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:	July 26 - September 5, 1998
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Enclosure 2

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2, and 3
NRC Inspection Report 50-269/98-08,
50-270/98-08, and 50-287/98-08

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a six-week period of resident inspection, as well as the results of announced inspections by seven Region based inspectors. [Applicable template codes and the assessment for items inspected are provided below.]

Operations

- The Unit 1 shutdown was performed in a controlled fashion with good command and control. (Section O1.3, [1A, 3B - Good])

- The engineering evaluation to support the return to service of the Unit 3 auxiliary fan coolers was adequate **(Recovery Plan Item DB8)**. (Section O1.4, [4B, 5C - Adequate])

- Pre-job briefs to support return to service of the Unit 3 auxiliary fan coolers were good in that they contained appropriate detail and stressed procedure adherence **(Recovery Plan Item DB8)**. (Section O1.4, [1A, 3B - Good])

- The evaluation and followup actions established by the licensee in response to lack of oil in a reactor building spray pump were adequate. (Section O1.5, [4B, 5B, 5C - Adequate])

- The compensatory actions established in response to the licensee's identification of another water hammer scenario identified during a Generic Letter 96-06 review were adequate **(Recovery Plan Item DB8)**. (Section O1.5, [4B, 5A - Adequate])

- The inoperability of both trains of the essential siphon vacuum system on Unit 2 was due to a procedure weakness that resulted in a mispositioned valve **(Recovery Plan Item DB4)**. (Section O1.5, [2B - Poor])

- Once the potential inoperability of the essential siphon vacuum system was recognized, the licensee took rapid action to return the system to readiness and made appropriate notifications to the NRC **(Recovery Plan Item DB4)**. (Section O1.5, [5A, 5B, 5C - Adequate])

- During the Unit 1 return to power operations, the licensee adequately responded to a condensate air ejector radiation monitor alarm. This showed a marked improvement over a past occurrence, which resulted in a non-cited violation. (Section O1.6, [1B - Adequate])

- The Unit 1 startup from a forced outage was performed effectively. The operators' responses to annunciators, monitoring of parameters, supervisor control, the use of procedures, communications, and

management oversight were good. (Section O1.6, [1A, 3B - Good])

- Poor communications between operations and material condition personnel resulted in tape remaining on the stem of an operable safety-related low pressure injection valve for three days. This was considered a weakness in communications between site organizations. (Section O4.1, [1A, 3A - Poor])

- The licensee's activities involving the Technical Specification change and administrative controls in place to require three high pressure injection pumps to be operable above 350 degrees F were adequate. (Section O8.1, [4C - Adequate])

- The analysis performed to ascertain reactor building sump operability, causes of discovery, and resolution were timely and complete. (Section O8.2, [5B, 5C - Adequate])

- The discovery and subsequent corrective actions for a failure to perform a low pressure injection flow instrument surveillance were timely and thorough. (Section O8.3, [5B, 5C - Adequate])

- Following the inspection and recognition of the significance of the failure to install cotter pins on main steam safety valves, the licensee took prompt and thorough corrective measures. (Section O8.4, [5B, 5C - Good])

- The recognition and response by the operators to a failure of main feedwater while shutdown, and the resolution were considered timely and thorough. (Section O8.5, [1A, 5A, 5C - Good])

- The resolution and corrective action in response to an inadequate procedure for voltage regulator adjustment were timely and thorough. (Section O8.6, [5B, 5C - Adequate])

- The licensee's analysis and resolution of the issues related to the May 3, 1997, Unit 3 high pressure injection event were timely and thorough. (Section O8.7, [5B, 5C - Good])

Maintenance

- The maintenance activities observed were, in general, completed thoroughly and professionally. (Section M1.1, [3A, 3B - Adequate])

- Due to potential procedural and work control problems, packing practices on the safety-related station auxiliary service water pump showed a lack of attention to detail. This item was left unresolved pending additional NRC review of pump packing procedures, material controls, and work control requirements. (Section M1.2, [2B - URI])

- The licensee's plans for inservice inspection and steam generator examinations during the Fall 1998, Unit 3 refueling outage were comprehensive **(Recovery Plan Item SE8)**. (Section M3.1, [2B - Good])

Engineering

- The Oconee Safety-Related Designation Clarification Program was two years behind its original completion schedule of January, 1997. The licensee had essentially kept the program on its revised schedule during the last 11 months of increased oversight, and overall progress on the program during the last year was adequate **(Recovery Plan Item DB3)**. (Section E1.1, [4A, 5C, - Adequate])

- Some of the level of detail in the partially completed Oconee Safety-Related Designation Clarification Program database of components relied upon to mitigate accidents was good, in that related indication and associated components were included **(Recovery Plan Item DB3)**. (Section E1.1, [4C - Good])

- Some equipment was notably missing from the partially completed Oconee Safety-Related Designation Clarification Program database, such as electrical power supplies **(Recovery Plan Item DB3)**. (Section E1.1, [4C - Poor])

- The repair practice on the non-safety-related 1B1 reactor coolant pump lower oil reservoir that had perpetuated a repetitive minor oil leak was poor. The leak from the reservoir was the reason for the Unit 1 shutdown this period. (Section E1.2, [2A, 3A, 5B - Poor])

- Engineering analysis of the current self-disclosing 1B1 reactor coolant pump reservoir leak was good. (Section E1.2, [4B, 5B - Good])

- Engineering analysis of the self-disclosing 1A2 reactor coolant pump seal problem was good. (Section E1.2, [5B - Good])

- The use of the problem investigation process to track to closure corrective actions for NRC open items and commitments involving the emergency power system and the quality of this process were good **(Recovery Plan Item DB7)**. (Section E1.3, [5C - Good])

- The use of the failure investigation process reports, at management direction when necessary, by engineering to address significant issues involving the emergency power system and the quality of the failure reports was excellent **(Recovery Plan Item DB7)**. (Section E1.3, [4B - Excellent])

- The onsite engineering group was addressing the NRC open items and commitments involving the emergency power system in a sound technical manner, with appropriate resources, using approved methods, and with management and supervisory oversight **(Recovery Plan Item DB7 - Closed)**. (Section E1.3, [4B, 5B, 5C - Good])

- A violation was identified for an inadequate 50.59 safety evaluation, for a 1996 Final Safety Analysis Report revision, which failed to identify an unreviewed safety question related to the net positive suction head for the reactor building spray pumps. (Section E1.4, [4A, 4B - Poor])

- Although the licensee failed to adequately identify the licensing basis related to reactor building spray pump net positive suction head assumptions; they performed appropriate, timely analysis to assure operability of the pumps. (Section E1.4, [5B - Adequate])

- Screening of Problem Investigation Process reports was generally good in that the significance level was appropriately identified. Downgrading of Problem Investigation Process reports was adequately controlled **(Recovery Plan Item SA2)**. (Section E2.1, [5B - Good])

- Operability evaluations of Problem Investigation Process report identified problems were adequate **(Recovery Plan Item SA2)**. (Section E2.1, [5B - Adequate])

- Problem Investigation Process report cause determinations and assigned corrective actions were adequate **(Recovery Plan Item SA2)**. (Section E2.1, [5B, 5C - Adequate])

- The Problem Investigation Process corrective action backlog, as stated in the Oconee Recovery Plan, provided an inaccurate and unclear assessment of the overall Problem Investigation Process corrective action backlog. Specifically, the recovery plan stated that there were 232 open Problem Investigation Process corrective actions greater than six months old, while other performance indicators showed the actual number was approximately 660 (which included 428 management exception items) open Problem Investigation Process corrective actions **(Recovery Plan Item SA1)**. (Section E2.1, [5C - Poor])

- The Problem Investigation Process quality reviews performed by the Safety Review Group were effective in identifying areas for improvement in the Problem Investigation Process **(Recovery Plan Item SA2)**. (Section E7.1, [5A - Good])

- The in-plant reviews of the Oconee Recovery Plan were being performed in accordance with established schedules. However, programs and directives under which the Independent Nuclear Oversight Team will function were still in the process of being revised to reflect the Safety Review Group organization (including the Independent Nuclear Oversight Team roles and responsibilities) **(Recovery Plan Item SA4)**. (Section E7.1, [5A - Adequate])

- A non-cited violation of the maintenance rule was identified by the inspectors for a failure to monitor the performance of manual caustic injection valves. (Section E8.1, [3A, 2B - Poor])

- The licensee promptly responded to the maintenance rule violation, including cycling the caustic injection valves to assure that they were capable of fulfilling their intended function and revising a procedure to include cycling the valves annually. (Section E8.1, [5C - Good])

- The inspectors identified a poor design condition for both timely access to equipment and personnel safety in that operator access to the

handwheel of Unit 3 emergency feedwater flow control valve FDW-316 involved walking on a horizontal pipe about 15 feet above the floor. This condition had existed for many years without licensee identification and corrective action **(Recovery Plan Item DB9)**. (Section E8.1, [4A, 5A - Poor])

- The recent leak sealing in the Unit 3 control room ventilation system outside the control room was very thorough and professional. This leak sealing resulted in a substantial improvement in the attainable pressure in the Unit 3 control room **(Recovery Plan Item NRC3)**. (Section E8.2, [4B, 5C - Good])

- The licensee's procedures, oversight, and performance of a surveillance test of the Unit 2B penetration room ventilation system air flow, using a pitot tube, were good **(Recovery Plan Item NRC3)**. (Section E8.3, [2B, 4B, 5C - Good])

- The licensee's review of the history and causal factors associated with an issue involving fuses in the reactor trip confirm circuit was thorough and timely. (Section E8.4, [4A, 5B, 5C - Good])

- A non-cited violation was identified for improper design basis assumptions regarding the high pressure injection system injection and crossover valves. (Section E8.5, [4A - Poor])

- The identification, analysis, and resolution of the design basis concerns related to the failure of Valve 1HP-27 to close were adequate. (Section E8.5, [5A, 5B, 5C - Adequate])

- Based on the sample reviewed, the licensee exhibited good progress in the evaluation and resolution of the outliers for the Seismic Qualification Utility Group program. Most outliers resolved to date have been through analyses or documentation review. More complex outliers remain to be resolved by repairs, modifications, or refined analyses **(Recovery Plan Item DB6 - Closed)**. (Section E8.6, [4B, 5B, 5C - Good])

- Inspector identified deficiencies found in the seismic mounting of the nitrogen supply lines for all three units degraded the emergency feedwater systems and indicated a weakness in maintaining the nitrogen supply line supports **(Recovery Plan Item DB6)**. (Section E8.7, [2A, 5A - Poor])

Plant Support

- The licensee was effectively maintaining controls for radioactive material storage and radioactive waste processing. Work practices observed during radioactive waste processing were good. (Section R1.1, [1C, 3A - Good])

- The licensee's water chemistry control program for monitoring primary and secondary water quality had been effectively implemented in

accordance with the Technical Specification requirements and the Station Chemistry Manual for water chemistry. The collection of the samples was performed in accordance with the licensee's chemistry sampling procedure. (Section R1.2, [1C, 3A - Good])

- The inspectors concluded radiation and process effluent and environmental monitors were being maintained in an operational condition to comply with Technical Specification requirements and Updated Final Safety Analysis Report commitments. (Section R2.1, [2A - Adequate])

- The meteorological instrumentation had been adequately maintained and the meteorological monitoring program had been adequately implemented. (Section R2.2, [2A, 1C - Adequate])

Report Details

Summary of Plant Status

Unit 1 began the period at 100 percent power. On August 8, 1998, the unit was shutdown due to reactor coolant pump motor lube oil and pump seal problems. On August 27, 1998, the unit was returned to and ended the period at 100 percent power.

Unit 2 began and ended the period at 100 percent power.

Unit 3 began the period at 100 percent power. On August 25, 1998, the unit began an end-of-cycle power reduction and ended the period at 91 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.

O1.2 Operations Clearances (71707)

The inspectors reviewed the following clearances during the inspection period:

- 98-2910 1MS-87 Air Actuator Preventive Maintenance
- 98-2816 Perform MPM Test of 1MS-84

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

O1.3 Unit 1 Reactor Coolant Pump (RCP) Problems and Forced Shutdown

a. Inspection Scope (71707,93702)

On August 8, 1998, Unit 1 was shutdown (SD) due to several RCP problems. The inspectors observed pump operations, plant conditions, operator actions, and observed management interactions during the shutdown.

b. Observations and Findings

On August 7, 1998, at 5:00 a.m., Unit 1 received a RCP 1A2 Seal Outlet Flow Hi/Low alarm due to number 2 shaft seal leakage above 4.0 gallons per minute (gpm). In accordance with licensee procedures, if leakage exceeded 4.5 gpm, the unit would require SD due to the inability of the standby shutdown facility (SSF) to provide adequate emergency seal flow. The licensee appropriately established an administrative limit on the pump shaft seal leakage to ensure that this value would not be exceeded and made plans for an outage on August 14, 1998.

On August 8, 1998, at 3:50 a.m., Unit 1 received a RCP Motor 1B1 Oil Pot Low Level alarm. Operators verified the leakage and noted that RCP 1B1 lower motor bearing reservoir level had dropped about 0.4 inches over a short period. The operators also observed increasing bearing temperatures. The oil loss had begun on August 3, 1998, but the leakage rate had not increased until August 8, 1998, (total drop of 0.8 inches). These oil levels are not normally trended.

At 4:30 a.m., operations began a controlled plant power reduction. At approximately 69 percent power, the 1B1 pump was SD. After consultation with management, power was further reduced to take the plant off line. The inspectors observed the shutdown.

c. Conclusions

The SD was performed in a controlled fashion with good command and control of the plant.

O1.4 Return to Service of the Unit 3 Auxiliary Fan Coolers (AFC)

a. Inspection Scope (71707)

The inspectors followed the return to service of the Unit 3 AFCs following engineering evaluation to resolve Generic Letter (GL) 96-06 water hammer concerns.

b. Observations and Findings

The removal of the Unit 3 AFCs was originally discussed in Inspection Report (IR) 50-267,270,287/96-20 and Licensee Event Report (LER) 50-269/97-02. Prior to the return-to-service, the inspectors reviewed the engineering evaluations and 10 CFR 50.59 review. The inspectors noted that the engineering evaluations were thorough and complete.

Utilizing OP/3/A/1104/10, Revision 58, Enclosure 3.23, Filling Reactor Building Auxiliary Fan Coolers, the licensee satisfactorily returned the Unit 3 AFCs to service. This return to service was based on the licensee's satisfactory completion of an evaluation which demonstrated that despite the existence of potential water hammer concerns, the Unit 3 low pressure service water (LPSW) system would perform its safety function during normal and accident conditions.

The inspectors were present for the pre-job briefs and observed low pressure service water (LPSW) and reactor building (RB) responses to the flow changes. The pre-job briefs contained appropriate detail and stressed proper procedure implementation. The procedure was carried out as written and plant response was appropriate. The return-to-service did not perturb LPSW flow to the reactor building cooling units (RBCUs), but did reduce RB temperatures significantly. The licensee appropriately verified, through inspection and normal sump changes, that the AFCs did not leak.

