U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Wisconsin Electric Power Company
Facility:	Point Beach Nuclear Plant, Units 1 & 2
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EXECUTIVE SUMMARY

Point Beach Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-266/99002(DRP); 50-301/99002(DRP)

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 7-week inspection period by the resident inspectors.

Operations

- The licensee promptly and thoroughly evaluated an industry operating experience bulletin on a certain type of electrical circuit breaker. The licensee demonstrated an appropriately conservative operating philosophy in declaring inoperable several of these breakers and shutting down the operating unit after a similar breaker in a nonsafety-related application was found to be physically degraded. While the licensee's initial operability determination for this issue failed to identify all the potential system impacts, the questioning attitude of an on-shift operating crew led to the conservative decision to shut down the Unit until the problem was resolved. (Section O1.1)

- Better maintenance practices and more timely completion of a breaker replacement project could have eliminated the need to shut down the operating unit. (Section O1.1)

- During the Unit 1 startup, the duty shift superintendent (the lead senior reactor operator) performed a thorough pre-job brief and provided effective overview of control room activities. Reactor engineering personnel provided an acceptable estimated critical rod position calculation for the Unit 1 startup. (Section O1.2)

- The inspectors identified that the licensee lacked alarm response instructions for operationally significant alarms generated by the plant process computer system and did not have procedural controls for disabling control room alarms. (Section O1.2)

- The inspectors performed an inspection of the Unit 2 containment to assess cleanliness and safety-related system and component readiness for unit restart. Other than minor items which the licensee addressed, systems, components, and general housekeeping were appropriate for unit startup. (Section O2.1)

- The inspectors identified four areas of concern with the licensee's use and implementation of abnormal operating procedures and emergency operating procedures: the procedure deviation process, immediate operator actions, reference procedure use, and AOP exit requirements. Two examples of a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," were identified. (Section O3.1)

- The licensee did not routinely evaluate the impact of inoperable, degraded, or nonconforming equipment unless the equipment was required by Technical Specifications. While acceptable within the regulations, this practice made the licensee vulnerable when the failure of non-Technical Specification-required equipment had an impact on the operability of equipment with more safety significance, as in the facade freeze protection case described in Inspection Report 50-266/99004(DRP). (Section O3.2)

Maintenance

- Two major refueling outage surveillance tests were conducted well. All safety-related equipment functional requirements were satisfied. Operators displayed good questioning attitude in response to the questionable performance of several valves during a third surveillance test, and the operations test director suspended the testing activity. (Section M1.1)

- Operators failed to promptly enter applicable abnormal operating procedures following an unanticipated loss of power to safety-related buses. Restoration of power to the buses took considerably longer than during a similar event in 1997 because of a less focused operator response (Section M1.1)

- The licensee completed many important to safety modifications during the Unit 2 refueling outage. Examples included reactor vessel baffle bolt replacement, main control board wire separation, and over-pressure protection for containment penetrations and motor operated valves. (Section M2.1)

- There were several examples of safety-related equipment that failed post-maintenance testing and periodic surveillance tests and an instance where foreign material (pieces of a cloth rag) was left in the reactor coolant system after maintenance activities and caused a minor water hammer in the chemical and volume control system. The maintenance-related problems were more significant than those observed during previous outages. (Section M2.2)

Engineering

- The licensee was slow to recognize generic weaknesses in the programs for controlling the use of lubricants in safety-related applications. Examples of the problems included inconsistencies among various licensee documents, and poor follow-through by engineering staff or poor communications between engineering groups when addressing lubrication issues. (Section E1.1)

- The inspectors determined that the licensee's evaluation of cross-tying safety-related 480 volt buses was thorough and well documented. Equipment configuration restrictions specified in the evaluation were verified by the inspectors to have been properly implemented. (Section E2.1)

Plant Support

- Throughout the inspection period, the inspectors observed radiological control postings and radiation protection technician performance during tours of the radiologically controlled area, including Unit 2 containment. Postings and surveys for radiological areas were appropriate and current. Technicians provided appropriate radiological oversight of work activities. (Section R1)

Report Details

Summary of Plant Status

The inspection period started with Unit 1 at full power. On January 5, 1999, Unit 1 power was reduced to approximately 23 per cent as part of a Technical Specification (T/S)-required shutdown associated with the apparent inoperability of both safety injection pumps, as described in Inspection Report (IR) 50-266/99004(DRP). The power reduction was terminated when the NRC issued a notice of enforcement discretion. Full power operations were resumed a day later. Unit 1 was shut down on January 22, when the licensee identified a potential problem with 4160-volt electrical circuit breakers. The unit was restarted on January 24 and remained at full power through the end of the period. Unit 2 remained in a refueling outage throughout the period.

