U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7812B Rochester Highway Seneca, SC 29672
Dates:	January 17, 1999 - February 27, 1999
Inspectors:	M. Scott, Senior Resident Inspector S. Freeman, Resident Inspector E. Christnot, Resident Inspector D. Billings, Resident Inspector R. Chou, Reactor Inspector (Section M1.6) C. Smith, Reactor Inspector (Section E7.2) E. Girard, Reactor Inspector (Sections M8.4, E7.1, E8.1) F. Jape, Senior Project Manager (Sections O8.2, O8.3, M8.2, M8.3, E8.2)
Approved by:	C. Ogle, Chief, Projects Branch 1 Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2, and 3
NRC Inspection Report 50-269/99-01,
50-270/99-01, and 50-287/99-01

This integrated inspection included aspects of licensee operations, maintenance and engineering. The report covers a six-week period of resident inspection, as well as the results of announced regional based inspections.

Operations

- The licensee has met their operations procedure development and quality improvement item goals and measures under the Recovery Plan. Implementation of procedure enhancements was adequate based on the goal being met **(Recovery Plan Item OF2 - closed)**. (Section O4.1; [POS: 1C])

- An increased effort towards in-depth and critical examinations by the licensee in the assessment area was adequate to demonstrate improvement in the licensee's safety assessment processes **(Recovery Plan Item NRC2 - closed)**. (Section O7.1; [POS: 5A, 5B, 5C])

- The Keowee frequency overshoot reduction and load rejection tests were well written, technically correct, properly reviewed, and properly performed. (Section O8.1; [POS: 4B, 4C])

Maintenance

- Management's decision to change out the actuator on valve 1HP-27 due to a degrading trend (prior to actual failure) was conservative. This indicated proper concern for degrading equipment trends. (Section M1.2; [POS: 2B, 4B])

- The work to change out the 1HP-27 valve actuator was well planned with good communications between operations and maintenance and completed well before the expiration of the Technical Specification limiting condition for operation. (Section M1.2; [POS: 3A])

- Omission of a routinely performed post-maintenance trending/adjustment of the Keowee Hydro Unit air operated circuit breaker pressure regulators is considered to be a weakness. (Section M1.3; [NEG: 2B])

- The licensee has adequately completed or scheduled Recovery Plan activities regarding material condition and housekeeping **(Recovery Plan Item SE1 - closed)**. (Section M1.4; [POS: 2A])

- Mechanical and instrumentation troubleshooting procedures met the intent of the Recovery Plan **(Recovery Plan Item TD5 - closed).** (Section M1.5; [POS: 2B])

- The procedures used for the spent fuel dry cask and related activities were adequate to provide the details for craft personnel to conduct work. The licensee resolved the problems encountered. (Section M1.6; [POS: 3C, 3A])

- The fire brigade response and followup actions to isolate the area and use additional safety personnel for the blowdown of the hydrogen tank were excellent. (Section M2.1; [POS: 1C, 3A, 3B])

- The maintenance and engineering followup to analyze and resolve future problems with the hydrogen rupture discs by the installation of minor modifications to prevent water intrusion was good. (Section M2.1; [POS: 2B, 4B, 5C])

- The lack of recognition of industry events concerning hydrogen tank rupture disc failures, reflected a potential weakness in the licensee's Operating Experience Feedback Program. (Section M2.1; [NEG: 4C])

- Pressurizer heater requirements for standby shutdown facility operability were not clearly documented in the Updated Final Safety Analysis Report, Technical Specifications (TS), Improved TS, and plant procedures. (Section M3.1; [NEG: 2B, 4A])

- The inspectors identified a non-cited violation for failure to follow material control procedures when obtaining spare parts for use on the station auxiliary service water pump. This failure resulted from a lack of knowledge of the parts specification process. (Section M8.1; [NCV: 3A, 3B])

- The inspectors identified a non-cited violation for failure to require motor operated valve (MOV) stroke time measurements in both directions for MOVs with active safety functions in both the open and closed directions. (Section M8.4; [NCV: 2B])

Engineering

- The engineering evaluation of the problems with the Keowee air circuit breakers demonstrated a good safety assessment attitude and adequate technical support **(Recovery Plan Item NRC2)**. (Section E2.1; [POS: 4B])

- The licensee satisfactorily established the cause, evaluated the current and past operability, and provided appropriately conservative corrective actions for difficulties experienced in opening emergency feedwater crossover valves FDW-313 and -314. Overall, the licensee's resolution of the difficulties experienced in opening the emergency feedwater crossover valves was considered good. (Section E7.1; [POS: 5B, 5C])

- An unresolved item was identified regarding the licensee's designation of maintenance rule function EFW.3, "provide backup emergency feedwater to other Oconee units," as not risk significant. (Section E7.1; [URI: 4A, 4B])

- Near term corrective actions developed for configuration management deficiencies were poorly implemented. Changes to Section 4.0 of the Configuration Management Improvement Team Charter were not evaluated for effect on interim resolutions, nor the effectiveness of recurrence controls to be implemented by long-term corrective actions **(Recovery Plan Item D10)**. (Section E7.2; [NEG: 4C, 5C])

- The inspectors identified a non-cited violation concerning three examples of failure to meet the requirements of 10 CFR 50, Appendix B, Criterion XVI. (Section E8.1; [NCV: 4B, 5C])

Report Details

Summary of Plant Status

Unit 1 began and ended the period at 100 percent power.

Unit 2 began the reporting period at 100 percent power. The unit was shutdown on February 23, 1999, to repair leaking feedwater risers on the steam generators. Following repairs, the unit went critical on February 26, 1999, and returned to 100 percent power on February 27, 1999, the last day of the reporting period.

Unit 3 began and ended the period at 100 percent power.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure (IP) 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O2 Operational Status of Facilities and Equipment

O2.1 Operations Clearances (71707)

The inspectors reviewed the following clearances during the inspection period:

- 98-4817 Keowee Unit 1 Governor Maintenance
- 99-0057 Replace Valve 3 SSW - 151
- 99-0168 Unit 1 High Pressure Injection Pump
- 99-0098 Unit 1 and 2 Spare Component Cooling Heat Exchanger
- 98-5139 3B LPSW Pump Oil Leak

The inspectors observed that the clearances were properly prepared and authorized, and the tagged components were in the required positions with the appropriate tags in place.

The inspectors also reviewed the following clearance that was no longer in effect during the inspection period:

- 99-0095 3B LPI Pump

The inspectors observed that the equipment was returned to service appropriately and that the tags were removed.

O2.2 Containment Isolation Lineup (71707)

The inspectors reviewed the following portion of the containment isolation lineup during the inspection period:

- Unit 3 East Penetration Room

The inspectors observed that portions of the lineup reviewed were in accordance with plant operating procedures and the Updated Final Safety Analysis Report (UFSAR).

O2.3 Detailed Engineered Safety System Walkdown (71707)

The inspectors performed a detailed walk down of the Keowee Hydro-Electric units (KHUs) air circuit breakers (ACB) and air supply systems. This included observations of normally inaccessible portions of the systems during maintenance activities and inside breaker cabinets during operator rounds. The inspectors reviewed the piping drawings, electrical logic drawings, and vendor manual for the systems and found the valves and instruments to be as shown on the documents. The inspectors also found material condition and housekeeping to be acceptable in all cases. The inspectors identified no substantive concerns as a result of these walkdowns. The inspectors also reviewed the UFSAR and Design Basis Document (DBD). Findings for this review are discussed in Sections M1.3 and E2.1.