The licensee indicated that the remaining units' AFCs will be returned to service as the supporting analysis is completed on each unit. Additional NRC review of this issue will occur during the review of LER 50-269/97-02.

c. Conclusions

The engineering evaluation to support the return to service of the Unit 3 auxiliary fan coolers was adequate. Pre-job briefs to support return to service of the Unit 3 auxiliary fan coolers were good in that they contained appropriate detail and stressed procedure adherence.

O1.5 Licensee 10 CFR 50.72 Notifications

a. Inspection Scope (92712, 71707)

The inspectors reviewed the following licensee notifications to the NRC:

- On June 30, 1998, the licensee completed a notification for both trains of the reactor building spray (RBS) system being out-of-service. On July 30, 1998, following completion of an engineering evaluation, the licensee retracted the notification.

- On August 13, 1998, a notification was made for a potential GL 96-06 scenario involving a water hammer in the LPSW pipe within containment.

- On August 31, 1998, the licensee completed a notification for both trains of the essential siphon vacuum (ESV) system being out of service.

The inspectors reviewed the notification issues and the corrective actions taken.

b. Observations and Findings

The inspectors made the following observations:

- On July 30, 1998, following completion of an engineering evaluation, the licensee retracted the June 30, 1998, notification regarding a low oil reservoir level on the 1A RBS pump. The licensee's evaluation determined that the oil remaining in the

pump was sufficient to lubricate its bearings. Engineering also determined that the leak mechanism was self-limiting and therefore could not cause the pump to be inoperable. Based on their review of the evaluation and discussion with the licensee, the inspectors agree with this assessment. Duke also no longer plans to submit an LER on this event. This issue was initially addressed in IR 50-269,270,287/98-07.

- On January 24, 1997, Oconee Nuclear Station completed a GL 96-06 notification to report that analysis performed pursuant to GL 96-06 had predicted water hammer in portions of the LPSW piping. LER 50-269/97-02, Revision 1, submitted July 31, 1997, addressed that analysis, and the corrective actions. On August 13, 1998, the licensee identified another scenario that was predicted to result in severe water hammers in the LPSW piping inside containment. This scenario involves having LPSW isolated or reduced below 420 gpm, when a loss of coolant accident (LOCA) or main steam line break occurs. The analysis indicates that a water hammer may occur that could breach the piping. All RBCUs currently are in service with greater than 420 gpm flow. An administrative limit of 550 gallons per minute (gpm) has been set to ensure containment integrity is maintained. Historically, the RBCU outlet valves have been tested on a quarterly basis which does decrease flow to less than 420 gpm during the test. The licensee indicate that this will be addressed in a supplement to LER 50-269/97-02. The inspectors verified that all nine RBCUs had flow greater than 420 gpm and that the operators were aware of the new minimum flow criteria (operator guidance had been issued).

- On August 28, 1998, ESV train 2A was removed from service for testing by procedure PT/2/A/0261/010, Revision 010. A 72-hour TS 3.19 LCO was entered for ESV 2A train. Testing was completed, the ESV 2A train was placed back in service, and the LCO was exited on August 28, 1998. On August 31, 1998, ESV 2B train was removed from service for testing and TS 3.19 was entered. During the conduct of testing on the Train B equipment, test personnel realized that the procedure for the Train B testing did not re-open the suction block valve for the Train B equipment. Licensee personnel then determined that the ESV 2A suction block valve was still closed from the previous testing. As a result of this procedure error, ESV 2A train was inoperable while the ESV 2B train was also inoperable for testing. This placed Unit 2 in a TS 3.0, a 12-hour LCO for having both trains of ESV inoperable. It appears that both trains were inoperable for approximately 3 hours, from 11:00 a.m to 2:00 p.m. Following the discovery of the mispositioned valve, the licensee reopened the ESV 2A suction block valve, completed a procedure change to the ESV test procedure to open the ESV 2B suction block valve prior to exiting the LCO, initiated PIP 2-098-4153, and initiated a 10 CFR 50.72 notification to the NRC. The inspectors verified that the valves were returned to their correct position and that the procedure had

been corrected. This event will be followed by the NRC through LER 50-270/98-06.

c. Conclusions

The evaluation and followup actions established by the licensee in response to lack of oil in a reactor building spray pump were adequate.

The compensatory actions established in response to the licensee's identification of another water hammer scenario identified during a GL 96-06 review were adequate.

The inoperability of both trains of the essential siphon vacuum system on Unit 2 was due to a procedure weakness which resulted in a mispositioned valve. Once the potential inoperability of the essential siphon vacuum system was recognized, the licensee took rapid action to return the system to readiness and made appropriate notification to the NRC.

01.6 Unit 1 Startup Observations

a. Inspection Scope (71707)

Unit 1 was started on August 27, 1998, after a forced outage due to RCP problems. The inspectors observed the startup.

b. Observations and Findings

During the return to power, the condensate air ejector radiation monitor, RIA-40, alarmed. This was an expected occurrence due to chemistry changes which occurred in the secondary system. The operators, health physics personnel, and chemist took appropriate action to understand the alarm and followup through successive shifts. This was marked improvement in RIA-40 interface performance as compared to that indicated in Inspection Report 50-269,270,287/97-18, Section 01.3, where the licensee's procedure problems were identified during a steam generator tube leak event. The current alarm had no significance but was important in that the licensee showed increased understanding in this area.

During the return to power operations, the inspectors observed the operators' responses to annunciators, monitoring of parameters, supervisor control, communications, the use of procedures, and management oversight. Access to the control room was restricted to necessary personnel only. Shift turnovers were well planned and controlled.

c. Conclusions

During the Unit 1 return to power operations, the licensee adequately responded to a condensate air ejector radiation monitor alarm. This showed a marked improvement over a past occurrence which resulted in a

non-cited violation (NCV).

The Unit 1 startup from a forced outage was performed effectively. The operators' responses to annunciators, monitoring of parameters, supervisor control, communications, the use of procedures, and management oversight were good.

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Feature (ESF) System Walkdowns (71707)

The inspectors used IP 71707 to walkdown accessible portions of the following ESF systems:

- Siphon Seal Water (Unit 2)
- Essential Siphon Vacuum (Unit 2)
- Emergency Feedwater (Unit 3)

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the licensee's attention and were corrected.

02.2 Containment Isolation Lineup (71707)

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

- Unit 3 South Low Pressure Injection (LPI) Room

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

04 Operator Knowledge and Performance

04.1 Tape Found on Stem of Valve 3LP-22

a. Inspection Scope (71707)

On September 2, 1998, during routine tours of the Unit 3 auxiliary building, the inspectors found masking tape on the stem and parts of the motor operator for borated water storage tank (BWST) suction valve 3LP-22. The inspectors questioned the operability of the LPI system and discussed the issue with the appropriate operations, maintenance, and management personnel.

b. Observations and Findings

The inspectors determined that valve 3LP-22, which is in the line from the BWST to the 3B LPI pump, was to be painted as part of the material condition upgrade for all units. Material condition upgrade personnel

had placed the tape in preparation for painting the motor operator but were moved to other work before actually completing the painting. The use of this tape was not evaluated as part of the valve configuration nor did the painters specifically notify operations of this taping. The tape had been on the valve for three days before discovery by the inspectors.

The licensee stated that the work order controlling the painting had been signed by operations giving permission for the work to begin. However, shift operations personnel in Unit 3 were not aware of the work on 3LP-22 and the potential to affect its operability. Additionally, while the valve was located in a relatively open area with moderate traffic, no one reported the tape.

The licensee immediately removed the tape and initiated PIP 3-098-4178. Material condition upgrade personnel were instructed to discuss their work with operations on a daily basis. Prior to this they would only update operations on work status weekly. Operations management also issued a memo to shift personnel reminding them of the importance of monitoring the plant. The licensee's review of past operability on valve 3LP-22 indicated that there was enough thrust margin available for the valve to open or close with tape on the stem. The inspectors agreed with this analysis.

c. Conclusions

Poor communications between operations and material condition personnel resulted in tape remaining on the stem of an operable safety-related low pressure injection valve for three days. This was considered a weakness in communications between site organizations.

08 Miscellaneous Operations Issues (92901,92700)

08.1 (Closed) Inspector Followup Item (IFI) 50-269,270,287/95-03-01: Clarification of TS 3.3.1

(Closed) LER 50-269/90-15: Unit Operation In an Unanalyzed Condition Due to Design Deficiency, Design Oversight

This issue was originally described in IR 50-269,270,287/90-30. TS 3.3.1 requires only two HPI pumps to be operable below 60 percent power and three HPI pumps to be operable above 60 percent power. The licensee identified that under some accident scenarios below 60 percent power with a single failure, there could be insufficient flow with only two HPI pumps. The licensee reported this condition in LER 50-269/90-15 and established administrative controls to require three HPI pumps to be operable above 350 degrees F. This was left as Unresolved Item (URI) 50-269,270,287/90-30-01, Clarification of TS 3.3.1 pending completion of a TS change to revise TS 3.3.1 to clarify HPI system operability requirements.

In IR 50-269,270,287/90-34, the URI was dispositioned as a NCV with the URI remaining open. In IR 50-269,270,287/95-03, since the enforcement had occurred previously, the URI was closed and IFI 50-269,270,287/95-03-01 was opened. A TS submittal containing the administrative details was transmitted to NRC on March 31, 1997. Due to events involving the failure of the HPI pumps in April of 1997, the licensee committed to complete a reliability study for the HPI system. This study was to be completed by December 31, 1997. The NRC has requested additional information from the licensee and these efforts are being tracked through Technical Assignment Control (TAC) numbers: M98296, M98297, and M98298. The inspectors reviewed the documentation cited above and discussed the issue with NRC management.

Based on the licensee's submittal of the TS change, the tracking and review of the submittal by NRR, and the administrative controls in place to require three HPI pumps to be operable above 350 degrees F, this IFI and associated LER are closed.

The licensee's activities involving the TS change and administrative controls in place to require three HPI pumps to be operable above 350 degrees Fahrenheit (F) were considered adequate.

08.2 (Closed) Violation (VIO) 50-269,270,287/97-05-02:Failure to Maintain Configuration Control

The bolts for the RB emergency sump covers, for all three units were found missing. The licensee's root cause analysis, discussed in PIP 0-097-0146, determined the cause to be a lack of guidance regarding the bolts in the maintenance procedure. Also, it was determined that a lack of all bolts did not make the screen inoperable. Maintenance procedure, MP10A/1800/105, Revision 08, Reactor Building Emergency Sump LPI Suction Line Flange - Installation, Removal, and Screen Inspection, was clarified. The procedure was changed to require at least 4 bolts to be installed and tightened in a diagonal pattern. The analysis performed to ascertain operability, causes of discovery and resolution were timely and complete.

The corrective actions presented in the licensee's response, dated August 18, 1997, were verified by the inspectors. This violation is closed.

08.3 (Closed) VIO 50-269,287/97-15-01: Failure to Complete Required TS Surveillance on LPI Flow Instruments

(Closed) LER 269/97-09-00: LPI Flow Instrument TS Surveillance Interval Exceeded Due to Deficient Work Practices

On October 10, 1997, the licensee discovered that the last time the LPI flow instrument surveillance, required by TS Table 4.1-1 was performed, the flow transmitters were omitted from the surveillance. The surveillance was immediately performed which restored operability and met the TS. The licensee issued LER 269/97-09-00 on November 11, 1997,

and the NRC issued VIO 50-269,287/97-15-01, on December 15, 1997.

The corrective actions presented in the licensee's response to the violation, dated January 15, 1998, and the action described in the LER were reviewed and verified by the inspectors. The corrective actions included a review of 615 previously completed work orders to determine if this type of error has been made in the past. No similar errors were detected. The licensee also clarified the wording within the model work order used to schedule and complete these TS required calibrations. The discovery and subsequent corrective actions for a failure to perform a LPI flow instrument surveillance were timely and thorough. This violation and LER are closed.

08.4 (Closed) VIO EA 96-478-01014: Failure to Properly Install Main Steam Safety Valve (MSSV) Spindle Nut Cotter Pins

In response to an event at another nuclear power station, the licensee conducted an inspection of the MSSVs on all three units. Results of these inspections were reported in NRC IR 50-269,270,287/96-16, and in LER 50-270/96-05-01, Potential Uncontrolled Release via Main Steam Relief Valves Due to Inadequate Work Practices.

The corrective actions presented in the licensee's response, dated January 23, 1997, and in the LER were verified as completed. PIP 0-096-1599 was prepared to document the inspection results and PIP 0-096-2031 was written to perform root causes of the incorrectly installed cotter pins.

After the cotter pins were correctly installed on the MSSVs, a modification was made to remove the fork levers, spindle nuts, and cotter pins on all relief valves. This modification was expanded to include the primary relief valves on the pressurizer.

The modification eliminates the possibility of a relief valve failing to reset due to an improperly installed cotter pin. The modification was completed on the MSSVs for all three units and has been completed on the Unit 1 and 2 pressurizers, and the spare pressurizer relief valves. The work is scheduled to be completed during the next outage on Unit 3.

Following the recognition of the significance of the problem, the licensee took prompt and thorough corrective measures.

Violation EA 96-478-01014 is closed.

08.5 (Closed) LER 50-269/97-08-00: Manual Reactor Trip Due to Equipment Failure While Shutdown

This LER describes an event whereby the operators manually tripped the reactor protective system while the unit was at hot shutdown and sub-critical. The manual trip was required by procedure upon failure of main feedwater.

The plant systems and operators responded as expected. PIP 1-097-202 was issued on July 7, 1997, to investigate and correct the failure. The root cause was determined to be a failure of a circuit board in the main feedwater pump turbine control system. The recognition and response by the operators to a failure of main feedwater while shutdown, were considered timely and thorough. This LER is closed.

08.6 (Closed) LER 50-270/97-02-00: Grid Disturbance Results in Reactor Trip Due to Manufacturing Deficiency

On July 6, 1997, Oconee Unit 2 was operating at 100 percent power when a system grid disturbance initiated a generator protective relay actuation that resulted in all four reactor coolant pump monitor channels of the reactor protective system tripping. The operators placed the unit in stable, hot shutdown condition. The grid disturbance was created by a switching problem at Jocassee Hydro Station. The voltage regulator on Unit 2 did not respond an expected. The root causes of this event were determined to be a manufacturing deficiency and inadequate installation instructions. Corrective action included calibration of the voltage regulator. The resolution and corrective action in response to an inadequate procedure for voltage regulator adjustment were timely and thorough. Given that the voltage regulator is not subject to Appendix B, this will not be subject to enforcement action. This LER is closed.