I. Operations

O1 Conduct of Operations

O1.1 Identification of Potential Problems with Safety-Related Electrical Breakers

a. Inspection Scope (Inspection Procedure (IP) 71707)

The inspectors reviewed the licensee's actions taken in response to an industry operating experience bulletin describing problems with Westinghouse type "DH" electrical breakers.

b. Observations and Findings

Another nuclear utility experienced a problem with a nonsafety-related Westinghouse type "DH" electrical breaker on January 13, 1999. The problem involved a block of non-conductive shielding on the breaker arc chute which had come loose and jammed the breaker operating mechanism. An operational experience report was distributed on January 19, and on January 21, the Point Beach operating experience staff identified that this style breaker was used in safety-related applications at Point Beach. This fact was entered into the licensee's corrective action program to ensure that it was promptly evaluated.

In response to the identified concern, the licensee established an inspection plan to determine whether the shielding blocks in Point Beach's DH-style breakers were adequately restrained. The breaker inspections identified that shielding blocks in several safety-related breakers were loose, and a shielding block in a nonsafety-related breaker was found to have fallen onto the operating mechanism. An operability determination (OD) completed on January 22 appropriately concluded that the block in the safety-related breakers might eventually fall onto or into the operating mechanism. While the initial OD failed to identify all the potential system impacts, the questioning attitude of an on-shift operations crew led to the determination that a reactor protection system function should be declared inoperable because of the potential for a malfunction of a safety-related breaker. This resulted in the operating unit (Unit 1) being shut down on January 22.

The licensee modified all the safety-related DH-style breakers, and Unit 1 was restarted on January 24. The modification provided reasonable assurance that the shielding block would not fall into the operating mechanism.

While the licensee response to the industry operating experience bulletin was prompt, thorough, and appropriate, better maintenance practices could have resulted in earlier identification and correction of the degraded (loose) shield blocks. The licensee was in the process of performing a long-term replacement of the DH-style breakers with newer vacuum breakers; however, the replacement initiative had not been completed prior to the identification of this problem.

c. Conclusions

The licensee promptly and thoroughly evaluated an industry operating experience bulletin on a certain type of electrical circuit breaker. The licensee demonstrated an appropriately conservative operating philosophy in declaring inoperable several of these breakers and shutting down the operating unit after a similar breaker in a nonsafety-related application was found to be physically degraded. While the licensee's initial operability determination for this issue failed to identify all the potential system impacts, the questioning attitude of an on-shift operating crew led to the conservative decision to shut down the Unit until the problem was resolved.

O1.2 Unit 1 Startup

a. Inspection Scope (IP 71707)

The inspectors observed portions of the Unit 1 startup on January 24, 1999. In addition the inspectors reviewed the following documents:

- Operating Procedure (OP) 1B, "Reactor Startup," Revision 33
- OP 1B, Appendix A, "Estimated Critical Position Calculation," Revision 7
- Abnormal Operating Procedure (AOP) 6B, "Stuck Rod or Malfunctioning Position Indication Unit 1," Revision 10
- Reactor Engineering Instruction 44.0, "Shutdown Margin for an Operating Reactor."

b. Observations and Findings

The inspectors observed the duty shift superintendent (DSS) perform a pre-job briefing with the operators and reactor engineers prior to reactor startup. The briefing thoroughly covered command and control, roles, responsibilities, recent equipment issues, and reactivity management. During the Unit 1 startup, the DSS effectively maintained oversight of the control room. The DSS appropriately did not become intimately involved in the evolution and provided direction and guidance as needed.

The inspectors verified the reactor engineers properly calculated an estimated critical rod position. The reactor achieved criticality within 25 steps of the estimated rod position. This was within the calculated acceptance band.

During the Unit 1 startup, control rod misalignment alarms from the plant process computer system (PPCS) were frequently received. Response to these alarms resulted in multiple entries into T/S action statements, and in one instance also required entry into AOP 6B. The inspectors verified that operators complied with the T/S action requirements and correctly implemented the applicable portions of AOP 6B. The inspectors identified a general concern regarding AOP usage which is discussed in detail in Section O3.1 of this report.