O4 Operator Knowledge and Performance

O4.1 Technical Quality of Operating Procedures (Recovery Plan Item OF2)

a. Scope of Inspection (71707)

The inspectors reviewed multiple operations procedures and interviewed operations department personnel. This review was to assess procedures on-hold, outstanding revisions, and conversion to the new word processing software in accordance with Recovery Plan initiatives.

b. Observation and Findings

The milestones and measures listed in the licensee's Recovery Plan for the subject item have been completed. The inspectors reviewed the new procedures for format, uniformity, and readability. The inspectors verified procedures on hold were not available in controlled issue files and that the total number was low. The inspectors found a discrepancy in the operations data base that listed a procedure as being on hold that was found in the Unit 1 and 2 control files. The inspectors verified that the data base was in error and this error was corrected by the licensee. Of the procedures sampled, the inspectors verified that the procedures had been reviewed by a qualified reviewer prior to its re-issue. The licensee stated that all operations procedures had been through the enhancement revision process and qualified reviewer process prior to issue. The inspectors verified that 253 procedures were awaiting enhancement, less than the licensee's goal of 300. The inspectors also checked that the number of procedures to be re-issued with greater than five proposed changes was low and found there were four procedures in this category. Three were sections of the emergency operating procedures (EOPs) that have existing page changes that will be rolled into a complete document revision. A total EOP revision was planned in the future as the Integrated Technical Specification review is completed.

The plant issues matrix (PIM) data base and the licensee's corrective action (CA) program contained few procedure related problems for this period. The new procedures used to date have not created significant problems.

c. Conclusions

The licensee has met their operations procedure development and quality improvement item goals and measures under the Recovery Plan. Implementation of procedure enhancements was adequate based on the goal being met. Recovery Plan Item OF2 is closed.

O6 Operations Organization and Administration

O6.1 Institute Of Nuclear Power Organization (INPO) Report Review (71707)

During the inspection period, the inspectors reviewed the INPO report dated December 10, 1998. The final report was not available to the NRC until February 1999. The inspectors determined that the results of the INPO evaluations were generally consistent with the results of inspection conducted by the NRC. No new items for followup were identified.

O7 Quality Assurance in Operations

O7.1 Safety Assessments for Plant Operations and Support of Operations (Recovery Plan Item NRC2)

a. Inspection Scope (71707, 62707, 71750, 37751)

The inspectors reviewed the safety assessment activities in the areas of operations, maintenance, engineering, and plant support. This is identified as item NRC2 in the Recovery Plan. That portion of item NRC2 concerning risk assessment, was previously reviewed and closed in Inspection Report (IR) 50-269,270,287/98-11 (Section O2.5).

b. Observations and Findings

The inspectors reviewed safety assessment activities in quality assurance (QA), the problem identification process (PIP), the failure identification process (FIP), self-initiated technical reviews, self-assessments, and outage critiques. The review indicated an in-depth and critical examination effort by the licensee in the assessment areas. The outage critiques indicated areas needing improvement. The reactor protection assessment indicated problems identified by internal and external licensee inspections and audits. The assessments discussed improvements and techniques used recently during outages and those proposed for the next unit outage. Examples of a proper safety assessment were discussed in IR 50-269,270,287/98-09 and 07 (Sections E2.2 and E2.1, respectively), and in Section E2.1 of this report. Overall, the documents reviewed were adequate to demonstrate improvement in the licensee's safety assessment processes.

c. Conclusions

An increased effort towards in-depth and critical examinations by the licensee in the assessment area was adequate to demonstrate improvement in the licensee's safety assessment processes. Recovery Plan Item NRC2 is closed.

O8 Miscellaneous Operations Issues (92901, 92700)

O8.1 (Closed) Inspector Followup Item (IFI) 50-269,270,287/98-11-01: Keowee Commercial Operation to Emergency Start Evaluation

This IFI was opened when the Keowee Hydroelectric Units (KHUs) were operated commercially outside the lake levels specified in the selected licensee commitments (SLC). The licensee initially discontinued commercial operation of the KHUs until they could obtain more data for lake level restrictions.

The licensee performed two tests, which temporarily modified the controls for the KHU-2 governor during an emergency start to determine if the frequency overshoot could be reduced and collect data during load rejection for turbine performance calculations. The results of the tests showed that overshoot was reduced and that both KHUs, with or without the modifications, returned to design frequency within the design limit. The inspectors concurred that the licensee's evaluation, which was discussed in IR 50-269,270,287/98-11 (Section O1.5.b(2)), was consistent with the results of these two tests of KHU governor overshoot control. Based on the test results, the licensee imposed a higher minimum lake level for commercial operation until new SLC "static" level curves can be developed.

The inspectors reviewed associated test Procedures TT/0/0620/039, Keowee Overshoot Reduction Test, Revision 0, and TT/0/A/0620/040, Keowee Hydro Load Rejection Test, Revision 1, as well as observed test performance. The tests were well written, technically correct, properly reviewed, and properly performed. This IFI is closed.

O8.2 (Closed) Violation (VIO) 50-270,287/97-01-03: Failure to Follow Valve Procedure

(Closed) Licensee Event Report (LER) 50-270/96-007 (Revisions 0 - 2): Low Pressure Injection (LPI) System Technically Inoperable For Appendix R Scenario Due To Inadequate Work Practices

The violation was previously discussed in NRC IR 50-269,270,287/98-11. The LER is related to the same issue. The violation and the LER remained open pending resolution of Corrective Action 3.c, as presented in the licensee response and Revision 00 of the LER. LER Revision 02, issued January 22, 1999, revised the planned corrective action and Item 3.c has been resolved. Basically, the wiring configuration has been verified to match the as-built design documents. In Revision 02 of the LER, the licensee determined that additional testing would not provide any more assurance of the current wiring configuration. All other corrective actions have been completed. The violation and LER revisions are closed.

O8.3 (Closed) VIO 50-269,270/98-02-04: Failure to Follow Procedure for Foreign Material Control

The inspectors verified completion of the corrective actions described in the licensee's response, dated May 20, 1998, to this violation. Signs have been posted at each entrance to the spent fuel pool denoting the cleanliness zone and the foreign material exclusion (FME) requirements. Procedure OP/0/A/1510/16, Miscellaneous Spent Fuel Pool/Canal Operations, Revision 4, states in part that the requirements of Nuclear Site Directive (NSD) 104, Housekeeping Material Condition and Foreign Material Exclusion, Revision 18, shall be followed for all activities performed under this procedure. The procedures now require a person to be assigned to the FME logging function. The other corrective actions described in the response were also verified as completed. This violation is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707, 61726)

The inspectors observed all or portions of the following maintenance activities:

- WO 98123489 — Change Unit 3 Electro-hydraulic System Fullers Earth Filters
- WO 98124105 — Change Electro-hydraulic System Recirculation Fine Filter
- WO 98126654 — 1HP-27 Perform Diagnostic Test
- PT/1/A/0152/011 — HPI Valve Stroke Test, Enclosure 13.1 HPI Valves Stroked on a Quarterly Frequency, Revision 1
- PT/2/A/0150/22L — TDEFW Pump Backup Cooling Water Supply Test, Revision 19
- WO 98124124 — OE-13184, Assist Vendor with Replacement of Hydrogen Tank Rupture Disc and Valves
- WO 98007290 — Relocate Keowee Unit 1 Thrust Bearing Cooling and Unit Cooling Return Water Flow Switches
- MP/1/A/2000/03 — Keowee Unit 1 Governor Actuator Inspection, Revision 4
- IP/0/A/3010/3A — Mounting Field Run Instrument Tubing and Cable Support Systems, Revision 6
- IP/0/A/5090/01 — Tube Fitting and Tubing Installation, Revision 5
- MP/1/A/2200/06 — Inspection and Maintenance of Keowee Unit 1 PMG, Revision 5
- WO 98064967 — Implement Keowee Minor Modification ONOE-8761
- OP/0/A/0610/41 — Keowee Modes of Operation, Revision 6
- WO 98077769 — Replace Unit 3 Syphon Service Water Valve 151 - Direct Replacement
- IP/0/A/2005/03 — Keowee Hydro Station Voltage Regulator Test, Revision 26