08.7 (Closed) VIO EA 97-298-04014: Failure to Follow Operations Procedures Relating to Low Temperature Overpressure Protection Requirements

(Closed) VIO EA 97-298-03014: Failure to Follow Operations Procedure During the Unit 3 Cooldown on May 3, 1997

(Closed) VIO EA 97-298-05014: Failure to Follow Maintenance Procedures for the Installation of Tubing

(Closed) LER 50-287/97-03-00: High Pressure Injection System Inoperable Due to Design Deficiency and Improper Work Practices

The licensee's corrective actions for these violations were described in a letter dated September 25, 1997. The licensee's investigation and initial corrective actions were previously verified to have been satisfactorily performed during an inspection documented in IR 50-269,270,287/97-08. The LER also described the event and provided corrective actions. During this inspection, the inspectors verified that the corrective actions for the violations listed above and the LER had been completed. The licensee's analysis and resolution of the issues related to the HPI event were timely and thorough. The violations and the LER are 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 98067264 — Replace AT-7 Signal Isolator for 2NI-1
- IP/0/A/0301/3A-1 — NI-1 Neutron Flux Instrument Calibration (Unit 2), Revision 21
- IP/0/A/0301/3S-1 — Source Range and Intermediate Range Channel Test (Unit 2), Revision 26
- TT/1/A/0110/019 — Penetration Room Ventilation System 1A Pitot Tube Flow Test, Revision 0
- OP/1/A/1104/019 — Reactor Building Spray System, Enclosure 3.2, Removing Reactor Building Spray From ES Standby Mode, Revision 4
- OP/1/A/1104/004 — LPI System, Enclosure 3.1, RCS Cooldown Using LPI High Pressure Mode, Revision 80
- OP/0A/1106/019 — Keowee Hydro Operation From Oconee, Revision 43, Enclosure 3.1, Automatic Startup, Enclosure 3.4 Shutdown
- PT/0/A/0620/009 — Keowee Hydro Operation, Revision 16
- IP/0/A/0250/001C — Low Pressure Service Water to RCP Motor Coolers Low Pressure Injection Decay Heat Coolers and RB Component Coolers, Revision 7
- IP/0/A/0100/001 — Controlling Procedure for Electrical and I&C Troubleshooting and Corrective Maintenance, Revision 14
- PT/2/A/0261/010 — Essential Siphon Vacuum System Test, Revision 001
- PT/0/A/0251/010 — Auxiliary Service Water Pump Test, Revision 42
- OP/3/A/1104/10 — Filling Reactor Building Auxiliary Fan Coolers, Revision 58, Enclosure 3.23

- PT/3/A/0152/013 Low Pressure Service Water Valve Stroke Test Revision 5
- IP/0/A/0310/07C Engineering Safeguards System Logic Test - Channel 5 (3LPSW-565), Revision 27
- PT1&2/A/0110/015 Control Room Pressurization Test, Revision 11
- WO 98079105-01 Check Control Rod Drive Power Supply
- IP/0A/0310/08C Engineering Safeguards System Logic Test - Channel 6 (3LPSW-565), Revision 24

b. Observations and Findings

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. The inspectors frequently observed supervisors and system engineers monitoring job progress. Quality control personnel were present whenever required by procedure. When applicable, appropriate radiation control measures were in place.

c. Conclusion

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

M1.2 Station Auxiliary Service Water (ASW) Pump Impeller Replacement

a. Inspection Scope (62707)

On September 3, 1998, the inspectors observed portions of the impeller replacement and subsequent testing of the station ASW Pump.

b. Observations and Findings

In June 1998, the inspectors observed, after previous maintenance, that the packing follower nuts on the station ASW pump were not fully engaged. In response to inspectors questions regarding this thread engagement, the licensee decided to replace the packing follower nuts as part of the work order for changing the impeller. This decision was made after the work order had been issued and the work order was not revised to include the increased scope of work. The licensee's mechanics indicated that they believed the instruction being used contained sufficient direction.

On September 3, 1998, before the post-maintenance test was performed, the inspectors observed that the packing follower was slightly cocked, the packing follower nuts did not fully span the retaining holes in the follower, and the studs appeared to have been backed out in order to give the proper thread engagement on the nuts. Following questions by

the inspectors and observed leaks during the post-maintenance test, the licensee decided the packing follower was not completely in the stuffing box. They stopped the pump, removed one ring of packing, installed the packing follower farther into the stuffing box, and added washers underneath the packing follower nuts. They then tested the pump again and its performance was acceptable.

Removing one ring of packing resulted in the studs being fully engaged. The licensee later explained that the packing follower was initially installed in the stuffing box without cocking but the follower nuts only finger tight. They stated that, due to past problems with packing break-in, they intended to make packing adjustments during testing. The licensee acknowledged that the packing follower was cocked but that it was most likely caused by static pressure against the packing when the pump was filled for testing.

The impeller and follower nuts were replaced using procedure MP/0/A/1300/011, Pump - Ingersoll-Rand - Auxiliary Service Water Rotating Assembly - Removal, Repair And Replacement, Revision 14. The inspectors reviewed this procedure and found it contained one step to install packing, packing follower, and follower nuts. The procedure contained no guidance about packing follower alignment, the type of nuts and washers to use, or about thread engagement. Procedure MP/0/A/1300/010 Pump - Packing and Adjusting Packing, Revision 14, contained some of this guidance but only as a note dealing with how the packing should look when finished. The inspectors reviewed the pump vendor manual and found that it also did not contain any guidance about packing follower alignment, the type of nuts to be used, or the need for washers. It also did not contain any instructions on the installation of the follower studs. The licensee stated that the missing guidance did not affect the operability of the pump and addressed the type of material for the follower nuts and washers in PIP 0-098-4212.

Pending NRC review of the adequacy of procedures used on the station ASW pump, the material controls for parts used on the pump, and the work control requirements for the change in job scope, this item will remain unresolved. This will tracked as URI 50-269,270,287/98-08-01: Configuration Control of the Station ASW Pump.

c. Conclusions

Due to potential procedural and work control problems, packing practices on the safety-related station auxiliary service water pump showed a lack of attention to detail. This item was left unresolved pending additional NRC review of pump packing procedures, material controls, and work control requirements.

M3 Maintenance Procedures and Documentation

M3.1 Inservice Inspection (ISI) and Steam Generator Program Review (Unit 3)

a. Inspection Scope (73753)

The inspectors reviewed the licensee's program and plans for ISI and steam generator inspections during the Fall 1998, Unit 3 refueling outage.

b. Observations and Findings

The Fall 1998 refueling outage will be the end of fuel cycle number 17 (EOC17) for Unit 3. In the ISI schedule, this will be the first outage in the second 40-month period of the third 10-year inspection interval. The ISI American Society of Mechanical Engineers (ASME) Code of record for the second interval is ASME Section XI, 1989 Edition with No Addenda.

The inspectors reviewed the ISI program, including the incorporation of relief requests and ASME Code Cases that had been approved by the NRC. The inspectors found that the inspection plans for the Unit 3 EOC17 outage appeared to be complete.

The inspectors also examined the nozzle mock-up used to qualify procedures and personnel for the ultrasonic examination (UT) of the HPI nozzle inner radius area. The mockup was a full-scale representation of the actual in-plant installation, with an inside-surface defect in the nozzle inner radius. The inspectors agreed that the use of the mock-up would provide meaningful training for UT examiners.

The inspectors reviewed the estimated work scope for steam generator inspections planned for the Unit 3 EOC17. The planned examinations appeared to be comprehensive, examining all of the critical locations of the Once Through Steam Generators (OTSGs).

c. Conclusions

The licensee's plans for inservice inspection and steam generator examinations during the Fall 1998, Unit 3 refueling outage were comprehensive.

M8 Miscellaneous Maintenance Issues (92902,92700)

M8.1 (Closed) LER 50-269/97-11-00: Steam Generator Leak Results in TS Unit Shutdown Due to Inadequate Process Control

The subject of this LER was discussed in Section M1.4 of IR 50-269,270,287/97-18. The completion of the licensee's root cause investigation and issuance of the LER did not provide additional information over what was discussed earlier. This LER is closed.

M8.2 (Closed) LER 50-270/98-01-00: Operation With Steam Generator Tube Indications In Excess of Limits Due to Manufacturing Error

The subject of this LER was discussed in Section M1.3 of IR 50-269,270,287/98-05. The completion of the licensee's root cause investigation and issuance of the LER did not provide additional information over what was discussed earlier. This LER is closed.

M8.3 (Closed) LER 50-287/97-02-00: Reactor Building Cooling Units Technically Inoperable

(Closed) LER 50-287/97-02-01: Reactor Building Cooling Units Technically Inoperable Due to a Manufacturing Deficiency

This event was discussed in IRs 50-269,270,287/97-02 and 50-269,270, 287/97-12. No new issues were revealed by the LER. This LER is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Oconee Safety-Related Designation Clarification (OSRDC) Program

a. Inspection Scope (37550,40500)

The inspectors reviewed the licensee's OSRDC program and compared the current status with the program schedule and content commitments that had been described to the NRC in meetings and letters.

b. Observations and Findings

The licensee had described the schedule and content for the OSRDC program to the NRC in meetings on February 6 and May 1, 1995; in a letter dated April 12, 1995, titled "Oconee QA-1 Licensing Basis and Generic Letter 83-28, Section 2.2.1, Subpart 1 Supplemental Response;" and during bimonthly meetings on the Oconee Recovery Plan in 1997 and 1998.

The OSRDC program schedule, as described in the meeting of May 1, 1995, included completion by January 1997. However, the OSRDC program had not been completed in 1997 and it was then included in the Oconee Recovery Plan. The September 15, 1997, Oconee Recovery Plan schedule for OSRDC program completion was November 1, 1998. The most recent (June 30, 1998) Oconee Recovery Plan schedule for OSRDC program completion was January 1999.

The inspectors verified the licensee was currently on track for OSRDC program completion by January 1999. The licensee had 12 engineers working on the program (one onsite and 11 in Charlotte) and expressed a determination to meet the January 1999 completion schedule. In comparison, the licensee had about four engineers working on the OSRDC program during 1995-1997. Also, higher priority programs and projects

had impacted the OSRDC program schedule during that time. During 1995-1997, the 20-month OSRDC program had fallen over 22 months behind its original schedule. The inspectors concluded that, during 1995-1997, the licensee had been ineffective in keeping the OSRDC program on schedule. However, during the increased oversight in 1997-1998, the licensee had essentially kept the OSRDC program on its revised schedule.

As described in the May 1, 1995, meeting summary, the OSRDC program was designed to provide additional maintenance and testing to non-safety equipment that was relied upon to mitigate design basis accidents. At Oconee, quality assurance requirements for systems, structures, and components (SSCs) have been addressed separately from design requirements. The terms safety-related and quality assurance (QA) category QA-1 were used interchangeably. QA-1 SSCs, as listed in UFSAR Chapter 3.3.1, must meet 10 CFR 50, Appendix B, quality assurance requirements. The OSRDC program included identifying all SSCs relied upon to mitigate approximately 25 design basis accidents and determining which of those SSCs were not already designated as QA-1. Those non-QA-1 SSCs that did not operate during normal plant operation in the same mode that they would function during an accident would be designated as QA-5. QA-5 SSCs would then be given maintenance and testing of similar quality as that given to QA-1 SSCs.

The inspectors verified that the licensee had completed the listing of SSCs relied upon for almost all of the design basis accidents, and had not yet determined which of those SSCs were not designated as QA-1. The information was assembled in a computerized database with 11 columns including: Event, Component Identification, Drawing, Operation (required action), Actuation Method, Notes (further describing the required action), System Function, Related Indication, and Associated Components. The database was capable of sorting and printing the information in various ways. The inspectors noted that some of the level of detail in the data was good in that related indication and associated components were included. However, some equipment was notably missing such as electrical power supplies (e.g., breakers and relays). Licensee engineers stated that they planned to add electrical components to the database.

c. Conclusions

The inspectors concluded that, while the OSRDC program was two years behind its original completion schedule of January 1997, the licensee had essentially kept the OSRDC program on its revised schedule during the last 11 months. Some of the level of detail in the partially completed database of components relied upon to mitigate accidents was good, in that related indication and associated components were included, and some equipment was notably missing such as electrical power supplies. Overall progress on the OSRDC program during the last year was adequate.

E1.2 Unit 1 RCP Problem Resolution

a. Inspection Scope (37551)

During the period, Unit 1 developed problems with two of the RCPs which culminated in a Unit 1 shutdown on August 8, 1998. The inspectors followed the engineering evaluation, resolution of these problems, and independently inspected the other RCPs.

b. Observations and Findings

1B1 RCP

PIP 1-98-3836 indicated that the 1B1 RCP had an oil leak (8 drops/minute) at a slight (1/32 inch height) mis-alignment of its two piece cover on the lower motor oil reservoir. The cover was distorted from the mis-alignment and had 1/16 inch gouges in the gasket seating area. A review of historical work orders (WO) revealed that a slight oil leak had been present for some time (WOs 96099135 and 97085335), and had not been resolved (inspectors reviewed the WOs). Both the WOs had been worked but the repair shop had reused the existing cover. The existing cover contributed to the leakage in that the distorted cover coupled with gasket seating area gouges reduced the effectiveness of the oil sealing joint. During the current repair, a spare aluminum cover was used to replace the existing cover thereby eliminating this contribution.

The licensee was also proceeding with the replacement of existing aluminum covers with steel covers in an effort to reduce distortion and leakage possible with the existing aluminum covers. This effort had been started before, but was abandoned. Visual inspections by the licensee and the inspectors revealed no other oil leakage on the other three RCPs.

The inspectors concluded that the lack of effective corrective action on the previously identified oil leak was a weakness. The pump reservoir is non-safety related equipment and not subject to enforcement.

1A2 RCP

The 1A2 RCP had an increasing leakage trend on its number one seal. On disassembly, the licensee discovered that the Teflon double seal delta channel seal (DSCS) had begun to deteriorate. The licensee had documented their review and evaluation under failure investigation process (FIP) in PIP 1-98-3832. The final process report was signed off August 26, 1998. The inspectors examined the DSCS, observed portions of the shaft seal disassembly and inspection, reviewed the report, and reviewed the pump vendor information on the probable cause.

During the Unit 1 startup, the inspectors observed that all seals behaved as expected and seal leak off values were within expected ranges. The evaluation for the problem was good and the inspection effort was methodical. The inspectors agree that the seal manufacturer information and facts tend to support the licensee's theory that the seals exhibited higher leakage rates as a result of two thermal

transients coupled with elevated RCS suspended solids, which occurred in late December 1997 and May 1998.

c. Conclusions

The repair practice on the non-safety related 1B1 RCP lower oil reservoir that had perpetuated a repetitive minor oil leak was poor. The leak from the reservoir was the reason for the Unit 1 shutdown this period. Engineering analysis of the current self-disclosing 1B1 RCP reservoir leak was good.

Engineering analysis of the self-disclosing 1A2 RCP pump seal problem was good.