The inspectors determined that the licensee did not have any alarm response instructions for PPCS-generated, operationally significant alarms, such as "Rod Misalignment." The inspectors identified that while many PPCS generated alarms also had corresponding control board annunciators, some did not. The inspectors were concerned that operators did not have sufficient guidance to respond to operationally significant PPCS alarms that did not have a corresponding control room alarm. The inspectors discussed the concern with plant management, who indicated that alarm response instructions for operationally significant PPCS alarms would be included as part of the PPCS upgrade project.

Also during the startup, the inspectors observed the DSS instruct the operators to disable the "Rod Bottom Rod Drop" control board alarm. The DSS stated that the alarm had not been working properly, and that repairs had been requested. In response to inspector questions, the DSS stated that the alarm had been disabled in accordance with Operations Manual (OM) Procedure 3.12, "Control of Equipment and Equipment Status," Revision 4. The inspectors found that OM 3.12 did not specifically address disabling control board alarms. The issue that no documented controls existed for disabling control room alarms had been discussed in prior IRs (see IR 50-266/98003(DRP); 50-301/98003(DRP), Section E2.1). At that time, the licensee issued informal guidance, until a procedure could be developed, regarding how to disable control board alarms until a procedure could be developed. The inspectors identified that the formal procedure had not yet been finalized, and discussed with station management the concern that operators had not consistently implemented the informal guidance. Station management agreed that the formal procedure was needed.

c. <u>Conclusions</u>

During the Unit 1 startup, the DSS performed a thorough pre-job brief and provided effective overview of control room activities. Reactor engineering personnel provided an acceptable estimated critical rod position calculation for the Unit 1 startup. The inspectors identified the licensee lacked alarm response instructions for operationally significant PPCS-generated alarms and did not have procedural controls for disabling control room alarms.

O1.3 Observation of Loading of the Fifth Dry Storage Spent Fuel Cask

a. Inspection Scope (IP 60855)

From November 9 through November 13, 1998, the inspectors observed various portions of the loading of the fifth dry storage spent fuel cask to verify compliance with the applicable sections of the dry cask loading procedures.

b. Observations and Findings

The inspectors observed that the licensee effectively implemented lessons learned from previous dry cask loadings. The inspectors did not observe any of the same problems seen during previous loads. Engineering, operations, and radiation protection personnel provided very good control of the evolution.

c. Conclusions

The loading of the fifth dry storage spent fuel cask was performed well.

O2 Operational Status of Facilities and Equipment

O2.1 Unit 2 Containment Closeout Inspection

a. Inspection Scope (IP 71707)

The inspectors performed an inspection of the Unit 2 containment to assess cleanliness and overall safety-related system readiness for unit restart.

b. Observations and Findings

The inspectors, with assistance from the Kewaunee Plant resident inspectors, verified that equipment stored in the Unit 2 containment was appropriately secured. The general cleanliness of the containment was found to be acceptable. No equipment or debris were identified that presented or could present a challenge to the safety-related systems or components within the containment. The inspectors noted minor items involving inadequate securing of small sample piping and miscellaneous trash. The inspectors' findings were provided to outage management for resolution. The total volume of the material identified would not have affected the ability of the emergency core cooling system containment sump recirculation strainer to perform its intended safety functions.

c Conclusions

The inspectors performed an inspection of the Unit 2 containment to assess cleanliness and safety-related system and component readiness for unit restart. Other than minor items which the licensee addressed, the systems, components, and general housekeeping were appropriate for unit startup.

O3 Operations Procedures and Documentation

O3.1 AOP and Emergency Operating Procedure (EOP) Use and Implementation

a. Inspection Scope (IP 71707)

The inspectors documented in IR 50-266/98021(DRP); 50-301/98021(DRP), Section O4.1, that the potential existed for inconsistent operator transient response because of unclear AOP use and implementation guidelines. The inspectors initiated Unresolved Item (URI) 50-266/98021-02(DRP); 50-301/98021-02(DRP) to further evaluate this concern.

b. Observations and Findings

The inspectors reviewed OM Procedure 3.7, "AOP and EOP Procedure Sets Use and Adherence," Revision 5, and identified four areas of concern: the procedure deviation process, immediate operator actions, reference procedure use, and AOP exit requirements. Details of these four concerns are discussed below.