- PT/2/A/0203/6A — 2B Low Pressure Injection Pump Test - Re-circulation, Revision 52
- PT/2/A/0152/13 — Unit 2 LPSW System Valve Stroke Test, Revision 7
- WO 98132132 — Replace 1ACB-3, Keowee Unit Pressure Regulator
- WR 98066768 — PCB 19 Gas Pressurization
- WO 98121228 — U3 ES Digital Channel 3 Online Test
- WO 98115020 — I/R 3B LPSW Pump Oil Leak O/B

b. Observations and Findings

In general, the inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in use. Technicians were experienced and knowledgeable of their assigned tasks. Quality control personnel were present when required by procedure. When applicable, radiation control measures were in place.

c. Conclusions

The inspectors concluded that the maintenance activities listed above were completed thoroughly and professionally.

M1.2 Valve 1HP-27 Actuator Degradation

a. Inspection Scope (62707, 37551)

The inspectors observed maintenance activities, reviewed valve data, and interviewed personnel dealing with the degradation of the 1HP-27 valve actuator.

b. Observations and Findings

On February 14, 1998, during engineered safeguards (ES) performance testing on Unit 1, motor operated high pressure injection (HPI) valve 1HP-27 failed to close properly. The licensee commenced quarterly motor power monitoring (MPM) testing on the valve as part of the corrective actions from this event (IR 50-269,270,287/98-02, Section E1.1).

During valve MPM testing in September and December 1998, a trend of increased time and torque values were identified on 1HP-27. Engineering analysis indicated actuator degradation, but there was sufficient margin to declare the valve operable. The inspectors reviewed the data. Engineering requested additional valve stroke data to evaluate long-term operability. The inspectors observed diagnostic and MPM testing on January 28, 1999, and reviewed the data. Licensee management decided to change out the actuator on 1HP-27 following discussions with engineering. The licensee entered a 24-hour Technical Specification (TS) limiting condition for operation (LCO) on January 29, 1999, at 11:49 a.m. to replace the actuator. The licensee completed the change out and testing of 1HP-27 at 12:15 a.m. on January 30, 1999, and exited the LCO.

The inspectors observed the removal of the old actuator and verified the work area was returned to an acceptable level of material cleanliness. The old actuator was taken to the machine shop for additional inspection. Radiation worker support was adequate.

The inspectors observed portions of the disassembly and inspection of the actuator assembly. The inspectors noted that no obvious mechanism for the degradation of the actuator had been identified. The worm gear assembly did indicate some heat generation and traces of brass deposits.

1HP-26 has been tested and has shown no degradation with the same type of actuator. Unit 2 and 3 valves, 2/3HP-26 and 2/3HP-27 have been replaced with the larger SB actuator. 1HP-26 and 1HP-27 will be replaced with the larger SB actuator during the next Unit 1 refueling outage.

c. Conclusions

Management's decision to change out the actuator on valve 1HP-27 due to a degrading trend (prior to actual failure) was conservative. This indicated proper concern for degrading equipment trends.

The work to change out the 1HP-27 valve actuator was well planned with good communications between operations and maintenance, and was completed well before expiration of the TS LCO.

M1.3 Keowee Air System

a. Scope (62707, 71707)

On February 2, 1999, the KHUs experienced a series of low air pressure alarms on the air supply system for the ACBs. The inspectors interviewed personnel and observed the maintenance activities on the ACBs.

b. Observations and Findings

On December 10, 1998, the licensee opened the cross-connect valve between the KHU-1 and KHU-2 ACB air systems due to slow response of the KHU-1 air regulator. On January 28, 1999, maintenance personnel performed routine preventive maintenance on the KHU-2 air regulator with the cross-connect valve still open. On February 1, 1999, maintenance performed the same preventive maintenance on the KHU-1 air regulator. Approximately eleven hours later, Keowee operators received low air pressure alarms for KHU-1. As part of the alarm response, the operators closed the cross-connect valve. Low air pressure alarms for KHU-2 were received a short time later. The Keowee operators responded promptly by requesting maintenance followup. Maintenance verified the alarms and reset the air regulators to maintain the system pressure. The licensee initiated PIP K-O99-0392 for tracking and followup.

The inspectors reviewed the Keowee logs, work order history, and discussed maintenance with the personnel involved. The inspectors determined that, by practice, after returning the air system to service the regulators were normally monitored and adjusted over about six hours. This allowed the regulator to be adjusted to the required 160 pounds per square inch gauge (psig) based on the post-adjustment trends in pressure. The inspector's review of Procedure IP/O/A/2001/01, Inspection and Maintenance of the Air Circuit Breaker Air Supply System, Revision 7, indicated that this was not a procedure requirement. The operator logs indicated that the KHU-1 system was returned to service at 3:40 p.m., on February 1, 1999. No arrangements were made to have Keowee operators check for air pressure decay over the next several hours. Adjustments were not made until February 2, 1999, after the initial alarm on KHU-1. The lowest pressures recorded were 147 psig on ACB-3 in the KHU-1 air system and 142 psig on ACB-4 in the KHU-2 air system. The inspectors determined that the KHUs had not been out of service or inoperable during the low pressure condition. The maintenance personnel planned to incorporate the practice of checking the pressures for trending over a six hour period. The engineering aspects of this occurrence are in Section E2.1 of this report.

c. Conclusions

Omission of a routinely performed post-maintenance trending/adjustment of the Keowee Hydro Unit air operated circuit breaker pressure regulators is considered to be a weakness.

M1.4 Material Condition (Recovery Plan Item SE1)

a. Inspection Scope

The inspectors reviewed goals and measures, observed areas in the plant, and interviewed personnel involved with material condition (matcon) Recovery Plan Item SE1. This was previously discussed in IR 50-269,270,287/98-11, Section M1.4.

b. Observations and Findings

The license has completed or scheduled all the matcon measures and actions listed in the Recovery Plan. Matcon is the process to paint/preserve the equipment and reduce equipment problems. During inspection tours, the inspectors have observed adequate completion of scheduled matcon work. The licensee has scheduled and funded further matcon work and has begun renewed refurbishment activity in the main turbine building.

c. Conclusion

The licensee has adequately completed or scheduled the material condition and housekeeping activities described in the Recovery Plan. Recovery Plan Item SE1 is closed.

M1.5 Improved Troubleshooting (Recovery Plan Item TD5)

a. Inspection Scope (62707)

The inspectors reviewed the procedures and observed performance of activities covered by the Improved Troubleshooting Temporary Defense.

b. Observations and Findings

The inspectors reviewed the licensee's two troubleshooting procedures in IR 50-269,270,287/98-11 (Section M1.3) and determined they met the intent of the Recovery Plan. The inspectors further reviewed the procedures during this inspection period to check the differences between the procedures. The inspectors determined that existing differences were of a minor nature and that the procedures still met the intent of the Recovery Plan.