E1.3 Emergency Power System Open Items and Commitments (Recovery Plan)

a. Inspection Scope (37551)

The inspectors reviewed the licensee's initiative involving the emergency power system open items and commitments with the NRC. This licensee initiative was part of the recovery plan. The scope of the initiative was to resolve several NRC open items and to close several commitments concerning the emergency power system.

b. Observations and Findings

The initiative contained ten line items consisting of the following: five items involving responses to violations; two items, commitments, provided a response to the interim Keowee report and the installation of electrical protection for Keowee; one item, a VIO and a related LER, documented corrective actions involving a Keowee event; one item, an IFI and an associated commitment, to install new ground detection equipment; and one item, an IFI, to complete the root cause evaluation for relay failures.

The licensee issued PIPs on the issues and performed failure identification process of selected PIPs concerning these items.

As a result of the review of the initiative, the inspectors determined the following: the five violations were being addressed in conjunction with applicable PIP forms and three of the items were associated with a FIP team report; the commitment involving the interim report was completed on June 18, 1998, and the protection commitment is to be implemented by Nuclear Station Modification (NSM) ON-53014; the violation and the related LER for the Keowee event were being addressed in conjunction with a PIP and were reviewed by the licensee using a FIP team report; the ground detection commitment is to be implemented by NSM ON-53004; and the IFI for the relay failures was being addressed by a PIP and was reviewed using a FIP team report.

The PIPs and the FIP team reports were in general well written; the problem identifications were easily understood, covered the individual

problem items, and listed related PIPs; the screening, operability, and reportability reviews referenced TS, quality classifications, and regulatory issues; the problem evaluations discussed the problem items extensively and throughly; the FIP team results were technically sound and showed good engineering judgement; and the corrective actions were comprehensive and addressed the individual problem items. The PIP corrective actions also contained, where applicable, the responses to the NRC open items.

The inspectors observed that the five violations were being prepared for NRC closure and the PIP corrective actions associated with the violations have been completed. The two modifications are scheduled for INN67, a non-refueling outage time frame, starting in November 1998.

c. Conclusions

The inspectors concluded that the use of the problem investigation process to track to closure corrective actions for NRC open items and commitments involving the emergency power system and the quality thereof were good.

The inspectors concluded that, at management direction, the use of the failure investigation process reports by engineering, when necessary, to address significant issues involving the emergency power system and the quality of the reports were excellent.

The inspectors concluded that the onsite engineering group was addressing the open items and commitments involving the emergency power system in a sound technical manner, with appropriate resources, using approved methods, and with management and supervisory oversight.

This Recovery Plan item is closed.

E1.4 Emergency Core Cooling System (ECCS) Pumps' Net Positive Suction Head (NPSH) and Containment Over Pressure Licensing Basis Assumption

a. Inspection Scope (92903,37550)

The inspectors reviewed the licensee's actions associated with a 50.72 reported condition of being outside the station licensing basis that was identified by the NRC while reviewing the licensee's response to GL 97-04, NPSH for Emergency Core Cooling and Containment Heat Removal Pumps, dated October 7, 1997. The licensee issued LER 50-269/98-011, Available NPSH for RBS Pumps Outside Design Bases Due to Incorrect Interpretation, on September 17, 1998, to document this issue.

b. Observations and Findings

The NRC's request for additional information letter to Duke Power - Oconee, dated August 11, 1998, identified that the licensee's response to GL 97-04, dated January 5, 1998, indicated a condition outside the NRC reviewed and approved licensing basis. This condition was that the

ECCS pumps NPSH analysis reviewed and approved in the licensing basis, as documented in the Safety Evaluation Report dated July 6, 1973, did not credit containment over pressure as an input in the determination of available NPSH for ECCS pumps during a design basis accident; whereas the revised licensee analysis in 1991 did credit containment over pressure to assure the available NPSH was adequate for the RBS pumps which are ECCS pumps. Containment over pressure is defined as that pressure which is the difference between actual containment building pressure and the vapor pressure due to containment sump water temperature.

In 1991, the licensee identified that RB over pressure was required to assure RBS pumps' operability. This was documented in calculation OSC-4361, RBS Pump NPSH Analysis, dated May 31, 1991. This calculation was performed when the licensee identified that the previous NPSH analysis used non-conservative design inputs in that the most restrictive flow path was not evaluated and an incorrect RBS pump NPSH requirement was used. The calculation concluded that a minimum of 2 psig RB over pressure was required to assure adequate NPSH for RBS pump operability. The calculation verified that adequate RB pressure was available as documented in calculation OSC-4240, UFSAR 15.14.5, LBLOCA Long Term Containment Response, dated March 19, 1991. It was not identified that this condition of crediting RB over pressure to assure RBS operability was inconsistent with the licensing basis. UFSAR Table 6-1, NPSH Available to ES Pumps During Recirculation, specified that adequate NPSH was available without crediting RB over pressure. The UFSAR was not updated to reflect the latest information.

In 1992, the licensee identified additional non-conservative design inputs and again evaluated the RBS NPSH requirements with respect to RB pressure. Calculation OCS-4467, RB Pressure Needed for RBS Pump Operation, dated March 9, 1992, determined a slightly higher RB pressure of 2.8 psig was required to assure RBS pump operability. The availability of this RB pressure was documented in OSC-4240 as stated above. The licensee again did not identify that credit for RB over pressure was inconsistent with the licensing basis. The UFSAR was not updated to reflect the latest information regarding NPSH and RB pressure requirements. The failure to update the UFSAR was a non-compliance with 10 CFR 50.71e which requires the UFSAR to be updated to assure the UFSAR contains the latest material developed. This 1991 and 1992 failure to update the UFSAR with this information does not reflect present licensee performance. Additionally, a comprehensive program was initiated in 1997 to review the accuracy and revise the UFSAR. In accordance with the Enforcement Policy, Section VII.B.3, a violation will not be identified for this non-compliance with 10 CFR 50.71e.

In a 1996 UFSAR revision, the licensee revised the ECCS NPSH accident analysis description to delete Table 6-1. All detailed reference to the available and required LPI and RBS NPSH values were deleted. This included the Table 6-1 information that specified that adequate NPSH was available for the RBS pumps without crediting RB over pressure. The related 10 CFR 50.59 evaluation, dated May 22, 1996, addressed the

change as an editorial change only and did not recognize the revised analysis was inconsistent with the licensing basis as described in the SER, dated July 6, 1973. Subsequently, the 50.59 evaluation response to the questions defining an unreviewed safety question (USQ) were incorrect. Specifically, the response should have been yes to item four regarding the increased probability of malfunction of equipment important to safety. The condition of crediting containment over pressure to assure RBS pump operability was not included in the NRC approved licensing basis, and was therefore an unreviewed safety question. This is identified as VIO 50-269,270,287/98-08-02: Inadequate 50.59 Safety Evaluation for 1996 UFSAR Revision Related to ECCS Pumps' NPSH Analysis.

A related issue identified by the licensee during this review was that the containment pressure assumed in the NPSH analysis at event initiation was not consistent with a containment pressure value in TS. It appeared that the negative .1 psig assumed in the analysis was less limiting than the negative 2.45 psig referenced in TS 3.6.4. This was addressed in PIP 0-098-3976. Revision 5 of Calculation OSC 4467, RB Pressure Needed for RBS Operation revision 5, was completed on August 31, 1998. The revised analysis used negative 2.45 psig and 80 degrees F as input to the model and determined that the initial conditions of negative 1 psig and 160 degrees as used in the previous analysis (revision 4) was more limiting for NPSH considerations. This condition was identified in the PIP as operable but degraded for the RBS pumps. Compensatory actions were implemented to assure the assumptions in the calculation were assured during plant operations. These actions included establishment of periodic surveillance for reactor building pressure and more restrictive values for boron water storage tank temperature and lake temperature. These were incorporated in procedure PT/1,2,3/A/0600/01, Periodic Instrument Surveillance, dated August 21, 1998. A 50.59 safety evaluation was documented for the compensatory actions in PIP 0-98-3976, dated August 21, 1998.

The licensee's actions to evaluate and initiate corrective actions following NRC identification of this USQ and the related TS RB pressure inconsistency issue were appropriate, timely, and consistent with the requirements of GL 91-18, Revision 1, Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming conditions. A 50.72 report was submitted on August 19, 1998. The operability was promptly evaluated and it was determined that adequate containment pressure was available during a LOCA to assure pump operability. This was documented in PIP 0-098-3889 dated August 11, 1998, and supported by Calculations OSC-6521, Containment Response with 30 Minute Delay in LPSW Flow, revision 3 and OSC-4467, RB Pressure Needed for RBS Operation, revision 5. These calculations demonstrated that containment pressure during a design base accident exceeded that pressure required for RBS operation. A license submittal was being developed to change the licensing basis to reflect the 1991 analyzed condition crediting RB over pressure for RBS NPSH determination. The LER report 50-269/98-011 was issued on September 17, 1998, and included

corrective actions taken and planned to correct the violation and prevent recurrence.

The primary contributor to this issue regarding the licensee being outside the licensing basis was that the licensee did not correctly identify the licensing basis condition in their interpretation of the SER, dated July 6, 1973. It was apparent in their January 5, 1998, response to GL 97-04 that they interpreted the licensing condition to include crediting containment over pressure. The ambiguity in the SER regarding the use of "over pressure" when addressing vapor pressure and the UFSAR Table 6-1 listing NPSH values which included containment over pressure could lead the evaluating engineers to incorrectly conclude that containment over pressure was an approved license condition. The documentation of the 1996 UFSAR revision 50.59 safety evaluation was limited and did not reference these documents. Additionally, as previously stated, the evaluation stated the UFSAR revision was primarily editorial; therefore, it is indeterminate to what extent the evaluator investigated the licensing basis.

c. Conclusions

A violation of 10 CFR 50.59 was identified for an inadequate safety evaluation that did not identify the USQ associated with being outside the licensing basis for LOCA accident analysis associated with RBS NPSH. The NRC concluded that information regarding the reason for the violation and corrective actions planned to correct and prevent recurrence were adequately addressed on the docket in LER 98-011, dated September 17, 1998. Although the licensee performance was poor in identifying the licensing basis related to this design base assumption, their performance was adequate in evaluating the operability of the RBS pumps in the revised design base condition. The licensee's evaluation demonstrated there was no safety concern related to this issue and no modifications were required to assure RBS pump operability.

E2 Engineering Support of Facilities and Equipment

E2.1 Corrective Action Program

a. Inspection Scope (40500)

The inspectors reviewed the licensee's corrective action program which was implemented by Nuclear System Directive (NSD) 208, Problem Investigation Process, Revision 18. Aspects of the process reviewed included significance screening, operability evaluations, cause determination, adequacy of corrective actions, and timeliness of corrective actions. A sample of approximately 100 PIPs were reviewed. The majority of the sample were Level 3, less significant event (LSE) PIPs, and a smaller number of Level 1 and Level 2, more significant event (MSE) PIPs, initiated in 1997 and 1998. The sample included both completed and in-process PIPs.

b. Observations and Findings

(1) Significance Screening

The criteria for determining the significance of PIPs were provided by directive NSD 208. A multi-organizational screen team evaluated each PIP for significance in accordance with these criteria during work week daily meetings. Many PIPs were conservatively categorized as Level 2 MSE PIPs initially to ensure that an operability evaluation was performed on those problems with potential operability impact. These PIPs were downgraded to LSE PIPs if no operability or reportability concerns were identified. Downgrading of PIPs was adequately controlled by the SRG. The inspectors' sample indicated that the licensee was effectively categorizing PIPs with respect to significance. One exception was noted related to a Level 3 LSE PIP (1-098-2616) which addressed repeated RCS sample valve failures. The criteria indicated that this PIP should have been categorized as a level two MSE PIP because it appeared to be an adverse trend. Overall, screening performance was generally good.

(2) Operability Evaluations

Operability evaluations were adequate to determine the impact on equipment and system operation. The inspectors noted that the operability justification was routinely documented in the problem evaluation section of the PIP rather than in the designated operability section.

(3) Cause Determinations - Corrective Actions

Level 3 LSE PIPs received a less rigorous cause determination than MSE PIPs and the documentation was generally less detailed. The inspectors assessed cause determinations by the adequacy of the assigned corrective actions for these PIPs. In the sample reviewed, the corrective actions were appropriate to address the identified problem. Cause determinations for the MSE PIPs reviewed were adequate and assigned corrective actions were appropriate. The timeliness of corrective actions was addressed in the review of the PIP backlog.

(4) PIP Corrective Action Backlog

The inspectors reviewed the timeliness of PIP corrective actions relative to the impact on the PIP corrective action backlog. The PIP corrective action backlog was one of the initiatives discussed in the Oconee Recovery Plan under the Management Focus Area of Self-Assessment. During review of the PIP corrective action backlog, the inspectors noted that the licensee's stated goal in the Oconee Recovery Plan was to reduce the number of PIP corrective actions greater than six months old from over 500 in August 1997 to less than 200 by December 31, 1998. The licensee's performance indicators in the Oconee Recovery Plan showed that at the end of July 1998, there were 232 PIP corrective actions greater than six months old. The 232 PIP corrective actions were in

line with the licensee's target of 240 by the end of July 1998. During further review of this initiative, the inspectors noted that there were other licensee performance indicators of open PIP corrective actions which were not discussed in the Oconee Recovery Plan. There was also a category of PIP corrective actions designated as management exception. The performance indicators showed that there were 428 PIP corrective actions in the management exception category that were greater than six months old. The inspectors questioned why the PIP corrective actions in the management exception category greater than six months old were not included in the PIP corrective action backlog discussed in the Oconee Recovery Plan. Licensee management stated that the PIP corrective action backlog did not include management exception items because the management exception items did not meet the licensee's definition of what was considered to be a backlog item. The inspectors concluded that there was a weakness in the PIP corrective action backlog discussed in the Oconee Recovery Plan in that it was not an accurate reflection of the overall backlog of PIP corrective actions at Oconee.

c. Conclusion

Screening of PIPs was good in that the significance was appropriately identified. Downgrading of PIPs was adequately controlled. Operability evaluations of the identified problems were adequate. Cause determinations and assigned corrective actions were adequate. The PIP corrective action backlog, as stated in the Oconee Recovery Plan, provided an unclear and inaccurate assessment of the overall PIP corrective action backlog. Specifically, the recovery plan stated that there were 232 open PIP corrective actions greater than six months old, while other performance indicators showed the actual number was approximately 660 (which included 428 management exception items) open PIP corrective actions.

E7 Quality Assurance in Engineering Activities

E7.1 Self-Assessment Activities

a. Inspection Scope (40500)

The inspectors reviewed selected licensee initiatives in the Oconee Recovery Plan under the management focus area of self-assessment. These initiatives included Corrective Action PIP Backlog (discussed in Section E2.1 of this inspection report), PIP Quality, Manager Observation/Group Assessment Effectiveness and Benchmarking, and Enhance SRG Self-Assessment Processes.

b. Observations and Findings

(1) PIP Quality

The purpose of this initiative was to raise the level of PIP quality by having the SRG review closed PIP activities for compliance with Directive NSD 208 and reopen those PIP reports where improvements were

needed. The inspectors reviewed several SRG assessment reports and noted that the SRG has been identifying areas for improvement in the PIP process. The SRG has been providing the results of their reviews and feedback to the responsible organizations and to plant management. The SRG also updated the Oconee PIP data base to provide additional guidance to PIP report preparers for those areas identified in the assessments as needing improvements. These efforts by the SRG have contributed to the reduction in the percentage of PIPs being rejected from approximately 24 percent in August 1997, to approximately 9 percent in July 1998.