Procedure Deviation Process

Procedure OM 3.7, Sections 2.6, 4.4.3, and 4.5 provided provisions for operators to "deviate" from an AOP or EOP whenever it was necessary to ensure prompt stabilization of the plant and when use of the procedure temporary change process was not practical. The procedure identified circumstances requiring procedural deviations such as when a procedure step needed to be performed in a different manner than presented, or actions were directed that were not contained within the controlling procedure and that were not parallel actions of another procedure. The procedure specified that deviations must have DSS approval, the deviation and reason for it must be logged into the station logbook, and the Duty and Call Superintendent must be notified. In addition, the NRC was to be notified within 1 hour if required by 10 CFR 50.54(x).

The regulations contained in 10 CFR 50.54(x) authorize licensed operators to take action, including the violation of authorized procedures, if such action was deemed necessary to protect the public health and safety. The applicability of 10 CFR 50.54(x) was thus much more narrow than the applicability for procedure deviations specified in OM 3.7. The performance of activities affecting quality in a manner other than as prescribed by written procedure, with the exception of the limited cases covered by 10 CFR 50.54(x), required performance of a procedure change. The requirements for procedure changes were specified in 10 CFR 50.59, and T/S 15.6.8. The licensee's Final Safety Analysis Report (FSAR), Chapter 12.4, "Written Procedures," described AOPs and EOPs. Changes to procedures specified in the FSAR were to be screened or evaluated to ensure that an unreviewed safety question was not created. The licensee classified AOPs and EOPs as "major" procedures. A manager's supervisory staff (the onsite review committee) had to review and approve "intent" changes to major procedures in accordance with T/S 15.6.8.2.A. In addition, "non-intent" changes to major procedures had to receive Duty and Call Superintendent approval in accordance with T/S 15.6.8.3.A. The OM 3.7 procedure deviation process did not address these requirements for procedure changes. Based on the failure of the deviation process to satisfy change requirements for procedures prescribing activities affecting quality, OM 3.7 was considered to be inappropriate to the circumstances, and, as such, an example of a violation (VIO 50-266/99002-01a(DRP); 50-301/99002-01a(DRP)) of 10 CFR 50, Appendix B, Criterion V.

The inspectors also reviewed a licensee document entitled "Guidelines for Consistent Operations." This document was a supplement to OM 3.7 in that it provided additional direction on procedure use and adherence for AOPs and EOPs. Included in this guidance were specific management expectations that operators perform certain EOP steps in a sequence other than as described in the approved EOPs. The inspectors determined that this guidance was not merely a temporary method of implementing previously reviewed and approved changes to the EOPs while the formal changes were being made, rather it was intended to be a permanent change to the EOP. This informal supplement to OM 3.7 was considered to be an additional example of a violation (VIO 50-266/99002-01b(DRP); 50-301/99002-01b(DRP)) of 10 CFR Part 50, Appendix B, Criterion V, in that it represented another procedure change that was not consistent with the regulatory requirements.

Immediate Operator Actions

Plant management expected reactor operators to take certain "immediate" actions specified in the AOPs from memory. The expectation was promulgated through an informal guidance memorandum from the operations manager to operations department personnel. This guidance was deemed necessary to ensure operators took certain actions prior to referencing procedures to avoid a reactor trip. The extent and type of "immediate" actions were not clearly defined or identified for each respective AOP. In addition, the inspectors determined that operations crews inconsistently interpreted the extent of "immediate" operator actions. Also, operations crews were not thoroughly familiar with the expectations from operations department management regarding "immediate" actions.

Reference Procedure Usage

Procedure OM 3.7, Sections 4.9.1, 4.9.4, and Attachment 2 defined and described how operators were to implement procedures referenced in AOP/EOP action steps. The procedures referenced provided the details of how to perform an action or activity. Procedure OM 3.7 stated that the performance of the referenced activity was to be done in accordance with the requirements of the referenced procedure; however, the inspectors noted that the referenced procedure was not required to be obtained or completed. The inspectors determined that this was a deficiency with the OM 3.7 guidance. Specifically, the inspectors were concerned that given the complex nature of some of the AOP and EOP referenced procedural activities, that without the "in-hand" guidance of some of the referenced activities, the operators may not be able to adequately accomplish the required task.

AOP Exit Requirements

The inspectors observed a control room crew implement AOP 6B, "Stuck Rod or Malfunctioning Position Indication Unit 1," Revision 10, on January 24, 1999, in response to an indicated control rod misalignment. When the condition which required AOP entry no longer existed, the crew experienced difficulty in deciding how to exit AOP 6B. The DSS ultimately decided that the entry conditions for AOP 6B no longer existed and; therefore, the AOP no longer applied and would be exited.