The inspectors observed performance of maintenance crews using Procedure MP/0/A/1800/022, Controlling Procedure for Troubleshooting and Corrective Maintenance, Revision 15. In all cases, the crew implemented the risk assessment, troubleshooting plans, and corrective action plans according to procedure.

c. Conclusions

Mechanical and instrumentation troubleshooting procedures met the intent of the Recovery Plan. Recovery Plan Item TD5 is closed.

M1.6 Observation of Dry Cask for Units 1 and 2

a. Inspection Scope (60855)

The inspectors observed portions of spent fuel cask welding, monitoring, and inspection activities to verify that the activities were performed in accordance with the applicable procedures and work orders.

b. Observations and Findings

Activities observed included setup and welding of the automatic welding machine for the inner top cover plate, monitoring of the hydrogen concentration inside the cask during the welding, the quality control (QC) inspection on the first (root) pass of welding for the inner top cover plate, and welding for the vent and siphon ports of the cask.

The procedures used/reviewed were as follows:

- MP/O/A/1500/016, Independent Spent Fuel Storage Installation Phase III Dry Storage Canister Loading and Storage, Revisions 3, 4, and 5
- MP/O/A/1810/019, Cask-NUHOMS 24P Dry Storage Canister-Welding, Revision 10

The inspector reviewed the required records and data contained in the working copy of the procedure. The inspector also reviewed records for crane operator qualification, crane maintenance, and crane inspection. The inspector determined that the licensee performed adequately with respect to welding and hydrogen concentration monitoring problems which occurred.

c. Conclusion

The procedures used for the spent fuel dry cask and related activities were adequate to provide the details for craft personnel to conduct work. The licensee resolved the problems encountered.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Hydrogen Tank Blow Down Due to Rupture Disc Failure

a. Inspection Scope (62707, 71707)

The inspectors observed operations and maintenance activities associated with the blow down, investigation, and repair of the C hydrogen tank. This was initially discussed in IR 50-269,270,287/98-11 (Section M1.2).

b. Observations and Findings

On January 5, 1999, security personnel detected a loud noise and the sound of escaping gas under pressure from the vicinity of the bulk hydrogen cage. Operations was notified and the fire brigade responded in full gear and with extra personnel from the safety department. The area was roped off and traffic was diverted from that side of the station. The fire brigade investigated and determined that the C hydrogen tank was depressurized and no fire had been present.

The inspectors observed maintenance and vendor followup investigation. This followup revealed that a rupture disc on the tank had failed due to the freezing of water that had intruded into the tank rupture disk vertical tail pipe. The licensee contacted the vendor to repair and check all six of the tanks. The licensee subsequently installed a modification to route the discharge pipe through the roof of the cage area and to install a newer vendor supplied rupture disc assembly. This included a cap on the discharge pipe and a plastic diaphragm above the rupture disc to prevent any water intrusion on the rupture disc. The original vendor configuration and tail pipe cap did not prevent water entry.

Followup discussions with the licensee revealed that similar events had been identified at other utilities. The inspectors concluded that the lack of recognition of this industry problem reflected a potential weakness in the licensee's Operating Experience Feedback Program.

c. Conclusions

The fire brigade response and followup actions to isolate the area and use additional safety personnel for the blowdown of the hydrogen tank were excellent.

The maintenance and engineering followup to analyze and resolve future problems with the hydrogen rupture discs by the installation of minor modifications to prevent water intrusion was good.

The lack of recognition of industry events concerning hydrogen tank rupture disc failures, reflected a potential weakness in the licensee's Operating Experience Feedback Program.

M3 Maintenance Procedures and Documentation

M3.1 Pressurizer Heater Requirements and Surveillance

a. Inspection Scope (62707)

The inspectors reviewed the UFSAR, DBDs, maintenance work orders, and interviewed operations and maintenance personnel on the requirements for pressurizer (PZR) heaters.

b. Observations and Findings

On January 25, 1999, the standby shutdown facility (SSF) was declared inoperable for Unit 2 as a result of a ground detected on the pressurizer heaters powered from the SSF. Unit 2 entered TS 3.18, a 72-hour LCO. The available number of PZR heaters for Unit 2 which could be powered from the SSF was less than the required 5 elements as a result of the electrical ground fault. Instrument and Electrical Department (I&E) personnel investigated and found one bad heater element. The associated breaker was opened and the ground fault cleared. This resulted in 6 of 9 heater elements being operable, since the heaters are controlled in groups of three from a single breaker for each group. Operations declared the SSF operable for Unit 2 and exited the LCO.

The inspectors reviewed documentation to verify the PZR heater requirements. Documentation regarding the number of PZR heaters was vague. The current TS did not contain a requirement for PZR heaters. The only requirement was found in Operations Management Procedure (OMP) 2-7, SSF LCO Required Actions, Revision 9. The OMP required 5 of the 9 PZR heater elements on bank 2B to be operable to ensure operability of the SSF per unit. The ITS contains a requirement for 126 kilowatts (KW) of PZR heaters to be operable per unit. The ITS basis does not describe whether these heaters were required for normal or SSF type situations.

The UFSAR states that 107 KW of heaters are needed per a generic Babcock & Wilcox analysis to make up for ambient losses from the PZR during a natural circulation event. This was previously identified in IR 50-269,270,287/88-17. A calculation, OSC-3144, completed by Duke Energy showed the required amount of PZR heaters needed for the Oconee units to be 70 KW. This calculation was reviewed in IR 50-269,270,287/88-32 and found to be acceptable. Further, The UFSAR states that the commitment is to maintain 126 KW, the total of the smallest bundle, for an SSF event where natural circulation cooling would be required. The inspectors questioned the differences in required heater capacity in the UFSAR, the calculation, the B&W calculation, and the ITS.

The inspectors also questioned maintenance personnel on the mechanism of checking the heaters for operability. I&E personnel were using a Work Order (WO) to check amperage readings on the 2B PZR heater bank to determine actual kilowatt availability. There was no requirement to have a formal procedure to verify PZR heaters. Licensee management determined that the process was too informal and has decided to initiate a formal procedure.

The licensee stated that they would review and revise the UFSAR as necessary. This review was to ensure the checks of the PZR heaters were properly included in procedures and that they reflected non-conflicting KW requirements. This was documented in PIPs 2-O99-0268, 0-O99-0296, and 0-O99-0405.

c. Conclusions

Pressurizer heater requirements for SSF operability were not clearly documented in the UFSAR, TS, ITS, and plant procedures.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Unresolved Item (URI) 50-269,270,287/98-08-01: Configuration Control of the Station Auxiliary Service Water (ASW) Pump

This item was opened for NRC review of procedures, material controls, and work control requirements on the station ASW pump after the inspectors observed several problems with the pump packing during impeller replacement in September 1998. The inspectors reviewed the procedure for repair and replacement of the station ASW pump rotating assembly and the procedure for installing and adjusting pump packing. The inspectors determined that these procedures were adequate for the job discussed in this URI.

The inspectors reviewed the circumstances surrounding the impeller replacement in September 1998 to determine the material controls for the parts used on the ASW pump and the work control requirements for a change in job scope. While changing the impeller, licensee personnel decided that the packing follower nuts should be changed. They further decided that the existing package was adequate to perform the work and chose not to replan the work order nor make changes to the existing printed package. Work Process Manual, Revision 5, Section 700.5.3.4.3, discussed changes to work scope and required that if a problem was discovered that changed or increased the original scope of work, the work must stop and the work order task replanned or a new task created. This section also stated that changes to scope that did not affect the original intent of the work order task could be made on the printed task package with the work management system to be updated before the end of the shift. Neither of these steps was accomplished when the packing follower nuts were replaced. The failure to do so constitutes a violation of minor significance and is not subject to formal enforcement action.