The inspectors concluded that the PIP quality reviews performed by the Safety Review Group were effective in identifying areas for improvement in the PIP process.

(2) Enhance SRG Self-Assessment Processes

The purpose of this initiative was to improve the structure of the Independent Nuclear Oversight Team (INOT) based on the Safety Assurance strategic study. The INOT included SRG members for each of the NRC systematic assessment of licensee performance (SALP) functional areas. The INOT was performing in-plant reviews of activities based on the NRC SALP functional areas. The inspectors reviewed some of the milestones established in the Oconee Recovery Plan for this initiative. All INOT members were transferred to the SRG by the established date of June 1, 1998. However, the operations SALP area SRG member returned to operations. Actions to replace the operations area SRG member were in progress at the conclusion of this inspection. The inspectors reviewed the Oconee 1998 assessment schedule (which included SRG in-plant reviews) and noted that SRG in-plant reviews were being performed in accordance with established schedules. The inspectors also noted that the programs and directives under which the INOT will function (including INOT roles and responsibilities) were being revised and/or developed to reflect the current SRG organization.

The inspectors concluded that in-plant reviews were being performed in accordance with established schedules. However, programs and directives under which the INOT will function were still in the process of being revised to reflect the SRG organization (including the INOT roles and responsibilities).

E7.2 Licensee Safety System Engineering Audit (SSEA) of Emergency Feedwater (EFW)

a. Inspection Scope (37550,40500)

The inspectors reviewed the licensee's SSEA of EFW to assess the inspection scope and findings.

b. Observations and Findings

The inspectors found that the licensee's SSEA of EFW had an appropriate scope, which was similar to the scope of an NRC Safety System

Engineering Inspection. The SSEA final report included some good findings (e.g., numerous calculation deficiencies and drawing errors which the licensee evaluated as having no impact on the calculation conclusions or on system operability). Also, the inspectors verified that the SSEA findings and recommendations were appropriately entered into the licensee's corrective action system for resolution. All of the SSEA findings were appropriately assessed by the licensee as less significant issues, for which no operability evaluation was needed. However, the inspectors noted that the SSEA may have missed some significant issues. (See Section E8.1 of this report for potential EFW design issues raised by the inspectors.) The SSEA also failed to identify an incorrect statement in the UFSAR that stated that once started, the EFW pumps would continue to run until stopped by an operator. The UFSAR statement overlooked an automatic trip of the turbine-driven EFW Pump at a low OTSG pressure of 500 psig. The inspector noted that the licensee's UFSAR review project had also missed the EFW design issues and UFSAR error. Therefore, the overall inspector assessment of the licensee's SSEA of EFW will not be completed until the significance of these inspector-identified potential design issues is resolved.

c. Conclusions

The licensee's EFW SSEA had an appropriate scope and included some good findings (e.g., calculation deficiencies), but both the SSEA and the UFSAR review project missed some significant issues. The overall inspector assessment of the EFW SSEA will not be completed until the significance of inspector-identified potential design issues is resolved.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Open) URI 50-269,270,287/98-03-09: Licensing Basis Issues With Single Failure and QA For Non-Safety Equipment Required To Mitigate An Accident

a. Inspection Scope (92903.37550)

This URI was opened for further NRC review of licensing basis issues with single failure vulnerabilities and quality assurance for non-safety equipment that was relied upon to mitigate a design basis accident. The inspectors reviewed the OSRDC Program and its treatment of quality assurance and single failure.

b. Observations and Findings

The inspectors found that the licensee's OSRDC Program was identifying non-safety equipment that was relied upon to mitigate a design basis accident and addressing quality assurance treatment of that equipment (in the form of maintenance and testing). The OSRDC Program was not looking for or in any way addressing single failure vulnerabilities.

The inspectors also found that the equipment that was designated QA-1 (which meant that 10 CFR 50, Appendix B was applicable) was not necessarily the same equipment that was included in various programs to improve safety; such as single failure, seismic, environmental qualification (EQ), GL 89-10 motor-operated valve (MOV) testing, Regulatory Guide (RG) 1.97 instrument qualification, in-service testing (IST), preventive maintenance (PM), TS, or probabilistic risk assessment (PRA). To better understand the application of design standards and programs at Oconee, the inspectors selected 31 components that were relied upon to mitigate design basis accidents and then reviewed whether they had been included in these programs.

QA-1

In selecting the 31 components for review, the inspectors tried to include some that should have been classified as QA-1 and some that likely were not QA (10 CFR 50, Appendix B did not apply). The inspectors also included several components that were in the EFW system, to gain some knowledge of that system to use in part as a basis for evaluating the licensee's current EFW SSEA. After further review, the inspectors found that approximately half (16) of the 31 components selected were QA-1 and approximately half (15) were not fully QA. This supported the previous licensee and NRC assessments that many components that were relied upon to mitigate design basis accidents were not in a QA program. The 31 components and their QA status were as follows:

Component	QA Status
1) Turbine-Driven Emergency Feedwater (FDW PU-003)	Not Fully QA (Lubricating Pump Oil System Not QA)
2) Motor-Driven EFW Pump (FDW PU-004)	QA-1
3) EFW Flow Control Valve (FDW VA-315)	Not Fully QA (Air Operator and Air Supply Not QA)
4) FDW VA-315 Manual Loader (FDW ML-0046) (for manual operation from the control room)	Not QA
5) EFW Minimum Flow Bypass Valve (FDW VA-370)	QA-1
6) Main Feedwater Pump Hydraulic Oil Pressure (FDW PS-0382) (used to autostart EFW)	QA-1
7) Motor-Driven EFW Pump From Upper Surge Tank (UST) Suction Isolation Valve (C VA-573)	QA-1

8) Turbine-Driven EFW Pump From Hotwell Suction Isolation Valve (C VA-391)	QA-1
9) EFW Cross-Tie Valve (FDW VA-0313) (to get EFW from other units)	QA-1
10) Condenser Hotwell Emergency Makeup Valve (C VA-0187) (dumps UST to hotwell)	QA-1
11) Main Condenser Vacuum Breaker Valve (V VA-186)	Not QA
12) UST Level Transmitter (C LT-0015A)	QA-1
13) UST Level Indicator (C P-0081)	QA-1
14) Condenser Hotwell Level Transmitter (C LT-0019A)	Not QA
15) Control Room Ventilation System (CRVS) Outside Air Damper CD-10A	Not QA
16) CRVS Booster Fan AH-26	Not QA
17) CRVS Radiation Monitor (RIA RT-0039)	Not QA
18) Letdown Storage Tank Level Transmitter (HPI LT-0033)	Not QA, but Modification Scheduled to Upgrade to QA-1
19) Caustic Pump (CA PU-004)	Not QA
20) Caustic System Valve (CA VA-0039)	Not QA
21) Main Turbine Stop Valve (MS VA-0102)	QA-1
22) Main Turbine Stop Valve Trip Solenoid Valve Not (EHC SV-1083)	QA-1
23) Main Feedwater Flow Control Valve (FDW VA-0032)	Not Fully QA (Air Operator and Air Supply Not QA)
24) Main Feedwater Block Valve (FDW VA-0031)	Not QA
25) Main Steam Pressure Transmitter (MS PT-0277)	QA-1
26) Steam Generator 'A' Level Transmitter (FDW LT-0080)	QA-1

27) Steam Generator Shell Temperature Indication (FDW IOA-0972)	Not QA
28) Steam Generator Level Control System (SGLCS)	QA-1
29) Main Steam Isolation Logic Manual Switch (S-1016)	QA-1
30) Steam Generator Atmospheric Dump Valve (MS VA-0162)	Not QA
31) Block Valve for Steam Generator Atmospheric Dump Valve (MS VA-0153)	QA-1

The inspectors found that the licensee's basis for designating components as QA-1 was not based on safety function, but instead was based on being designated as QA-1 equipment in Chapter 3 of the UFSAR. The inspectors further reviewed components that were not QA and that were either: 1) relied on in a system that was described in the UFSAR as safety-related and QA-1 or 2) vulnerable to single failure. The inspectors assessed components as vulnerable to single failure if the single active failure of a component would challenge the system design basis or the accident mitigation strategy. Those non-QA components that were further reviewed are discussed under Single Failure below.

Single Failure

The inspectors assessed that 11 of the 31 components were vulnerable to single failure. Two of the 11 were also in a system that was described in the UFSAR as safety-related and QA-1. Those 11 components included:

1) An air-operated 12-inch valve in a 20-inch line that dumped UST water to the main condenser hotwell, C-187. Since the UST was the suction source for all EFW pumps, the inspectors noted that a failure open of C-187 could result in a rapid loss of all UST water and a consequent loss of EFW. Each Oconee unit had a hotwell level transmitter that, on a low hotwell level, would automatically open valve C-187 to dump water from the UST to the hotwell. However, at a UST level of seven feet, the hotwell level signal would be overridden by a UST level signal and C-187 would go closed to protect sufficient UST water to supply the EFW pumps. C-187 would also fail closed on a loss of instrument air. Valve C-187 was QA-1 and seismic, was not in a harsh environment (EQ was not applicable), was in the IST program, was in a PM program, was not in TS or selected licensee commitments (SLC), and was in the PRA. The potential untimely dumping of the UST to the hotwell, due to the failure open of C-187 during a main feedwater line break, was identified in the PRA as a significant contributor to the probability of a loss of all EFW.

The UFSAR stated that the EFW system could withstand a single failure coincident with a secondary pipe break and a loss of offsite power. However, the PRA apparently contradicted the UFSAR when it stated that a single failure of C-187 coincident with a main feedwater line break would cause a loss of all EFW. Also, the inspectors found that a 1973 licensee report to the NRC on high energy line breaks outside containment stated that a main feedwater line break in the turbine building would cause a loss of all main feedwater, a loss of all EFW, and also may cause a loss of 4160-volt switchgear 1TC, 1TD, and 1TE. These 4160-volt switchgear were the three trains of safety-related power to the motor-driven EFW pumps and also to engineered safeguards equipment including high pressure injection pumps, low pressure injection pumps, building spray pumps, and low pressure service water pumps. The inspectors noted that, in addition to apparently contradicting the UFSAR, this information did not seem to be reflected in the PRA. The 1973 report was still the analysis of record for main feedwater line break and was currently referenced in the FSAR. (Note: Main feedwater line break was not a licensed design basis event and was not discussed in the accident analysis chapter of the UFSAR.)

In response to concerns about the potential inability of the EFW system to withstand a main feedwater line break or a single failure coincident with a secondary pipe break, the licensee initiated a PIP to review the issue. The inspectors plan to follow up on this issue.

2&3) An air-operated EFW flow control valve, FDW-315, and the manual loader for control room operation of that valve. Each Oconee unit had two EFW flow control valves, one in the discharge piping from each motor-driven EFW pump. During certain events, including a main steam line break, operators were to immediately throttle EFW flow to prevent damage to the EFW pumps. As a result of low pump discharge pressure that could result from a main steam or feed line break, two of the three EFW pumps could have insufficient NPSH: the safety-related motor-driven pump that supplied water to the affected OTSG and the non-safety related turbine-driven pump, which supplied water to both OTSGs. The EFW system design basis included the ability to respond to a design basis event (e.g., main steam line break) coincident with a single failure and a loss of offsite power. If two EFW pumps could be damaged due to the event, the EFW system would not be able to then withstand a single failure of the remaining EFW pump. For a main steam line break inside containment, operators were also relied upon to manually stop EFW flow to affected OTSG within 10 minutes to prevent overpressurizing the containment. There was a motor-operated valve in the discharge piping from each motor-operated EFW pump that the operators could close from the control room to stop EFW flow. However, the inspectors considered the operator action to throttle EFW a type of single failure vulnerability because one

operator could be relied upon to correctly perform all of the required manual actions.

The EFW system was described in the UFSAR as safety-related and QA-1. The EFW flow control valve bodies were QA-1 and seismic. The air operators were not QA-1 but were seismic. The manual loaders and instrument air supply to the valve operators were not QA-1 or seismic. A two-hour supply of nitrogen, to assure the ability to operate the valves from the control room, was not QA-1 and was not seismic. However, the licensee had committed to the NRC in 1987 to walk down the nitrogen supply lines and verify that they would withstand a seismic event. The valves were EQ, were in the IST program, were in a PM program, were in the TS, and were in the PRA. The manual loaders were not QA or seismic, but were included in the licensee's Seismic Qualification Users' Group (SQUG) program. (See Seismic below for a description of the SQUG program.) An inspectors' walkdown reviewing the seismic ruggedness of the nitrogen supply lines to the EFW flow control valves is documented in Section E8.7 of this report. The loaders were not in a harsh environment, were in a PM program, were in the TS, and were in the PRA. The PRA described the operator action to immediately throttle EFW flow (using the EFW flow control valves and manual loaders) as a significant contributor to the probability for the loss of all EFW.

During a walkdown of portions of the EFW system, the inspectors observed that operator access to the handwheel of Unit 3 EFW flow control valve FDW-316 during an event would involve the operator climbing off a platform, over a handrail, and walking about 6 feet on a horizontal pipe that was about 15 feet above the floor. (The platform did not go to the valve and there was no room to use a ladder.) The air operator for FDW-316 was non-safety related, and the licensee had documented to the NRC that operators could readily operate the valve by handwheel during an event. An operator and the Operations Superintendent stated that, during an event, plant safety would take priority over personal safety and the operator would walk on the pipe to access the handwheel. The inspectors noted that this design condition, that placed operators in the position of jeopardizing personal safety to support plant safety during a design basis event, had existed in the plant for many years without the licensee identifying it. In response to this inspectors concern, the licensee initiated a PIP on this issue. The inspectors plan to follow up on the licensee's resolution of operator access to FDW-316.

The inspectors found that a licensee analysis concluded that the EFW pumps, that were feeding an OTSG affected by a steam line break, could experience insufficient NPSH or pump runout in less that one minute as a result of rapid depressurization of the OTSG to less than about 500 psig. Licensee personnel stated that, based on training simulator drills, they had concluded that operators could be relied on to throttle EFW within three minutes

during a main steam line break event. Licensee personnel also stated that they had no valid test or other data to support their contention that the EFW pumps could operate for several minutes with insufficient NPSH without suffering damage. The inspectors noted that the NRC typically has not approved reliance on simple operator actions (e.g., turning a switch in response to an alarm) in less than 10 minutes or reliance on complex operator actions (e.g., throttling flow to a specified value as read on a meter) in less than 20 minutes, to mitigate design basis events. The NRC also has not typically approved reliance on operating multiple stage pumps (like the EFW pumps) with insufficient NPSH, to mitigate design basis events.

