas, Rev. 1
Duke Power Company System ALARA Manual, Section IV, ALARA Planning, Rev. 15, 10/15/02
Radiation Protection (RP) Job Coverage Plan, Rev. 1, 4/9/03
RP-012, Surveillance Plan, Rev. 0, 4/15/03

Records

ALARA Planning Worksheet - Unit 3 Reactor Head Replacement - Install and Remove Scaffolding (Equipment Chase Area and Reactor Head Stand)
ALARA Planning Worksheet - Unit 3 RHRP Install Shielding, Encapsulate Reactor Head and Decon Activities
ALARA Planning Worksheet - Unit 3 Reactor Head Replacement - Remove and Install Interferences in Equipment Chase Area
ALARA Planning Worksheet - Unit 3 Reactor Head Replacemant - Electrical/Mechanical Disconnects and Reconnects, Remove/Install Interferences, CRD Remmoval
ALARA Planning Worksheet - Unit 3 Reactor Head Replacement - Install and Remove Lifting Equipment, Remove ORVH and Install RRVH
Radiation Survey Report 050603-30, Reactor Vessel Head, 5/6/03
Radiation Survey Report 050703-1, Reactor Vessel Head, 5/6/03
ALARA Briefing Packages for Radiation Work Permits 6375, 6376, 6377, 6378, 6379, and 6380
Daily Exposure reports for 5/6 & 7/03

Radiation Work Permits (RWPs)

RWP 6375, U3 Rx Bldg - RHRP - Install and Remove Scaffolding, Rev. 0, 02/06/03
RWP 6376, U3 Rx Bldg - RHRP - Install Shielding, Encapsulate Rx Head, and Decon Activities, Rev. 0, 02/06/03
RWP 6377, U3 Rx Bldg - RHRP - Remove and Install Interferences in the Equipment Chase Area, Rev. 0, 02/06/03
RWP 6378, U3 Rx Bldg - RHRP - Remove and Install Rx Head Interferrences, Piping, and all CRDM Work, Rev. 0, 02/06/03
RWP 6379, U3 Rx Bldg - RHRP - Install and Remove Lifting Equipment, Remove Original Reactor Head Assembly (RHA) and Install Replacement RHA, Rev. 0, 02/06/03
RWP 6380, U3 Rx Bldg - RHRP - Load, Transport and Store Original RHA, Incluses All Outside Work, Rev. 0, 02/06/03

LIST OF ACRONYMS

ADAMS	-	Agencywide Documents Access and Management System
ALARA	-	As Low As Reasonably Achievable
ASME	-	American Society of Mechanical Engineers
BCM	-	Boiler/Condenser Mode
BWST	-	Borated Water Storage Tanks
CC	-	Component Cooling
CFR	-	Code of Federal Regulations
COLR	-	Core Operating Limits Report
CRDM	-	Control Rod Drive Mechanism
DEC	-	Duke Energy Corporation
DPC	-	Duke Power Company
EFW	-	Emergency Feedwater
EHC	-	Electro-Hydraulic Control
EOC	-	End of Cycle
ES	-	Engineered Safeguards
ESI	-	Engine Systems, Inc
ET	-	Eddy Current Testing
FSAR	-	Final Safety Analysis Report
HELB	-	High Energy Line Break
HPI	-	High Pressure Injection
HPT	-	Health Physics Technician
INPO	-	Institute of Nuclear Power Operations
IR	-	Inspection Report
IST	-	Inservice Testing
LBLOCA	-	Large Break Loss of Coolant Accident
LCO	-	Limiting Condition for Operation
LLRT	-	Local Leak Rate Test
LPI	-	Low Pressure Injection
LPSW	-	Low Pressure Service Water
NCV	-	Non-Cited Violation
NDE	-	Non-Destructive Examination
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
NSM	-	Nuclear Station Modification
OFD	-	Oconee Flow Diagram
ONOE	-	Minor Modification
ONS	-	Oconee Nuclear Station
OTSG	-	Once-Through Steam Generator
PI	-	Performance Indicators
PIP	-	Problem Investigation Process (report)
PT	-	Performance Test
PMT	-	Post-Maintenance Testing
PORV	-	Power Operated Relief Valve
QA	-	Quality Assurance
QC	-	Quality Control
RBCU	-	Reactor Building Cooling Unit
RBS	-	Reactor Building Spray

RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RFO	-	Refueling Outage
RTP	-	Rated Thermal Power
RVHRP	-	Reactor Vessel Head Replacement Project
RWP	-	Radiation Work Permit
SBLOCA	-	Small Break Loss of Coolant Accident
SDP	-	Significance Determination Process
SG	-	Steam Generator
SR	-	Surveillance Requirement
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
UT	-	Ultrasonic Testing