To locate new nuts for the packing follower, maintenance personnel checked the parts list in the work management system and found the nuts were not listed. They also checked the vendor manual, which they felt was unclear on the type of nuts. Maintenance personnel then checked the piping specification for material requirements and used the nuts specified for the class of piping listed on the ASW system flow diagram. Nuclear Generation Maintenance Manual, Revision 3, Appendix A, described the responsibilities for determining correct QA parts and material. Section A.5 stated that technical support and planning personnel were responsible for specifying parts by using controlled documents. If controlled documents did not exist or there was a discrepancy, personnel were to contact engineering and use other approved processes such as PIP, modification, or acceptable substitute request. The inspectors reviewed the ASW system flow diagram and piping specification and determined that the specification only applied to piping and not components. The inspectors therefore determined that maintenance personnel did not specify parts for the station ASW pump in accordance with the Nuclear Generation Maintenance Manual. This is a violation of 10CFR50, Appendix B, Criterion V, and appeared to result from personnel not understanding that the material control appendix to the Nuclear Generation Maintenance Manual was available for use. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Appendix C of the NRC Enforcement Policy and is identified as NCV 50-269,270,287/99-01-01, Failure to Follow Procedure for Obtaining Spare Parts. This violation is in the licensee's corrective action program as PIP 1-O98-4212.

A subsequent engineering analysis was performed which demonstrated that the nuts used were acceptable. The licensee has plans to install the proper nuts.

M8.2 (Closed) VIO 50-269/98-01-02: Maintenance Procedure MP/0/A/1810/014 Provided Inadequate Instructions for the Use of Purge Paper as Weld Damming Material

The corrective actions provided in the licensee's response dated April 17, 1998, were verified as completed. Maintenance procedures MP/0/A/1810/014, Valves-and Piping-Welded-Removal and Replacement-Class A through F, Revision 29, and MP/0/B/1810/015, Welding-Piping and Valves-Removal and Replacement of Class G, H, and QA Condition 3, Revision 22, have been revised to include instructions on the use of dissolvable purge paper used as purge gas or water dams. In addition, a memorandum, dated March 20, 1998, was sent to all maintenance managers describing the event and lessons learned. The managers have reviewed this information with their teams that are involved in welding tasks. The other corrective actions described in the licensee's response were also verified as completed by the inspectors. This violation is closed.

M8.3 (Closed) LER 50-269/98-02 (Revisions 0 and 1): Non-Isolable Weld Leak on Pressurizer Surge Line Drain Pipe Causes Shutdown

Revision 0 of this LER was issued on February 26, 1998, because of the forced reactor shutdown due to a reactor coolant system leak of about 2 gallons per minute (gpm) on the pressurize surge line drain. Revision 1, issued on April 30, 1998, presented results of the metallurgical report. The analysis identified the root cause of the weld failure as externally initiated stress corrosion cracking (SCC) and vibration. The source of halides necessary to cause SCC was most likely the result of the 1973 reactor coolant pump (RCP) 1A1 motor fire, and the combustion of materials containing halides. Neither Units 2 or 3 have experienced a similar fire. Therefore, this event is not considered of concern to the other units. Further, the licensee has a chemical control program in place to prevent the introduction of halides into the reactor building.

Prior to restart from this event, the surge line and drain line were instrumented to assess vibration. Vibration data was collected during the heat-up cycle of the plant. This data has been analyzed and included in Oconee Station Calculation (O.C.) -6857-11, Revision 1. The data indicated that the displacement was below the endurance limit for stainless steel pipe with an infinite number of cycles. Thus, the licensee concluded that no fatigue usage would occur in the piping. No violations were identified during this review. Therefore, this LER is closed.

M8.4 (Closed) Apparent Violation (EEI) 50-269,270,287/98-11-05: Stroke Time Each Motor Operated Valve (MOV) to Its Safety Position(s)

This EEI involved the licensee's failure to require MOV stroke time measurements in both directions for MOVs with active safety functions in both directions (open and closed), as required by the standard specified by TS 4.0.4 and
10 CFR 50.55a. This Severity Level IV violation is being treated as a NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation was in the licensee's corrective action program as PIP 0-O98-5894. The corrective actions specified involved implementation of stroke-timing in both safety directions through changes to surveillance procedures scheduled to be completed by April 1, 1999. This EEI is closed and this item is identified as NCV 50-269,270,287/99-01-02, Stroke Time Each MOV to Its Safety Position(s).

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Operability of Keowee Hydro-Electric Unit ACBs

a. Inspection Scope (37551)

As a result of maintenance problems with the ACBs (discussed in Section M1.3), the licensee became concerned that there would be insufficient air reserve for the ACBs to operate if called upon while the KHUs were loaded for commercial operation. The inspectors reviewed the design basis aspects of the ACBs.

b. Observations and Findings

The licensee was concerned that operation of an ACB could result in internal pressure below 112 psig. At that pressure, the breaker would lock-up and not operate at all. The scenario that would result in breaker lock-up involved an emergency start signal while the KHUs were generating for commercial operation. In this scenario, the ACB associated with KHU dedicated to the overhead power path would be required to open and then close. With a low initial pressure of approximately 150 psig and assuming a worst case pressure drop on opening of 2 psig, a worst case pressure drop on closing of 30 psig, combined with instrument error and drift (6 psig), the ACB reservoir pressure could drop below 112 psig. This could result in a situation where the breaker would be incapable of opening to clear a subsequent fault. The second KHU aligned to the underground power path would be capable of supplying the emergency load. The inspectors reviewed the design documents and verified that the ACBs would remain locked in position if air system pressure decreased below 112 psig.

The licensee initiated PIP K-O99-0392, performed an operability evaluation, raised the alarm setpoint from 150 psig to 155 psig to provide more margin above the ACB lock up point, and changed the procedure for KHU commercial operation to require the ACB air pressure to be above 155 psig before starting the KHUs for commercial operation. The inspectors reviewed the PIP and will require further time to review and evaluate other possible design basis information and system interactions. The inspectors agreed that the ACBs were capable of performing their safety function at the time of the maintenance problems since the KHUs were not operating commercially. The inspectors also agreed with the licensee's immediate corrective actions. However, other factors such as the air supply system leak rate require additional consideration. The inspectors will followup on the ACB air system review and design basis via IFI 50-269/99-01-03, Keowee Pneumatic Breaker Questions.

c. Conclusions

The engineering evaluation of the problems with the Keowee air circuit breakers demonstrated a good safety assessment attitude and adequate technical support. However, remaining design basis and air system interaction questions will undergo further NRC review.

E7 Quality Assurance in Engineering

E7.1 Resolution of Difficulties Experienced in Opening Manual Feedwater Valves FDW-313 and FDW-314

a. Inspection Scope (40500)

The inspectors assessed the licensee's cause and operability evaluations and the corrective actions for difficulties that were experienced in opening the Emergency Feedwater (EFW) Header Train and Unit Crossover Isolation Valves (1,2,3FDW-313 and FDW-314). In addition, the inspectors assessed the licensee's application of the maintenance rule (10 CFR 50.65) to these crossover valves. The valves are manually operated and must be capable of being opened in the event of a secondary line break to provide an EFW flow path between units. The opening difficulties occurred during surveillance tests conducted January 20 and 29, 1999; and were documented for resolution on PIP reports 0-O99-0196 and 1-O99-0348.