The inspectors found that the reliance on operating the EFW pumps with insufficient NPSH had been identified as the most important finding of a 1987 NRC Safety System Functional Inspection (SSFI) of EFW. The issue had been cited as a Severity Level III design control violation with a civil penalty. However, the violation had subsequently been withdrawn by the NRC because the licensee's original design requirements did not include pump runout concerns. The violation withdrawal stated that further enforcement action was not warranted because the licensee planned to eliminate the NPSH problem by installing flow limiting venturis. However, the licensee had subsequently decided not to install the flow limiting venturis and had withdrawn the related commitment.

In response to the current inspectors' concerns with the reliance on operators performing complex actions within three minutes and the reliance on EFW pumps operating with inadequate NPSH for about two minutes, the licensee initiated a PIP, performed an operability evaluation, and discussed this issue with the NRC. The licensee stated that, as part of their operability evaluation, they discussed the issue with the EFW pump vendor and received a document from the vendor stating that the EFW pumps could operate for at least five minutes with insufficient NPSH without being damaged. The inspectors noted that the licensee had installed a main steam line break protection circuitry in about 1996 that automatically stopped main feedwater and also automatically stopped the turbine-driven EFW pump on a low OTSG pressure of 500 psig. This circuitry could potentially protect the turbine-driven pump from running with insufficient NPSH. However, the licensee did not want to rely on this circuitry, as part of their licensed EFW design basis, to protect the turbine-driven EFW pump from operating with insufficient NPSH. Instead, the licensee's operability evaluation concluded that the EFW system was operable based on a 1981 NRC SER that had approved the EFW system design with reliance on operator action, and the fact that the SER did not place time constraints on the operator action.

The NRC will continue to review the following potential design vulnerabilities: 1) the reliance on operator action to immediately throttle EFW flow while using non-safety related

equipment and while the EFW pumps operate with insufficient NPSH; 2) poor operator access to the handwheel of Unit 3 EFW flow control valve FDW-316; and 3) the licensee's plans for modifying the EFW system to eliminate the reliance on immediate operator action, using non-QA equipment, and pump operation in runout.

4&5) A caustic pump and a caustic valve. Each Oconee unit had one caustic pump and several handwheel-operated caustic valves, located in the auxiliary building, that must be manually operated during a loss of coolant accident. Operators would use this equipment to add sodium hydroxide to the containment sump for pH and iodine control. (At newer plants, this function was typically included in the automatic safety-related ECCS systems.) The caustic pump and valve were not QA (10 CFR 50, Appendix B did not apply), were not seismic, were not in a harsh environment (EQ was not applicable), were not in the IST program, and were not in the TS or another administrative control program. The pump was in a periodic testing program but the valve was not. (See Preventive Maintenance below.) The pump and valve were not in the PRA, since the lack of caustic addition would not have any impact on core damage probability and would have little effect on releases to atmosphere within the first 24 hours of an accident. (Note: The PRA only considers the first 24 hours of an accident.)

The inspectors found that the licensee had recognized the single failure vulnerability of the caustic addition system and engineers were informally investigating an alternate backup method for caustic addition. In response to inspectors' questions, the licensee opened a PIP to develop and write a procedure for an alternate method of caustic addition.

6) A main feedwater flow control valve. Each Oconee unit had two main feedwater flow control valves, one for each steam generator. These were air operated valves that received an automatic signal to close following a main steam line rupture. Each was designed to close fast enough to prevent overpressurizing the containment building. The valve bodies were QA-1 but the air operators were not QA and the air supply was not QA. On a loss of air pressure, the valves did not move - they failed 'as is.' The main feedwater flow control valve bodies were seismic but the air supply and operators were not; the valves were not in a harsh environment (EQ was not applicable), were in the IST program, and were in a PM program. The valves were not in TS but were in the SLC program which was an administrative control program similar to TS. The valves were not in the PRA because the core damage probability of the steam line rupture event was less than the PRA truncation level of 10 E-8.

The inspectors found that the NRC was currently reviewing the licensee's design for mitigating a main steam line break inside containment, including the design of the main feedwater flow control valves, pursuant to NRC Bulletin 80-04 and a related

license amendment request. The inspectors provided comments on this issue to the assigned NRC reviewers.

7&8) A main turbine stop valve and a main turbine stop valve trip solenoid valve. Each Oconee unit had four main turbine stop valves (two valves in parallel from each steam generator) located at the main turbine and two main turbine stop valve trip solenoid valves (in series) that tripped the four turbine stop valves. Each hydraulically operated main turbine stop valve must automatically close on a reactor trip to prevent RCS overcooling. (Note: There were no separate main steam stop valves.) The main turbine stop valve was QA-1 and seismic, as were the main steam lines from the steam generator to the main turbine stop valves. However, the trip solenoid valve was not QA and was not seismic. The stop valve and solenoid valve were not in a harsh environment (EQ was not applicable), were in the IST program, were in a PM program, and were in the TS. They were not in the PRA because their failure was bounded by a stuck open main steam relief valve. The turbine control valves also closed when the stop valve trip solenoid valves tripped and provided some backup for the turbine stop valves. Also, the turbine mechanical trip valve and immediate operator action to manually trip the turbine from the control room provided some backup for the stop valve trip solenoid valves. In response to a 1993 Unit 1 transient (documented in PIP 1-093-0950) caused by a stop valve trip solenoid valve failure (due to sticking), and also in response to 1993 requirements from their insurance company, the licensee had instituted a PM to periodically replace the turbine stop valve trip solenoid valves.

The inspectors found that the NRC had approved the licensee's turbine trip design, including the fact that the main turbine stop valve trip solenoid valves were not QA-1, in an NRC SER regarding GL 83-23, Required Actions Based on Generic Applications of the Salem Anticipated Transient Without Scram (ATWS) Event, dated August 3, 1995. The NRC had also addressed this issue in a letter dated October 6, 1995, which withdrew Deviation 50-269,270,287/95-09; Solenoid Valves Associated With Main Steam Stop Valves Are Not Safety-Related.

9&10) A control room ventilation system (CRVS) booster fan and a CRVS outside air damper. Each Oconee control room (one for Units 1 and 2 and one for Unit 3) had two outside air dampers and two 50% capacity booster fans. To provide 1/8-inch water gauge pressure in the control room for habitability during certain accidents, both outside air dampers and both booster fans must operate. The CRVS booster fan and damper were not QA, were not seismic, were not in a harsh environment (EQ was not applicable), were not in the IST program but were periodically tested by a performance test (PT), and were in the TS. The booster fan was in a PM program but the damper was not. The fan and damper were not in the PRA because their failure did not directly affect core damage probability or releases to the atmosphere. The inspectors

verified that the licensee's emergency operating procedures (EOPs) did not direct the operators to abandon the control room in the event of high radiation levels in the CRVS or in the control room. The licensee recognized that the CRVS was vulnerable to a single failure of a booster fan or a damper. In response to related NRC concerns documented in IR 50-269,270,287/98-03, the licensee was working to better seal the control rooms toward removing this single failure vulnerability. The licensee's sealing efforts included sealing leaks in ventilation ducts, repairing weak damper actuators, and repairing leaking dampers. The licensee contended that the NRC had not required that the CRVS be able to withstand a single failure when post-TMI action item III.D.3.4, Control Room Habitability, was applied to Oconee.

The licensee's position, that the CRVS was not required to be able to withstand a single failure, was currently under review by the NRC as part of URI 50-269,270,287/98-03-08.

11) A steam generator shell temperature computer point. Information from this computer point was relied on by operators to control the plant cooldown rate and ensure that it was not excessive. This temperature indication was not QA, was not seismic, was not in a harsh environment (EQ was not applicable), was not in the RG 1.97 program, was not in a PM program, was not in TS, and was not in the PRA. The inspectors found that the purpose of the operator use of this indication was to minimize temperature stresses in the OTSGs. Faster cooldown was not expected to immediately damage the OTSGs, but could increase the probability of future OTSG damage. Also, the operators had other indications to rely on for controlling the overall RCS cooldown rate. The inspectors concluded that, due to the low safety significance of a failure of this instrument, this item did not warrant further review.

Almost all (nine of eleven) of these examples of components that were vulnerable to single failure were not fully QA. None were major contributors to the PRA core damage probability, but two of the examples were significant contributors to the PRA probability of EFW system failure. Also, a main feedwater line break analysis that described a consequential loss of all EFW and all three trains of safety-related 4160 volt switchgear was apparently not addressed by the PRA. The inspectors plan to follow up on the following potential design vulnerabilities: 1) a single active failure in the open position of valve C-187 coincident with a main feedwater line break causing a loss of EFW; 2) a main feedwater line break in the turbine building causing consequential failures of the EFW system and all three trains of safety-related 4160 volt electrical switchgear; 3) the reliance on operator action to throttle EFW flow within three minutes while using non-safety related equipment and while the EFW pumps operate with insufficient NPSH; and 4) poor operator access to the handwheel of Unit 3 EFW flow control valve FDW-316.

Seismic

Thirteen of the 30 components were not seismically designed. Each of the components that was not seismically designed was not QA. Six of the thirteen were included in the SQUG Program. Under the SQUG Program, each non-seismic component needed to safely shut down the plant during normal (non-accident) conditions should be inspected by individuals experienced with seismic design. They should judge whether the installed components look like they would withstand an earthquake or whether modifications would be needed. The licensee would then install modifications as needed. The licensee's SQUG Program was included in the Oconee Recovery Plan.

Seven of the thirteen were not included in the SQUG Program: a hotwell level transmitter, caustic pump, caustic valve, steam generator shell temperature indication, control room ventilation radiation monitor, main feedwater block valve, and main steam stop valve trip solenoid valve. The inspectors verified that UFSAR Section 3.2.2 described the seismic design requirements and it did not require any of these components to be seismically designed. The main steam stop valve trip solenoid valve is discussed further under Single Failure above. The inspectors noted that the PRA identified a seismic event as the largest contributor to the potential for core damage.

Environmental Qualification

Five of the 30 components were in a potentially harsh environment. All five were QA-1 and were also EQ.

GL 89-10 MOV Program

Three of the 30 components were MOVs. One was QA-1 and was also in the GL 89-10 Program. Two were not QA and were not in the GL 89-10 Program. Those two, a main feedwater block valve and a main condenser vacuum breaker, were not vulnerable to single failure. While the main feedwater block valve was automatically closed on a main steam line rupture and provided some backup to the main feedwater flow control valve in mitigating a main steam line break, the licensee did not take credit for the valve closing in their accident analysis. Operators would have to open the main condenser vacuum breaker valve to use the water in the condenser hotwell as a backup source of water for the EFW pumps. However, the licensee did not take credit for the motor operator of the main condenser vacuum breaker but instead relied on handwheel operation of the valve. The inspectors verified that the licensee had satisfactorily tested the ability of operators to open the vacuum breaker valve to break condenser vacuum by using the handwheel.

RG 1.97 Program

Nine of the 30 components were instruments that provided indication on which operators would rely to perform emergency procedures. Six were in the RG 1.97 Program and also were QA-1. Three were not in the RG 1.97

Program and also were not QA. Those three were:

- Hotwell level indication, which would indicate to operators the availability of TS-required water in the condenser hotwell, for use as a backup source of water for the EFW pumps, as directed by EOPs. The licensee stated that the operators did not need to know the hotwell level as the EOPs contained no operator actions based on hotwell level.

- Steam generator shell temperature, which would be relied on by operators to control the plant cooldown rate. The licensee stated that operators could safely cool down the plant without reliance on steam generator shell temperature indication (see Single Failure above).

- Control room ventilation radiation monitor alarm, which had been relied on by operators as the signal to start the control room booster fans. Recently, the licensee revised emergency operating procedures to require operators to start the control room booster fans without relying on this alarm.

In-Service Testing

Eighteen of the 30 components were the type for which IST or other testing would be appropriate. Nine were in the IST Program, four were in the licensee's Appendix B Program (a periodic testing program similar to IST), and four were periodically tested under a Performance Test (PT) Program. One was not in any periodic testing program and also was not QA. The component, a caustic valve, is discussed above under Single Failure and is also discussed below under Preventive Maintenance. The licensee's OSRDC Program was designed to identify the lack of periodic testing for components like these and to add periodic testing.

Preventive Maintenance

Seven of the 30 components were not in a routine PM or calibration program. However, six of those seven components were in a periodic testing program - the one exception was a manual caustic valve that was not QA. The inspectors verified that EOPs required that the manual caustic valves be opened following a LOCA, to add sodium hydroxide to the containment sump during recirculation. The inspectors found that the licensee had an annual Caustic Injection System Pump Test (PT/1&2/A/0203/009, Revision 13, for Units 1 and 2 and PT /3/A/0203/009, Revision 11, for Unit 3) that tested the caustic pump and all but one of the caustic valves for each unit. The one valve per unit that was not tested was a manual caustic injection valve (1CA-62, 2CA-63, and 3CA-62).

The inspectors found that the licensee's maintenance rule program had addressed these caustic injection valves in closed PIP 0-090-3488, dated July 9, 1998. The PIP stated that an acceptable performance criteria for the chemical addition system function to "provide caustic addition

to sump" has not been identified. The PIP response, from the system engineer, stated that the annual performance test, PT/1&2/A/203/09 and PT/3/A/203/09, that recirculates the caustic to a bin, was the performance test for this function. The PIP response had overlooked the fact that the annual performance test did not test the manual caustic injection valves. A review of maintenance records found that valve 1CA-62 had last been stroked (the valve was replaced) in 1991; valve 2CA-63 had last been stroked (the valve was repacked) in 1994; and valve 3-CA-62 had last been stroked (a body to bonnet leak was repaired) in 1981. Since one of these valves had apparently not been operated in 17 years, the inspectors asked the licensee how they could assure that the valves were currently capable of fulfilling their intended function (being manually opened). In response, the licensee promptly revised the annual Caustic Injection System Pump Test procedures to include opening and reclosing the three manual caustic injection valves. Also, the licensee promptly opened and closed each valve and verified that they were capable of performing their intended function.

10 CFR 50.65 requires that the licensee monitor the performance of components, that are used in plant EOPs, in a manner sufficient to provide reasonable assurance that the components are capable of fulfilling their intended functions. Contrary to that requirement, the licensee had not monitored the performance of caustic injection valves 1CA-62, 2CA-63, and 3CA-62. Also, while 10 CFR 50, Appendix B, did not apply to these non-safety related valves, the licensee's corrective action for PIP 0-098-3488, dated July 9, 1998, had been poor in that it overlooked these caustic injection valves. After this issue was identified by the inspectors, the licensee took prompt corrective action. Also, the licensee's OSRDC Program had already included the caustic valves in a list of components relied on to mitigate accidents, and would have identified and corrected the lack of caustic valve testing within the next year. Further, the licensee stated that the OSRDC Program will coordinate any lack of testing and maintenance that it identifies with the Maintenance Rule Program. This non-repetitive, licensee-corrected violation that the licensee's established OSRDC Program would have soon identified is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This is identified as NCV 50-269,270,287/98-08-03: Failure to Monitor the Performance of Manual Caustic Injection Valves.