The inspectors reviewed OM 3.7, Section 4.2, "AOP and EOP Procedure Set Entry and Exit Requirements," and could not locate any AOP exit requirements or a discussion of under what conditions or how an AOP should be exited. The inspectors discussed the issue with the operations manager, who agreed that OM 3.7 needed clarification.

Licensee's Planned Corrective Actions

The inspectors discussed the above concerns with the licensee. Appropriate corrective actions were planned by the licensee to address each item. Specifically, the licensee planned to remove the procedure deviation provision from OM 3.7, to incorporate all desired actions into the EOPs following completion of formal evaluations and operator training, to provide appropriate procedures to direct any immediate action steps expected of operators, and to review the appropriate method for exiting AOPs and for using referenced procedures. These actions were entered into the plant's corrective action program, and the inspectors considered the specified completion dates to be reasonable.

c. Conclusions

The inspectors identified four areas of concern with the use and implementation of AOPs and EOPs: the procedure deviation process, immediate operator actions, reference procedure use, and AOP exit requirements. Two examples of a violation were identified.

O3.2 Evaluating the Impact of Degraded and Nonconforming Conditions (IPs 37551 & 71707)

During the review of licensee ODs and condition reports (CRs), the inspectors noted that ODs were routinely not performed for nonsafety-related systems, structures, and components. While such reviews are only a regulatory requirement for safety-related equipment or equipment required by T/Ss, occasions exist when performing such a review for other equipment can be beneficial. Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability," guidance stated that licensee should assess the impact of inoperability, degradation, or nonconformance associated with any system, structure, or component described in the FSAR.

The inspectors discussed this issue with the licensee's corrective action organization and with senior plant management. The inspectors referenced the effect of plant staff's failure to assess the impact of inoperable nonsafety-related heat traces in the facade freeze protection system (see IR 50-266/99004(DRP)) as an example of why such assessments could be beneficial. The licensee acknowledged the inspectors observations and were reviewing the issue at the end of the inspection period.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Licensee Event Report (LER) 50-266/97039-00: Residual Heat Removal Loop Inoperable Due to an Inoperable Component Cooling Water Pump. This event was discussed and dispositioned in IR 50-266/97013(DRP); 50-301/97013(DRP), Section O2.2. The LER revealed no new issues.

O8.2 (Closed) LER 50-301/98004: Plant Operation With Reactor Core Power Level in Excess of 1518.5 MWT [megawatts thermal]. On April 24, 1998, the licensee identified that Unit 2 operated with an actual average reactor power of 1519.1 MWT for an 8-hour shift. The condition resulted from the inadvertent return to service of a faulty input into one of the plant computers used to calculate reactor thermal output. The operation of the Unit 2 reactor core at an actual average reactor power of 1519.1 MWT for an 8-hour shift, constituted a violation of Facility Operating License No. DPR-27, Section 3.A, "Maximum Power Levels," which authorized the licensee to operate the facility at reactor core power levels not in excess of 1518.5 MWT. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV) in accordance with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-301/99002-02(DRP)). The inspectors reviewed Root Cause Evaluation 98-100, committed to be performed in the LER, and found it to be acceptable, with recommended corrective actions being entered into the licensee's corrective action program.

O8.3 (Closed) URI 50-266/98021-02(DRP); 50-301/98021-02(DRP): Immediate operator actions. The issue was discussed and dispositioned in Section O3.1 of this report.

O8.4 (Closed) VIO 50-266/99002-01a and b(DRP); 50-301/99002-01a and b(DRP): AOP and EOP use and implementation. The issue was discussed in Section O3.1 of this report.

08.5 (Closed) Escalated Enforcement Item (EEI) 50-266/96018-07a; 50-301/96018-07a: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to remove from the station T/S interpretation manual (Duty & Call Superintendent Handbook) a document that conflicted with T/S 15.3.7 regarding reactor operation with only one 345-kilovolt transmission line in service. The inspectors verified that the corrective actions for this violation were taken, as discussed in the licensee's letter dated October 10, 1997. For this violation, the action was to revise the interpretation manual to remove the conflict with the T/S. In addition, the licensee revised Nuclear Power Business Unit procedure (NP) 5.1.4, "Duty and Call Superintendent Handbook," the governing procedure for T/S interpretations, to explicitly prohibit any interpretations that contradicted or would change the wording, meaning, or intent of any T/S requirement

08.6 (Closed) EEI 50-266/96018-07b; 50-301/96018-07b: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to remove from the T/S interpretation manual a document that conflicted with T/S 15.3.1.A regarding the declaration of the pressurizer power-operated relief valve as inoperable upon placing the control switch to the close position. The inspectors verified that the corrective action for this violation was taken, as discussed in the licensee's letter dated October 10, 1997. For this violation, the action was to revise the interpretation manual to remove the conflict with the T/S.