The inspectors' assessments were conducted through a review of documentation, observation of licensee personnel cycling the valves, independently timing the travel to the valves, and through discussions with licensee personnel. The documents reviewed by the inspectors were the above PIPs, the current drawings for the flow path, related UFSAR and DBD entries, examples of the surveillance test records, and other documents referred to in Subsection b.

b. Observations and Findings

Background - Valve Functional Requirements

Crossover valves 1,2,3FDW-313 and -314 were installed in 1974 as part of a design change. This change provided an added source of emergency feedwater to mitigate a postulated condensate line break in the turbine building. In the event of the line break, the crossover valves could be opened to provide emergency feedwater from an unaffected unit. Subsequent to the break, the licensee has 15 minutes to determine what event was present and to have non-licensed operators open the valves. (Note: A recent licensee analysis determined the response time could be extended to 30 minutes.) Opening either crossover valve in a unit opens an emergency feedwater flow path to or from the crossover valves in the other two units. The design change was described in the licensee's April 25, 1973, Report OS-73.2, and in OS-73.2, Supplement 1, dated June 22, 1973. This design change was accepted in an NRC Safety Evaluation Report (SER) dated July 6, 1973. The SER indicated that the design change appropriately addressed required accident situations.

Background - Description of Operating Difficulties

Valves 1,2,3FDW-313 and -314 are manually operated gate valves. The valves are elevated (up to about 20 feet) and, at the times of the January 20 and 29, 1999 tests, were equipped for operation from floor level through chains mounted to the handwheels. The difficulties operating these valves were as follows:

- On January 20, 1999, Unit 3 valves 3FDW-313 and 3FDW-314 were stroke tested during plant operation per quarterly surveillance test procedure PT/3/A/0152/009. Following difficulties opening these two valves, the four crossover valves in the other units were tested. The results were as follows:

- Valves 3FDW-313 and 1FDW-313 were difficult to unseat. The efforts of two individuals were needed to unseat each valve.

  (Note: The procedure for emergency operation of these valves did not require more than one individual to be sent to open the valves.)

- The operating chains came off valves 3FDW-313 and 3FDW-314 during the tests and ladders had to be obtained to reinstall the chains.

- The operating chains on valves 1FDW-313 and 2FDW-314 appeared to be of the wrong size but did not come off during operation.

• Valve 1FDW-313 was retested on January 29, 1999, and again proved difficult to open. The efforts of three individuals were required to unseat the valve. Subsequently that day, 1FDW-313 and the other FDW-313 and -314 valves were tested and were successfully opened by one individual.

The above difficulties in opening the crossover valves would have increased the time required to respond to the design event. These difficulties, the licensee's cause and operability evaluations, and the corrective actions were documented in PIPs 0-O99-0196 and 1-O99-0348.

Cause Evaluation

As noted above, the difficulties encountered in opening these valves included greater than anticipated unseating forces and dislocation of the chains that were used to operate the valves. PIP 1-O99-0348 attributed the high unseating forces to unanticipated differential pressure across the valve disks, due to block valve leakage during a pump test which pressurized the upstream piping. Following the pump test, the pressure was apparently retained either by upstream check valves or by the block valve. PIP 0-O99-0196 attributed the chain dislocations to excessive wear caused by severe service.

Based on a review of the piping drawings and discussions with individuals present when the crossover valves were tested, the inspectors found the licensee's explanation for the unseating forces was logical. The licensee's explanation for chain dislocation was somewhat less plausible, as the need for high opening forces on the chains had only been identified in a few instances.

The licensee's overall evaluation of difficulties opening the crossover valves was documented in PIP 1-O99-0348. The evaluation concluded that the apparent cause was that the differential pressure present at the valves was higher than expected due to a leaking valve. The licensee also concluded that this higher differential pressure would not be considered in the normal design practice. The inspectors agreed with this determination.

Corrective Actions

The licensee removed the chains from the valves, lubricated the stems, calculated the torque needed to open the valves against the maximum system pressure, installed scaffolding to provide ready access to the valves, and provided cheater bars to assure that the calculated torque could be applied by one person. The inspectors subsequently observed licensee personnel opening the valves on several occasions. In each instance the valves were readily accessed from the scaffolding that had been provided and were easily opened by one individual using only the handwheel. The inspectors reviewed the licensee's calculation (included in PIP 1-O99-0348) of the torque forces to open the valves. They found the calculation was reasonably conservative and that torques determined could be readily achieved with the cheater bars that had been provided. The licensee's corrective actions provided satisfactory assurance the valves could be opened to provide their design functions.

Present Operability Evaluation

The licensee's present operability evaluation took into account the above corrective actions and concluded that the valves were operable. Based on their observations of individuals operating the valves and on their review of the licensee's evaluations and corrective actions, the inspectors concurred with the licensee's conclusion that the valves were operable.

Past Operability

The licensee's past operability evaluation assessed the steps required to open the valves and determined that flow between units could have been established within 30 minutes, the time justified in the latest accident analysis. The inspectors questioned the times which the licensee's evaluation allotted for some steps but, based on their observations, agreed that flow could have been established within 30 minutes.

Maintenance Rule

The inspectors questioned whether the crossover valves were scoped within the maintenance rule, what performance criteria applied, and how the opening difficulties were to be handled under the rule. The licensee provided "Maintenance Rule: SSC Summary Sheets" from Oconee's program which showed that the crossover valves had been included. The sheets specified system level functional performance criteria which would apply to the performance of the crossover valves. Function EFW.3 captured the function to "provide backup emergency feedwater to other Oconee units." The licensee stated that the crossover valve difficulties had not been screened yet to establish any actions in accordance with the rule, as 60 days were allowed for this action. In reviewing the maintenance rule sheets, the inspectors noted that function EFW.3 was designated not risk significant. The risk reduction worth assigned to satisfactory completion of this function was reported to be 1.017, normally indicating a risk significant function. However, the licensee stated that its expert panel had determined that the function was not risk significant from a maintenance rule standpoint because human error dominated in the functional failure. The inspectors questioned whether this classification was justified and noted that for this classification, four maintenance preventable functional failures were being permitted per fuel cycle. The licensee surveillance tested these valves about 36 times per fuel cycle. The four failures permitted by the licensee results in an unreliability of about 1.2E-1 (12 failures per 100 demands). The licensee's probabilistic risk assessment indicates that failing to operate one of these valves due to human error has a probability of occurrence of 5E-2 (5 failures per 100 demands). This suggests that human error may not dominate. The adequacy of the licensee's determination that function EFW.3 is not risk significant was considered unresolved and is to be further reviewed with the licensee.

c. Conclusions

The licensee satisfactorily established the cause, evaluated the current and past operability, and provided appropriately conservative corrective actions for difficulties experienced in opening emergency feedwater crossover valves FWD-313 and -314. Overall, the licensee's resolution of the difficulties experienced in opening the emergency feedwater crossover valves was considered good.

The inspectors questioned the licensee's designation of maintenance rule function EFW.3, "provide backup emergency feedwater to other Oconee units," as not risk significant. This was identified as URI 50-269,270,287/99-01-04, Maintenance Rule EFW Backup Function.