TS and SLC

Fourteen of the 30 components were in TS and five were in SLC. Eleven of the 30 components were not included in either the TS or SLC administrative control programs. Those eleven included: atmospheric dump valve, block valve for atmospheric dump valve, condenser vacuum breaker valve, motor-driven EFW pump UST suction isolation valve, turbine-driven EFW pump hotwell suction valve, caustic pump, caustic valve, UST level indication, condenser hotwell level transmitter, steam generator shell temperature indication, and control room ventilation radiation monitor. The inspectors found that six of these components were included in a licensee maintenance rule administrative control

program. The five components that were not in any administrative control program were: steam generator shell temperature indication, caustic pump, caustic valve, condenser vacuum breaker, and control room ventilation radiation monitor. Based on the low safety importance of these five components not being in an administrative control program, the inspectors did not pursue this issue any further.

Probabilistic Risk Assessment

Thirteen of the 30 components were not in the PRA. Eight are discussed above under Single Failure. The other five included:

- Letdown storage tank level indication. The licensee planned to include this in the next revision to the PRA as a result of the recent High Pressure Injection Study.

- Main steam pressure indication and main feedwater block valve. These components are involved in main steam line rupture event and are not in the PRA for the same reason as for the main feedwater flow control valve (see Single Failure above).

- Control room ventilation radiation monitor. This component was not in the PRA for the same reason as for the CRVS booster fan and damper (see Single Failure above).

- Manual valve for isolating the motor-driven EFW pump suction from the UST. Based on the inspectors questions, the licensee initiated a PIP to review why this valve was not included in the PRA.

c. Conclusions

The inspectors found that many components that were relied upon to mitigate design basis accidents were not in a QA program. Almost half (15 of 31) of the components reviewed were not fully QA. In addition, many of those same components (11 of 31) were vulnerable to single failure. URI 50-269,270,287/98-03-09 remains open pending further NRC review of the licensee's OSRDC program.

A non-cited violation of the maintenance rule was identified by the inspectors for a failure to monitor the performance of manual caustic injection valves. The licensee promptly responded to this issue, including cycling the caustic injection valves to assure that they were capable of fulfilling their intended function and revising a procedure to include cycling the valves annually.

The inspectors also identified a poor design condition for both timely access to equipment and personnel safety, in that operator access to the handwheel of Unit 3 EFW flow control valve FDW-316 involved walking on a horizontal pipe about 15 feet above the floor. This condition had existed for many years without licensee identification and corrective action.

Inspector Followup Item (IFI) 50-269,270,287/98-08-05, EFW Potential Design Basis Issues, will be identified for further NRC review of the following potential design vulnerabilities: 1) a single active failure in the open position of valve C-187 coincident with a main feedwater line break causing a loss of EFW; 2) a main feedwater line break in the turbine building causing consequential failures of the EFW system and all three trains of safety-related 4160 volt electrical switchgear; 3) the reliance on operator action to throttle EFW flow within three minutes while using non-safety related equipment and while the EFW pumps operate with insufficient NPSH; and 4) poor operator access to the handwheel of Unit 3 EFW flow control valve FDW-316.

E8.2 (Open) VIO 50-269,270,287/98-03-07: Incorrect and Nonconservative Assumptions in Control Room Operator Dose Calculations

a. Inspection Scope (92903,37550)

In response to this violation, the licensee committed to perform CRVS tracer gas testing to determine the amount of unfiltered inleakage into the control room while the booster fans were operating. The inspectors observed portions of this testing.

b. Observations and Findings

The inspectors observed the pre-evolution briefing and the tracer gas testing of the Unit 3 CRVS, conducted during evening off-hours. The inspectors observed that the sealing of leaks in the Unit 3 CRVS ventilation ducting, that was located outside the control room in the auxiliary building, looked very thorough and professional. Also, the sealing resulted in a substantial improvement in the attainable pressure in the Unit 3 control room, with two outside air booster fans running, from less that 0.125 inches water gauge (w.g.) early in 1998 to 0.4 inches w.g. during this inspection. The test prerequisites were appropriately met, tracer gas was injected, and some samples were taken; however, the observed test was voided because of problems with the laboratory equipment that was located in a nearby office building. The office building air conditioning had automatically turned off at night, causing the temperature-sensitive laboratory equipment to begin to overheat and potentially become less accurate. The test was rerun another night after reprogramming the air conditioner controls. The inspectors noted that preliminary test results, for tracer gas tests of both control rooms, were well within the licensee's test acceptance criteria. The inspectors plan to review the official test report after it is completed.

c. Conclusions

The inspectors observed that the sealing of leaks in the Unit 3 CRVS ventilation ducting, that was located outside the control room in the auxiliary building, looked very thorough and professional. Also, the sealing resulted in a substantial improvement in the attainable pressure in the Unit 3 control room, with two outside air booster fans running, from less that 0.125 inches w.g. early in 1998 to 0.4 inches w.g. during this inspection.

E8.3 (Open) VIO 50-269,270,287/98-03-02: Failure to Perform Penetration Room Ventilation System (PRVS) Surveillance in Accordance with TS

a. Inspection Scope (92903,37550)

In response to this violation, the licensee committed to perform PRVS Surveillance testing for air flow by using a pitot tube, as required by TS 4.5.4.1.b.1. The inspectors observed portions of this testing.

b. Observations and Findings

The inspectors observed the testing of the Unit 2 Train B PRVS system, per procedure TT/2/A/0110/202, Penetration Room Ventilation System 2B Pitot Tube Flow Test, Rev. 0, Change A, dated August 4, 1998. The inspectors verified that the procedure implemented the requirements of the TS and that licensee personnel followed the procedure using appropriate test instruments. The straight run of pipe in the flowpath upstream of the pitot tube testing location was 15 pipe diameters (15 feet of 12-inch pipe), which exceeded the seven pipe diameters usually needed for good flow measurement accuracy. The pitot tube was held by hand during the flow measurements by a licensee contractor who was experienced in performing such flow measurements. At the inspector's request, the licensee verified and the inspectors observed that angular movement of the pitot tube by as much as about 20 degrees did not affect the flow measurement.

The initial test result indicated a flowrate of 1156 cfm, which exceeded the TS allowable flowrate of 1000 cfm +/- 10 percent. The licensee appropriately adjusted the flowrate and ran the test again, with an acceptable result of 989 cfm, and then properly re-blocked the position of the 2B PRVS flow control valve. The licensee then tested the Unit 2 penetration room pressure, with the 2B PRVS fan running, and verified that the penetration room pressure was still negative with respect to all adjacent rooms (as required for PRVS operability). That satisfactorily completed the 2B PRVS testing. The licensee appropriately kept the Unit 2 PRVS in the required TS action statement throughout the testing. Licensee test procedures, oversight, and performance were good.

c. Conclusions

The inspectors concluded that the licensee's procedures, oversight, and performance of the surveillance testing of the Unit 2B PRVS air flow, using a pitot tube, were good.

E8.4 (Closed) IFI 50-269,270/97-01-01: Reactor Trip Confirm Circuit Fuse Inspection

On or about March 3, 1997, the licensee identified that fuses installed in the redundant trip confirm circuity were of the wrong size. For example, the vendor's drawing for Unit 3 showed several fuses as 0.5 amp and others as 5.0 amps. In addition some fuses were shown as 0.25 amp

and 10 amp. Units 1 and 2 exhibited similar discrepancies.

The correct fuses were determined and installed in all three units. The instrument and electrical (I&E) procedure for breaker testing, (IP/01A/0305/014-1: RPS Control Rod Drive Breaker Trip and Events Recorded Timing Test) that led to the discovery of improper size fuses, was revised to include a visual inspection for blown fuses prior to beginning breaker testing. This was apparently the cause of the Unit 3 reactor trip on March 3, 1997. It was determined that a reactor trip may occur if a blown fuse existed in the circuit when performing IP/01A/0305/014-1.

The licensee issued PIP 0-097-1014 on March 3, 1997, to resolve the fuse size discrepancies found while troubleshooting the root causes of the Unit 3 reactor trip.

The licensee's review of the history and causal factors with an issue involving fuses in the reactor trip confirm circuit was thorough and timely. The vendor drawings have been revised and the correct fuses have been installed. This IFI is closed.

E8.5 (Closed) URI 50-269/98-02-09: Failure of Valve 1HP-27 to Close

(Closed) LER 50-269/98-05-01: Valve Fails to Close Requiring Unit Shutdown Due to Inadequate Procedure

(Closed) LER 50-269/98-05-00: Valve Fails to Close Requiring Unit Shutdown

This URI and LER involved the failure of Valve 1HP-27 to close during engineered safeguards (ES) testing on February 14, 1998. At that time the licensee determined that the design basis should have assumed the worst case static pressure acting under the seat instead of worst case differential pressure across the valve. This item has remained unresolved pending NRC review of the past operability evaluation.

The licensee determined that even though Valve 1HP-27 would not throttle closed under some conditions, the HPI system would have performed its safety functions. In addition, the licensee reworked and tested valve 1HP-27 and revised the design basis calculations for all HPI injection and crossover valves to include the higher static pressure. The licensee also planned to replace the motor operators for all HPI injection and crossover valves with larger ones. This has already been completed on Unit 2 and has been scheduled for Units 1 and 3 during upcoming outages.

The inspectors reviewed the past operability evaluation and determined it was acceptable. However, the use of differential pressure instead of static pressure acting under the seat in the design basis constituted a violation of 10 CFR 50 Appendix B, Criterion III. This non-repetitive, licensee-identified and corrected violation is being treated as a NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. This is

identified as NCV 50-287/98-08-04: Improper Design Basis Assumptions for HPI Valves. These items are closed.

A non-cited violation was identified for improper design basis assumptions regarding the high pressure injection system injection and crossover valves.

The identification, analysis, and resolution of the design basis concerns related to the failure of Valve 1HP-27 to close were adequate.

E8.6 Seismic Qualification Utility Group (SQUG) Program Implementation

a. Inspection Scope (92903)

The inspectors reviewed the SQUG program implementation, outlier resolutions, and modifications to determine the adequacy of the SQUG program.

b. Observations and Findings

The inspectors discussed the SQUG program and its implementation with engineering personnel. The licensee had completed the selection and walkdowns of the safe shutdown equipment. The forms used for the walkdown screening or evaluation were called "Screening Evaluation Work Sheets (SEWS)" which were provided by the General Implementation Procedure (GIP) for more than 20 types of equipment or devices. If equipment or devices were outside those lists, they would be identified as outliers. The licensee completed 1692 walkdowns and generated 466 outliers for equipment. The licensee also evaluated 6135 devices for chatter contact and generated 730 outliers.

The licensee resolved about 630 outliers. The remaining outliers will be repaired, replaced, modified, or require further analyses. The licensee recently completed modifications in the Keowee hydro station.

The inspectors randomly selected a portion of the Emergency Feed Water (EFW) line for walkdowns to verify that the equipment or devices for the safe shutdown along this line had been walked down and documented by the licensee. The portion of the line selected was from Upper Surge Tank 3A at the turbine building deck to valve 3CVA0391 in the turbine building basement, approximately 120 feet. The equipment included one upper surge tank, three air operated valves, one motor-driven emergency feed water pump, one isolation valve, one motor-operated valve, two pressure switches, four oil pressure switches, two level transmitters, two water level indicators, and associated relays, cabinets, and other control switches. The inspectors reviewed the SEWS and other information provide by the engineers for equipment and the devices identified along the line and found that they were adequately documented and evaluated. The upper surge tank required outliers for the evaluation of the saddle spacing, anchorage type, and the support legs. Modifications were required to resolve the outliers.

The inspectors randomly selected five repairs or modifications completed in the Keowee hydro station to determine if the resolution of the outliers was adequate. The following five repairs or modifications stated in PIP 0-096-2783 were walked down by the inspectors and are listed below:

Component	Description of Work
SYDC-1 and 2	Increased weld size for anchorage
SYTC cabinets	Added padding between cabinets and columns for interaction
Battery Racks	Replaced multiple compressible styrofoam with rigid plexiglass at each end of the racks
HVAC AHU003	Added a horizontal restraint to prevent it from hitting the cabinets
Cabinet 1LC1	Added padding between cableway and 1LC1 to reduce the seismic impact on essential relays

The inspectors measured the weld size, length, anchor bolt diameters, end attachments, steel wire, and examined the padding and plexiglass. All the repairs or modifications met the drawing requirements.

The inspectors reviewed the SEWS and associated outliers related to the equipment and devices in the EFW line walkdown. The outliers were stated in the comments of the SEWS and the reasons for the further evaluations or reviews were stated. The inspectors also reviewed five resolved outliers for the High Pressure Injection (HPI) and Emergency Feed Water (EFW) Systems. They involved remote starter enclosures 3RSC-3HP-409 and -410 for HPI; nitrogen supply bottles for feedwater valves 315 and 316; main steam valves 87, 126, and 129; and EFW pump turbine oil tanks 1TOTK0002 and 3TOTK0002. The licensee adequately resolved the outliers reviewed.

c. Conclusions

Based on the sample reviewed, the licensee exhibited good progress in the evaluation and resolution of the outliers for the SQUG program. Most outliers resolved to date have been through analyses or documentation review. More complex outliers remain to be resolved by repairs, modifications, or refined analyses.

This Recovery Plan Item is closed.

E8.7 Walkdown of Nitrogen Supply System for EFW Line

a. Inspection Scope (92903)

The inspectors walked down the nitrogen supply system to determine if the system met seismic qualified requirements.

b. Observations and Findings

This nitrogen supply system was required to be seismically qualified per the NRC letter from John F. Stolz, Director, PWR Project Directorate Number 6, to Hal B. Tucker, Vice President - Nuclear Operations, dated January 14, 1987, subject, "Seismic Qualification of the Emergency Feedwater System." This letter stated that the licensee has committed to assure that the automatic bottled nitrogen system, including power to the solenoid valves, will withstand an MHE. The MHE is defined as Maximum Hypothetical Earthquake or Safe Shutdown Earthquake (SSE).

The inspectors walked down non-safety-related nitrogen lines from the nitrogen supply bottles to valves FDW 315 and 316 for all three units with the licensee's engineers and instrument operators. These lines are required for safe shutdown. The inspectors identified minor discrepancies which were provided to the licensee for resolution.

The licensee issued PIP 0-098-4187, Revisions 0 and 1 to record the deficiencies found by the inspectors and to evaluate the root cause and their resolution. The PIP stated that the deficiencies found in the nitrogen supply systems degraded the systems and did not meet the standards for seismic mounting. The nitrogen supply lines were not safety-related and remained operable. The inspectors agreed with the licensee's operability evaluation for the systems.