08.7 (Closed) EEI 50-266/96018-07c; 50-301/96018-07c: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to revise T/S 15.3.4.E regarding the turbine crossover dump system, when the licensee determined that the T/S did not accurately specify the lowest function capability or performance level of the system. As discussed in the licensee's letter dated October 10, 1997, this issue was resolved on August 6, 1997, when the NRC approved the removal of the crossover dump system operability requirement from the T/Ss. The licensee subsequently relocated to the FSAR a revised operability requirement for the system that specified the lowest function capability.

08.8 (Closed) EEI 50-266/96018-07f; 50-301/96018-07f: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure until December 16, 1996, to perform an assessment of the condition identified on December 16, 1994, where there was potentially inadequate protection to prevent the propagation of a single fault in a nonsafety-related backup reactor trip circuit to the reactor protection system circuits. As discussed in the letter dated October 10, 1997, the licensee determined in its evaluation of this issue on December 16, 1996, that no fault in the backup reactor trip circuit could disable both trains of the reactor protection system.

08.9 (Closed) EEI 50-266/96018-07p; 50-301/96018-07p: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to promptly correct a condition adverse to quality identified in 1994 regarding nonsafety-related cable separation and breaker thermal overload capability for circuits connected with the control of main steam isolation valve closure and engineered safety feature signal generation. The licensee replaced the suspect breakers with a model that had a more reliable magnetic trip element.

O8.10 (Closed) IFI 50-301/97016-03: Water hammer in the Unit 2 auxiliary feedwater system. The licensee installed new "first off" check valves (AF-100 and AF-101) during the Unit 2 refueling outage. The new valves are corrective action for pressure pulsations in the auxiliary feedwater system. The previously installed swing check valves were believed to be the source of these pressure pulsations.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Refueling Outage Frequency Surveillance Tests

a. Inspection Scope (IP 61726)

The inspectors observed major portions of several refueling outage surveillance tests.

b. Observations and Findings

Operations Refueling Test (ORT) 3A

The inspectors observed the licensee staff implement ORT 3A, "Safety Injection Actuation with Loss of Engineered Safeguards AC [alternating current] (Train "A")," on February 11, 1999. The inspectors also attended the pre-job briefing held on February 9, 1999. The pre-job briefing was thorough and effective. During the briefing, the test director stated that if an "off-normal" event occurred during the surveillance test, the on-shift operating crew would resume control of the plant equipment and the test crew would provide assistance as requested.

With one exception, which is described below, the surveillance test was performed well. An adequate number of personnel were assigned (16 test stations were manned). All involved personnel used three-way communications. The test coordinator provided clear and unambiguous instructions to all involved personnel. All equipment performed its design safety function within the test acceptance criteria.

At one point during the performance of ORT 3A, the Unit 2 "A" train emergency diesel generator output breaker was briefly opened and then re-closed. During this portion of the test, the Unit 1 "A" train emergency diesel generator (G-01) was carrying the load on the Unit 2 "A" train 4160-volt (2A-05) and 480-volt (2B-03) safety-related buses. When the operator attempted to re-close the output breaker it did not shut resulting in a complete loss of power to buses 2A-05 and 2B-03. The ORT 3A procedure provided no contingency to address this condition.

Following recognition that all power had been lost to the safety-related buses, a discussion ensued in the control room regarding the next actions to be taken. The inspectors heard someone ask whether entry into the AOPs was necessary, but heard no response. The inspectors observed that the test personnel remained at the C01 and C02 main control boards, and continued to provide the test director with information required by the test procedure. The on-shift operating crew did not appear to be taking any specific action in response to the unexpected, off-normal, condition. This was not consistent with the expectation, stated during the pre-job briefing, that the crew would take command of the unit during any off-normal event. After some time had passed, the inspectors asked the test director why the operators had not yet entered the AOP for a loss of power to safety-related buses. The on-shift crew took command of the control boards and entered the appropriate AOPs shortly thereafter.