E7.2 Near Term Corrective Actions for Configuration Management Deficiencies (Recovery Plan Item DB10)

a. Inspection Scope (40500)

The inspector reviewed the licensee's implementation of corrective action plans developed to resolve configuration management deficiencies. Specifically, the implementation of the Configuration Management initiatives delineated in Section 4.0 of the Oconee Engineering Division Configuration Management Improvement Team Charter, Revision 5, was evaluated to verify compliance with the requirements of 10 CFR 50 Appendix B, Criterion XVI, Corrective Actions.

b. Observations and Findings

The inspector evaluated how effectively corrective actions for configuration management deficiencies were being implemented by review of objective evidence in the licensee's corrective action program. Interviews were conducted with engineering personnel concerning the status of near term corrective actions. Additionally, changes in scope to the developed corrective action plans involving deletion of action items were also evaluated to determine the potential impact on (1) the results of the extent of condition review performed for configuration management (CM) deficiencies; (2) the primary and contributing root causes identified in the root cause analysis performed for CM deficiencies; and (3) the effectiveness of the recurrence controls to be established by the long-term corrective actions. The degree of involvement of the Site Configuration Management Steering Committee in changes made to the developed corrective action plans was also evaluated in order to verify adequate implementation of the corrective action program in accordance with the requirements of 10 CFR 50 Appendix B, Criterion XVI.

Oconee Engineering Division CM Improvement Team Charter

Revision 5 of the CM Improvement Team Charter Section 4.0, Near Term Actions, consisted of the following action items:

- Section 4.1, Establish Monthly PIP Monitoring/Trending of Configuration Control Errors
- Section 4.2, Establish Near Term Actions to Immediately Reduce Configuration Errors

- Section 4.3, Establish Periodic Configuration Self-Assessment Requirements
- Section 4.4, Implement a Standard Configuration Pre-Job Briefing Form
- Section 4.5, Configuration Management Training-NSD-106 and Operating Experience
- Section 4.6, Monthly Reporting Requirements

The inspector determined that the licensee has established monthly PIP trending of CM errors which were documented in the Oconee Nuclear Station Configuration Management monthly reports. The inspector reviewed the report for January 1999 and evaluated the twelve month rolling average for the following performance indicators:

- Document Related PIP-More Significant Event/ Less Significant Event Ratio
- Number of Missed Technical Specification Surveillance
- Number of Mispositions
- Temporary Modifications Outstanding

The above performance indicators were selected for use by the licensee in Revision 5 of the CM Improvement Team Charter dated January 1, 1999. These performance indicators were different from those in previous revisions of the CM Improvement Team Charter and was based on the three site 1999 goals addressed by the licensee's memorandum dated December 14, 1998, RE: Oconee Nuclear Site, Configuration Management Program Manual Holders. A documented basis for changing the performance indicators was requested but was not available from the licensee. The inspector determined that both the Configuration Management Measures Monthly reports for December and January showed a CM index of 3 which was colored yellow. This color was indicative of the CM meeting its year to date (YTD) goal with an adverse trend projected not to meet its year end (YE) goals.

Corrective Action Item 4.1.2 diagnostic measures for January 1999 was determined to be incomplete. This corrective action had not yet been completed at the time of the inspection. In response to this inspection finding on February 24, 1999, the licensee revised the CM Diagnostic Measures to include information up to January 1, 1999.

Corrective Action Item 4.2 was intended to establish near term actions to immediately reduce the CM errors. These corrective actions were deleted from the CM Improvement Team Charter as shown on Revision 5 dated January 27, 1999. In discussions with engineering personnel the inspector determined that the licensee did not perform an evaluation to assess the impact of the deleted corrective actions on (1) the results of the extent of condition review performed for CM deficiencies; (2) the primary and contributing root causes identified in the root cause analysis performed for CM deficiencies; and (3) the effectiveness of recurrence controls to be established by the long term corrective actions. The licensee did not provide objective evidence which demonstrated that the scope changes to near term corrective actions were performed in a controlled manner. Neither was objective evidence presented which demonstrated that the Site Configuration Management Steering Committee was cognizant of and had been involved in these scope changes.

Corrective Action Item 4.3 required the licensee to establish a review schedule for periodic Level 1 assessment reviews of representative samples of calculations and other configuration document changes. At the time of the inspection, this item had not been completed.

Corrective Action Item 4.4 required the licensee to establish a standard configuration pre-job briefing form for all high risk calculation changes. The licensee provided the inspector a copy of procedure EM-3.5, Engineering Risk Assessment Process, Revision 0, which was identified as having met the requirements for Corrective Action Item 4.4. The inspector reviewed this procedure and determined that it provided guidance for identifying all high risk engineering activities including calculations. Pre-job briefings are required to be conducted with individuals to ensure that they understand the scope, risks, precautions and contingencies for the high risk activity to be performed. A pre-job briefing form included in the procedure did not, however, specifically provide guidance which ensured that high risk calculations do not contain errors.

The inspector reviewed procedure EDM-101, Engineering Calculations/Analyses, Revision 9, and verified that sufficient guidance was provided in Appendix D to adequately address the concern identified in Corrective Action Item 4.4 for electrical and instrumentation and control calculations. A similar checklist for mechanical/nuclear and structural/civil calculations was not contained in the procedure.

Discussions with engineering personnel revealed no inadequacies with the implementation of Corrective Action Item 4.5, Configuration Management Training-NSD-106 and Operating Experience.

<u>Oconee Engineering Division Focus Area Annunciator Panel Reports</u>

Corrective Action Item 4.6 required monthly reporting of team activities to selected site management. The inspector reviewed the Oconee Engineering Division Focus Area Annunciator Panel input prepared for January 1999 and determined that the following corrective actions had not been included in the report:

- Action Item 4.1.2, Diagnostic Measures
- Action Item 4.1.3, Establish Periodic Configuration Self-Assessment Requirements
- Action Item 4.1.4, Implement Standard Configuration Pre-Job Briefing Form

None of the above action items was started as of February 25, 1999, and with the exception of Item 4.1.4, the licensee did not provide objective evidence which showed what the status of the action items was. The inspector verified that the two most recently issued Engineering Division Focus Area Annunciator Panel reports dated December 16, 1998, and December 31, 1998, did not include any of the above action items. The inspector concluded that information provided to station management did not accurately describe the scope of the corrective actions required to implement Section 4.0 of the CM Improvement Team Charter and failed to provide information concerning the status of these open items.

On February 24, 1999, the licensee revised the Configuration Management Improvement Team Charter (Revision 6) to include action items which had been deleted in Revision 5. Action items that had not been completed at the start of the inspection were also completed to accurately show the status of these items. The inspector was informed that the Engineering Division Focus Area Annunciator Panel report would be reformatted to include both performance and diagnostic measures. Additionally, the report scheduled for issue in March would include the status of all action items delineated in the CM improvement team charter.

NRC Configuration Management Criteria

The licensee performed a Level 1 self-assessment which completed a key-milestone for evaluating the effectiveness of the licensee's configuration management program. The assessment was based on the licensee's review of NRC IP 37702, Design Changes and Modification Program. The inspector reviewed the result of this assessment and determined that the license had demonstrated that the plant's design control program complied with the requirements of 10 CFR 50, Appendix B and American National Standards Institute (ANSI) N45.2.11-1974. Quality assurance requirements delineated in the ANSI standard and 10 CFR 50, Appendix B, Criterion III, was adequately incorporated in the design control process. Effective implementation of the design control process should provide reasonable assurance for maintaining configuration management.

c. Conclusion

The inspector concluded that near term corrective actions developed for configuration management deficiencies were being poorly implemented. Changes to Section 4.0 of the CM Improvement Team Charter were not evaluated for effect on interim resolutions nor the effectiveness of recurrence controls to be implemented by the long-term corrective actions.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) EEI 50-269,270,287/98-11-07: Three Examples of Failure to Meet the Requirements of 10 CFR 50 Appendix B, Criterion XVI

This EEI involved three examples of untimely and/or ineffective licensee corrective actions for conditions adverse to quality. The examples were identified by NRC inspectors and represent a violation of the requirements of 10 CFR 50, Appendix B, Criterion XVI. This item was left as an EEI pending licensee development of their corrective action. This violation was in the licensee's corrective action program as PIP 4-O98-5953. This PIP indicated that the apparent causes would be determined and that the initial corrective actions would be completed by March 10, 1999. The corrective actions proposed in the PIP included a review of the effectiveness and timeliness of corrective actions implemented at the Oconee site. This Severity Level IV violation is being treated as a NCV, consistent with Appendix C of the NRC Enforcement Policy. This EEI is closed and the issue is identified as NCV 50-269,270,287/99-01–05, Three Examples of Failure to Meet the Requirements of 10 CFR 50 Appendix B, Criterion XVI.