In 1996 the SQUG program personnel did perform the walkdowns for valves FDW 315 and 316 and nitrogen bottles and no equipment deficiencies were identified. These walkdowns did not include the nitrogen supply lines where the inspectors identified the deficiencies.

c. Conclusions

The deficiencies found in the seismic mounting of the nitrogen supply lines for all three units degraded the EFW systems and indicated a weakness in maintaining the nitrogen supply line supports.

IV. Plant Support Areas

R1 Radiological Protection and Chemistry Controls

R1.1 Tour of Radiological Protected Areas

a. Inspection Scope (86750)

The inspectors reviewed implementation of selected elements of the

licensee's radiation protection program as required by 10 CFR Parts 20.1902, and 1904. The review included observation of radiological protection activities for control of radioactive material, including postings and labeling, and radioactive waste processing.

b. Observations and Findings

The inspectors reviewed survey data of radioactive material storage areas. Observations and independent radiation and contamination survey results determined the licensee was effectively controlling and storing radioactive material and all material observed was appropriately labeled as required by 10 CFR Part 20.1904. All areas observed were appropriately posted to specify the radiological conditions.

The inspectors determined the licensee was processing radioactive waste to maintain exposures As Low As Reasonably Achievable (ALARA) and to minimize quantities of radioactive waste stored on site. During the inspection, the inspectors observed a liquid radioactive waste discharge of 28,000 gallons and determined licensee personnel were following the discharge procedure CP/0/B/5200/48, "Resin Recovery System Operation", Revision 58. The inspectors also determined licensee personnel involved with the discharge were knowledgeable about release criteria, alarm limits, and discharge pathways. The licensee was trending liquid radioactive waste to meet licensee established goals. As of August 26, 1998, the licensee had released approximately 0.236 curies which was below the year to date goal of 0.380 curies. Work practices observed during radioactive waste processing were good.

c. Conclusions

The inspectors determined the licensee was effectively maintaining controls for radioactive material storage and radioactive waste processing. Work practices observed during radioactive waste processing were good.

R1.2 Water Chemistry Controls

a. Inspection Scope (84750)

The inspectors reviewed implementation of selected elements of the licensee's water chemistry control program for monitoring primary and secondary water quality as described in the TS limits, the Station Chemistry Manual, and the UFSAR. The review included examination of program guidance and implementing procedures and analytical results for selected chemistry parameters, and observation of chemistry technicians collecting water samples.

b. Observations and Findings

The inspectors toured the primary and secondary chemistry laboratories and observed work in progress. The inspectors observed a survey of the primary laboratory and observed personnel frisking with laboratory coats

worn. Personnel observed were using good radiological work practices.

The inspectors reviewed selected analytical results recorded for Unit 1 reactor coolant taken between the period April 15, 1998, and August 26, 1998, and secondary samples taken between the periods May 25, 1998, and August 3, 1998. The selected parameters reviewed for primary chemistry included dissolved oxygen, chloride, pH, and fluoride. The selected parameters reviewed for secondary chemistry included hydrazine, iron, copper, sodium, dissolved oxygen, and chloride. Those primary parameters reviewed were maintained within the relevant TS limits for power operations. Those secondary parameters reviewed were maintained within the limits of the Station Chemistry Manual.

The inspectors observed a boron sample collection from Unit 1 primary system during startup. The inspectors verified that the sample collection was performed as required by licensee chemistry sampling procedure CP/1/A/2002/001, "Unit 1 Primary Sampling System", Revision 34. The sample was analyzed as required by licensee procedure LM-O-P003A, "Determination of Boron Using the Mettler DL40GP", Revision 4. Chemistry personnel performing the sampling and analysis followed the procedures and appeared well trained to perform the task.

The inspectors observed a test of the Unit 2 post-accident liquid sampling system (PALS). The individuals observed followed the established procedure CP/2/A/2002/004D, " Test Procedure for the Post Accident Liquid Sampling System", Revision 23. However, the PALS test was secured due to system leakage. The system was removed from service for maintenance.

c. Conclusions

The inspectors concluded that the licensee's water chemistry control program for monitoring primary and secondary water quality had been effectively implemented in accordance with the TS requirements and the Station Chemistry Manual for water chemistry. The inspectors also concluded that the collection of the samples was performed in accordance with the licensee's chemistry sampling procedure.

R2 Status of RP&C Facilities and Equipment

R2.1 Process and Effluent Radiation Monitors

a. Inspection Scope (84750)

The inspectors reviewed selected licensee procedures and records for required surveillance on process and effluent radiation monitors and for radiation monitor availability as required by TS, and Chapter 16 of the UFSAR.

Observations and Findings

During tours of the auxiliary building, turbine building, and radwaste building, the inspectors observed the physical operation of process radiation effluent monitors in service. The inspectors also toured the control rooms and observed the status of radiation monitoring equipment. The inspectors reviewed radiation and process monitor surveillance procedures and records for performance of channel checks, source checks, channel calibrations, and channel operational tests for four monitors. The inspectors also observed control room personnel perform alarm set points for four monitors as required by licensee procedure PT/0/A/0230/001, "Radiation Monitor Check", Revision 112. The inspectors determined the licensee was performing checks described in the TSs and Chapter 16 of the UFSAR and in accordance with license procedures.

The inspectors reviewed the licensee's 1997 Annual Environmental Report issued in May 1998. No equipment or sampling deviations for liquid samplers, environmental air samplers, or environmental thermoluminescent dosimetry (TLD) were identified during 1997. The licensee had moved one control location air sampler due to the construction of a school.

The inspectors also performed independent environmental surface contamination surveys of selected areas near the licensee's visitors center and confirmed survey results to be background as consistent with licensee survey results reviewed.

c. Conclusions

The inspectors concluded radiation and process effluent and environmental monitors were being maintained in an operational condition to comply with TS requirements and UFSAR commitments.

R2.2 Meteorological Monitoring Equipment

a. Inspection Scope (84750)

The inspectors reviewed licensee procedures to verify licensee compliance with the UFSAR which described the operational and surveillance requirements for the meteorological monitoring instrumentation.

b. Observations and Findings

The inspectors toured the control room and determined the meteorological instrumentation was operable and that data for wind speed, wind direction, air temperature, and precipitation were being collected as described in the UFSAR. Based on review of records, the licensee was tracking operability for meteorology equipment during 1998. Based on licensee operation records reviewed for wind speed, wind direction, and precipitation, the inspectors determined the licensee was adequately maintaining meteorological monitoring equipment and that the

meteorological monitoring program had been adequately implemented.

c. Conclusions

Based on the above reviews and observations, it was concluded that the meteorological instrumentation had been adequately maintained and that the meteorological monitoring program had been adequately implemented.

P2 Status of EP Facilities, Equipment and Resources

P2.1 Resident Inspector Tour of the Public Document Room (PDR) (71750)

The inspectors toured the PDR located at the Oconee County Public Library, 501 W. South Broad Street, Walhalla, S.C., 29691. Required equipment and files were in good working order. The inspectors verified the condition of the equipment and files (on microfiche) by viewing and printing pages from inspection reports and correspondence.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management on August 20 and September 4, 1998, and at the conclusion of the inspection on September 10, 1998. The licensee acknowledged the findings presented. No proprietary information was identified to the inspectors.

Partial List of Persons Contacted

Licensee

L. Azzerello, Mechanical Systems/Equipment Engineering Manager
E. Burchfield, Regulatory Compliance Manager
T. Coutu, Nuclear Support Section Manager
T. Curtis, Superintendent of Operations
G. Davenport, Operations Support Manager
B. Dobson, Engineering Work Control Manager
J. Forbes, Station Manager
W. Foster, Safety Assurance Manager
T. Hartis, Strategic Business Consultant
D. Hubbard, Engineering Modifications Manager
C. Little, Electrical System/Equipment 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, Radiation Protection Manager

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

NRC

D. LaBarge, Project Manager

Inspection Procedures Used

IP37550	Engineering
IP37551	Onsite Engineering
IP40500	Effectiveness of Licensee Controls In Identifying and Preventing Problems
IP61726	Surveillance Observations
IP62707	Maintenance Observations
IP71707	Plant Operations
IP71750	Plant Support Activities
IP73753	Inservice Inspection
IP84750	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP86750	Solid radioactive Waste Management and Transportation of Radioactive Materials
IP90712	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP92700	Onsite Followup of Written Event Reports
IP92901	Followup - Plant Operations
IP92902	Followup - Maintenance
IP92903	Followup - Engineering

Items Opened, Closed, and Discussed

Opened

50-269,270,287/98-08-01	URI	Configuration Control of the Station ASW Pump (Section M1.2)
50-269,270,287/98-08-02	VIO	Inadequate 50.59 Safety Evaluation for 1996 UFSAR Revision Related to ECCS Pumps' NPSH Analysis (Section E1.4)
50-269,270,287/98-08-03	NCV	Failure to Monitor the Performance of Manual Caustic Injection Valves (Section E8.1)
50-269,270,287/98-08-04	NCV	Improper Design Basis Assumptions for HPI Valves (Section E8.5)
50-269,270,287/98-08-05	IFI	EFW Potential Design Basis Issues (Section E8.1)

Closed

50-269,270,287/95-03-01	IFI	Clarification of TS 3.3.1 (Section O8.1)

50-269/90-15	LER	Unit Operation In an Unanalyzed Condition Due to Design Deficiency, Design Oversight (Section O8.1)
50-269,270,287/97-05-02	VIO	Failure to Maintain Configuration Control (Section O8.2)
50-269,287/97-15-01	VIO	Failure to Complete Required TS Surveillance on LPI Flow Instruments (Section O8.3)
50-269/97-09-00	LER	LPI Flow Instrument TS Surveillance Interval Exceeded Due to Deficient Work Practices (Section O8.3)
EA 96-478-01014	VIO	Failure to Properly Install MSSV Spindle Nut Cotter Pins (Section O8.4)
50-269/97-08-00	LER	Manual Reactor Trip Due to Equipment Failure While Shutdown (Section O8.5)
50-270/97-02-00	LER	Grid Disturbance Results in Reactor Trip Due to Manufacturing Deficiency (Section O8.6)
EA 97-298-04014	VIO	Failure to Follow Operations Procedures Relating to Low Temperature Overpressure Protection Requirements (Section O8.7)
EA 97-298-03014	VIO	Failure to Follow Operations Procedure During the Unit 3 Cooldown on May 3, 1997 (Section O8.7)
EA 97-298-05014	VIO	Failure to Follow Maintenance Procedures for the Installation of Tubing (Section O8.7)
50-287/97-03-00	LER	HPI System Inoperable Due to Design Deficiency and Improper Work Practices (Section O8.7)
50-269/97-11-00	LER	Steam Generator Leak Results in TS Unit Shutdown Due to Inadequate Process Control (Section M8.1)
50-270/98-01-00	LER	Operation with Steam Generator Tube Indications in Excess of Limits Due to Manufacturing Error (Section M8.2)

50-287/97-02-00	LER	Reactor Building Cooling Units Technically Inoperable (Section M8.3)
50-287/97-02-01	LER	Reactor Building Cooling Units Technically Inoperable Due to a Manufacturing Deficiency (Section M8.3)
50-269,270/97-01-01	IFI	Reactor Trip Confirm Circuit Fuse (Section E8.4)
50-269/98-02-09	URI	Failure of Valve 1HP-27 to Close (Section E8.5)
50-269/98-05-01	LER	Valve Fails to Close Requiring Unit Shutdown Due to Inadequate Procedure (Section E8.5)
50-269/98-05-00	LER	Valve Fails to Close Requiring Unit Shutdown (Section E8.5)

Discussed

50-269,270,287/98-03-09	URI	Licensing Basis Issues With Single Failure and QA for Non-Safety Equipment Required to Mitigate an Accident (Section E8.1)
50-269,270,287/98-03-07	VIO	Incorrect and Nonconservative Assumptions in Control Room Operator Dose Calculations (Section E8.2)
50-269,270,287/98-03-02	VIO	Failure to Perform PRVS Surveillance in Accordance With TS (Section E8.3)
50-269/98-01	LER	Available NPSH for RBS Pumps Outside Design Basis Due to Incorrect Interpretation (Section E1.4)
50-269/97-02	LER	Reactor Building Cooling Units Technically Inoperable Due to Design Deficiency (Section O1.4)
50-269/97-02-01	LER	Reactor Building Cooling Units Technically Inoperable Due to Design Deficiency (Section O1.5)
50-270/98-06-00	LER	ESV (2 Trains) Inoperable (Section O1.5)

List of Acronyms

AFC	Auxiliary Fan Coolers
ALARA	As Low As Reasonably Achievable
ASME	American Society of Mechanical Engineers
ASW	Auxiliary Service Water
ATWS	Anticipated Transient Without Scram
BWST	Borated Water Storage Tank
CFM	Cubic Feet Per Minute
CFR	Code of Federal Regulations
CRVS	Control Room Ventilation System
DEA	Decontamination Emergency Area
DSCS	Double Seal Delta Channel Seal
ECCS	Emergency Core Cooling Systems
EFW	Emergency Feedwater
EOC	End-of-Cycle
EOP	Emergency Operating Procedure
EQ	Environmental Qualification
ES	Engineered Safeguards
ESF	Engineered Safety Feature
ESV	Essential Siphon Vacuum
F	Fahrenheit
FIP	Failure Identification Process
GL	Generic Letter
GPM	Gallons Per Minute
HPI	High Pressure Injection
I&E	Instrument & Electrical
IFI	Inspector Followup Item
INOT	Independent Nuclear Oversight Team
IP	Inspection Procedure
IR	Inspection Report
ISI	Inservice Inspection
IST	In-Service Testing
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
LSE	Less Significant Event
MOV	Motor Operated Valve
MSE	More Significant Event
MSSV	Main Steam Safety Valve
NCV	Non-Cited Violation
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NSD	Nuclear System Directive
NSM	Nuclear Station Modification
OTSG	Once Through Steam Generator

OSRDC	Oconee Safety-Related Designation Clarification Program
PALS	Post Accident Liquid Sampling System
PDR	Public Document Room
PIP	Problem Investigation Process
PM	Preventive Maintenance
ppb	Parts per Billion
PRA	Probablistic Risk Assessment
PRVS	Penetration Room Ventilation System
psig	Pounds Per Square Inch Gauge
PT	Performance Test
QA	Quality Assurance
RB	Reactor Building
RBCU	Reactor Building Cooling Unit
RBS	Reactor Building Spray
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
SALP	Systematic Assessment of Licensee Performance
SD	Shutdown
SLC	Selected Licensee Commitments
SRG	Safety Review Group
SQUG	Seismic Qualification Utility Group
SSCs	Systems, Structures, and Components
SSEA	Safety System Engineering Audit
SSF	Standby Shutdown Facility
SSFI	Safety System Functional Inspection
TAC	Technical Assignment Control
TLD	Thermoluminescent Dosimetry
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
USQ	Unreviewed Safety Question
UST	Upper Storage Tank
UT	Ultrasonic Examination
VIO	Violation
w.g.	Water Gauge
WO	Work Order