The total time elapsed between loss of power to 2A-05/2B-03 and its restoration was 69 minutes. The crew ultimately decided that the G-02 output breaker was in a "tripped-free" state that could only be reset by taking the control switch back to "pull-to-lock." The test crew, under the direction of the on-shift DSS, re-performed the step in ORT 3A that specified taking the breaker to "pull-to-lock." This time the G-01 output breaker closed when it was returned to the "auto" position. The test crew then completed ORT 3A.

The inspectors observed that the control room operators were appropriately deliberative in reviewing the available options, and the potential consequences for each option, in response to the loss of power to the safety-related buses. There was also adequate staffing of the control room to allow the operating crew to respond to the situation while support personnel reviewed the applicable technical specifications and evaluated reportability. On the other hand, the on-shift operating crew's delay in exiting the test procedure and entering the applicable AOP (given the absence of contingency instructions in the ORT) was a concern to the inspectors. A second concern was that the DSS became actively involved in responding to the loss of power. This was not consistent with the licensee's expectations for the conduct of operations. Specifically, the inspectors understood that the DSS's responsibility was to monitor the performance of the operating supervisor and the duty operating supervisor, as well as the control board operators. Rather than maintaining this "big picture" role, the DSS appeared to be assuming the responsibilities of the operating supervisor.

The inspectors were also concerned that re-energization of the buses appeared to be slowed by a partial focus on completing the ORT 3A test. Plant operators had restored power to de-energized "B" train safety-related buses on two units following a surveillance test related problem on July 7, 1997 (LER 50-266/97034; 50-301/97034). During the 1997 event, the inspectors had observed that the focus of control room operators was clearly on restoring power to the affected buses. Considerations associated with the test being performed at the time did not contribute to a delay in restoring power to the affected buses. During the 1999 event, the inspectors concluded that the operators' focus was, in part, on completing the ORT 3A test. In both the 1997 and 1999 cases, the operators were appropriately deliberative in ensuring that actions being taken were not going to create more significant safety problems. This necessary deliberativeness was not a concern to the inspectors. The licensee subsequently determined that the test coordinator, a non-licensed individual, contributed to the mixed focus on the part of the crew. This conclusion was consistent with the inspectors' observations.

The "tripped-free" problem with the emergency diesel generator output breaker was well known to the licensee. A modification initiated in 1995 was designed to address this issue. The modification had been scheduled for completion prior to the performance of ORT 3A, however, it had been delayed. The modification was subsequently completed prior to unit restart.

ORT 3B

The inspectors observed the performance of ORT 3B, "Safety Injection with Loss of Engineered Safeguards AC (Train B)," on February 12, 1999. The pre-job brief for this surveillance test addressed corrective actions for the loss of power experienced during performance of ORT 3A. Performance of ORT 3B was characterized by the same high quality communication techniques observed during performance of ORT 3A. All equipment worked as expected, and all acceptance criteria were satisfied.

ORT 3C

February 9, 1999, The inspectors observed the performance of ORT 3C, "Auxiliary Feedwater System and AMSAC [anticipated transient without SCRAM mitigating system actuation circuit] Actuation Unit 2," Original Revision. This ORT tested the automatic response of the AFW system in response to a steam generator low-low level indication; automatic response of the AFW system in response to a low AFW pump suction pressure condition; automatic operation of the AFW system following an AMSAC signal; automatic steam generator blowdown isolation in response to an AFW pump start; and valve closure inhibit circuitry for AFW pump discharge pressure control valves.

The inspectors observed the conduct of the AFW system testing from the control room. The test director (a senior reactor operator) conducted a thorough pre-job briefing which clearly identified individual responsibilities for the test and contingency plans in the event of abnormal occurrences.

During the conduct of the test, a reactor operator noted that the discharge pressure control valve for the "B" AFW pump was slow to open compared to the equivalent valve for the "A" pump. The operator conveyed this observation to control room supervision who subsequently timed the valves opening during a later portion of the test and ultimately declared the affected valve (AF 4019) and thus, Train "B" of the AFW system, inoperable pending resolution of the slow valve opening times. A later engineering evaluation revealed that the valve performed within acceptable criteria for the train to perform its intended safety function; however, a good example of questioning attitude and conservative decision-making was illustrated by the operations test crew in identifying the potential problem.

As the test progressed other problems were encountered involving the "B" steam generator supply valve to the Unit 2 steam-driven AFW pump. This problem, compounded with the concerns with the operability of the Train "B" AFW, led the test director to abort the test. A plan was established and appropriately implemented which ended the testing.