E8.2 (Closed) VIO 50-269/97-16-07: Failure to Translate RCP Net Positive Suction Head (NPSH) Requirements

The corrective actions described in the licensee's response dated February 25, 1998, were verified by the inspectors as completed. The activities related to the RCP impeller removal and initial evaluations were discussed in NRC IRs 50-269,270,287/97-14 and 97-15.

The violation of RCP NPSH requirements was attributed to ineffective communications between engineering and operations personnel. To resolve this, interface meetings between engineering and operations are held periodically to discuss evolving equipment and operational concerns. The inspector attended one of these meetings on February 5, 1999. The meeting was attended by seven people and was conducted as an open meeting with a prepared agenda. Discussions were held on a number of current items needing attention. After the meeting, a brief discussion was held with the operations personnel. These meetings are considered beneficial, as they focus on the issues requiring attention.

The design basis document describing RCP A1, A2, B1, and B2 was revised on July 15, 1998, to provide guidance when operating a single pump in a loop. This is included in Part 20.4.1.2, Revision 4 of the Design Basis Document.

Video inspections of Unit 2 and Unit 3 RCPs have been performed. The data has been reviewed by Oconee Engineering, Framatone Engineering and Sulzer-Bingham Pump (original equipment manufacture). Operability results of these reviews are included in O.C.-7180. Operability of Unit 1 RCPs is documented in O.C.-7046. This violation is closed.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on March 2, 1999. The licensee acknowledged the findings presented. No proprietary information was identified to the inspectors.

Partial List of Persons Contacted

Licensee

L. Azzarello, Design Basis Engineering Manager
E. Burchfield, Regulatory Compliance Manager
T. Coutu, Superintendent of Operations
T. Curtis, Mechanical System/Equipment Engineering Manager
G. Davenport, Operations Support Manager
B. Dobson, Engineering Work Control Manager
J. Forbes, Station Manager
W. Foster, Safety Assurance Manager
T. Hartis, Recovery Plan Coordinator
D. Hubbard, Modifications Manager
C. Little, Civil, Electrical & Nuclear Systems Engineering Manager
W. McCollum, Site Vice President, Oconee Nuclear Station
B. Medlin, Superintendent of Maintenance
M. Nazar, Manager of Engineering
J. Smith, Regulatory Compliance
J. Twiggs, Manager, Radiation Protection
B. Millsaps, Rotating Equipment Manager

Other licensee employees contacted during the inspection included technicians, maintenance personnel, and administrative personnel.

Inspection Procedures Used

IP37551	Onsite Engineering
IP40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP61726	Surveillance Observations
IP62707	Maintenance Observations
IP71707	Plant Operations
IP71750	Plant Support Activities
IP92700	Onsite Followup of Written Event Reports
IP92901	Followup - Operations
IP92902	Followup - Maintenance
IP92903	Followup - Engineering
IP93702	Prompt Onsite Response to Events

Items Opened, Closed, and Discussed

Opened

50-269,270,287/99-01-01	NCV	Failure to Follow Procedure for Obtaining Spare Parts (Section M8.1)
50-269,270,287/99-01-02	NCV	Stroke Time Each MOV to Its Safety Position(s) (Section M8.4)
50-269/99-01-03	IFI	Keowee Pneumatic Breaker Questions (Section E2.1)
50-269,270,287/99-01-04	URI	Maintenance Rule EFW Backup Function (Section E7.1)
50-269,270,287/99-01-05	NCV	Three Examples of Failure to Meet the Requirements of 10 CFR 50 Appendix B, Criterion XVI (Section E8.1)

Closed

50-269,270,287/98-11-01	IFI	Keowee Commercial Operation to Emergency Start Evaluation (Section O8.1)
50-270,287/97-01-03	VIO	Failure to Follow Valve Procedure (Section O8.2)
50-270/96-07 (Rev 0 - 2)	LER	LPI System Technically Inoperable for Appendix R Scenario Due to Inadequate Work Practices (Section O8.2)
50-269,270/98-02-04	VIO	Failure to Follow Procedure for Foreign Material Control (Section O8.3)
50-269,270,287/98-08-01	URI	Configuration Control of the Station ASW Pump (Section M8.1)

50-269/98-01-02	VIO	Maintenance Procedure MP/0/A/1810/014 Provided Inadequate Instructions for Use of Purge Paper as Weld Damming Material (Section M8.2)
50-269/98-02 (Rev 0 -1)	LER	Non Isolable Weld Leak on Pressurizer Surge Line Drain Pipe Causes Shutdown (Section M8.3)
50-269,270,287/98-11-05	EEI	Stroke Time Each MOV to Its Safety Position(s) (Section M8.4)
50-269,270,287/98-11-07	EEI	Three Examples of Failure to Meet the Requirements of 10 CFR 50 Appendix B, Criterion XVI (Section E8.1)
50-269/97-16-07	VIO	Failure to Translate RCP NPSH Requirements (Section E8.2)

List of Acronyms

ACB	Air Circuit Breakers
ANSI	American National Standards Institute
ASW	Auxiliary Service Water
CA	Corrective Action
CFR	Code of Federal Regulations
CM	Configuration Management
DBD	Design Basis Document
EEI	Apparent Violation
EOP	Emergency Operating Procedure
ES	Engineered Safeguards
FIP	Failure Investigation Process
FME	Foreign Material Exclusion
GPM	Gallons Per Minute
HPI	High Pressure Injection
I&E	Instrument and Electrical Department
IFI	Inspector Followup Item
INPO	Institute of Nuclear Power Operations
IP	Inspection Procedure
IR	Inspection Report
KHU	Keowee Hydro-Electric Unit
KW	Kilowatt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
MATCON	Material Condition
MOV	Motor Operated Valve
MPM	Motor Power Monitoring
NCV	Non-Cited Violation
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NSD	Nuclear Site Directive
OMP	Operation Management Procedures

ONS	Oconee Nuclear Station
O.C.	Oconee Station Calculation
PDR	Public Document Room
PIM	Plant Issue Matrix
PIP	Problem Investigation Process
PM	Preventive Maintenance
PMG	Permanent Magnet Generator
PSIG	Pounds Per Square Inch Gauge
PT	Performance Test
PZR	Pressurizer
QA	Quality Assurance
QC	Quality Control
RCP	Reactor Coolant Pump
SCC	Stress Corrosion Cracking
SEA	Safety Evaluation Report
SLC	Selected Licensee Commitment
SSF	Standby Shutdown Facility
SSW	Siphon Seal Water
TDEFW	Turbine Driven Emergency Feedwater
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation
WO	Work Order
YE	Year End
YTD	Year To Date