The test was re-conducted on February 13, 1999, no problems were encountered and all equipment performed satisfactorily.

c. Conclusions

Routine portions of two major refueling outage frequency surveillance tests were conducted well. All safety-related equipment functional requirements were satisfied. Operators displayed good questioning attitude regarding the performance of safety system valves, and the operations test director suspended the testing activity during a third surveillance test.

During a portion of one test, operators failed to promptly enter applicable AOPs following an unanticipated loss of power to safety-related buses. Operator response to the loss of power was impacted by conflicting focuses on recovering the buses and completing the test. The DSS became involved in solving the power problem rather than maintaining the aloof oversight position expected by the licensee.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unit 2 Refueling Outage Modifications and Repairs

The licensee completed many important to safety modifications during the 1999 Unit 2 refueling outage. Examples included reactor vessel baffle bolt replacement, main control board wire separation, and over-pressure protection for containment penetrations and motor-operated valves.

The inspectors also reviewed all 23 main control room work order stickers for Unit 2 on February 14, 1999. Each work order had been screened for safety significance within the licensee's work order process. The inspectors did not identify any condition which should have been corrected prior to start-up. Notwithstanding the lack of safety significance, the fact that the licensee exited a major refueling outage with open control room instrumentation work orders written over a year ago illustrated the magnitude of the corrective and preventive maintenance backlog and necessary modification work at the facility.

M2.2 Conduct of Maintenance during the Refueling Outage

a. Inspection Scope (IP 61726, 71707, & 62707)

The inspectors observed the performance of various maintenance and surveillance test activities, and monitored the status of plant equipment during the post-maintenance testing performed near the end of the Unit 2 refueling outage.

b. Observations and Findings

Several equipment problems were experienced during post-maintenance testing and periodic surveillance testing of Unit 2 equipment. Examples included repeat bearing failures of the "B" train safety injection pump (2P-15B) motor, failure of the "A" train safety injection pump (2P-15A) seal, and failures of safety-related valves (SI-897 and SI-857).

An additional problem encountered during Unit 2 start-up preparations was associated with the nonsafety-related CVCS. A cleaning rag left in the CVCS system during maintenance work caused a water hammer transient when it became lodged in, and then passed through, a flow orifice. Most of the rag was retrieved from the seat area of a CVCS valve downstream of the flow orifice. The licensee performed extensive system flushes and diagnostic tests to identify any other problems associated with this foreign material. An extensive review of the potential impacts of any remaining pieces of rag were also performed. The licensee ultimately concluded that any remaining rag pieces would not affect the safe operation of the plant. The inspectors considered the licensee's evaluation to be thorough. However, the event illustrated potential weaknesses in the implementation of foreign material exclusion program requirements and the rigor applied to contract worker oversight.

The licensee initiated a root cause evaluation for the foreign material in the CVCS system, and was evaluating a common cause evaluation for the increased failure of safety-related equipment following maintenance activities.

c. Conclusions

There were several examples of safety-related equipment that failed post-maintenance testing and periodic surveillance tests and an instance where foreign material (pieces of a cloth rag) was left in the reactor coolant system after maintenance activities and caused a minor water hammer in the chemical and volume control system. The maintenance-related problems were more significant than those observed during previous outages.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) LER 50-266/98010-00 and 50-266/98010-01; 50-301/98010-00 and 50-301/98010-01: Inadequate Technical Specifications Surveillance of Containment Spray Logic. On February 13, 1998, the licensee identified that portions of the containment spray logic circuits were not being tested on a quarterly frequency in accordance with T/S Table 15.4.1-1, Item 27, "Containment Pressure." These logic circuits were subsequently tested with satisfactory results. The inspectors verified the corrective actions described in the LER were completed by the licensee. The failure to perform quarterly testing of portions of the containment spray logic circuits constituted a violation of T/S 15.4.1, which required the circuits be tested quarterly. This non-repetitive, licensee-identified and corrected violation is being treated as an NCV in accordance with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-266/99002-03(DRP); 50-301/99002-03(DRP)).

III. Engineering

E1 Conduct of Engineering

E1.1 Engineering Department Response to Continuing Lubrication Control Issues

a. Inspection Scope (IPs 37551 & 40500)

The inspectors reviewed the licensee's efforts in addressing continuing problems with the control of lubricants. This review included an assessment of the licensee's corrective actions.

b. Observations and Findings

Lubrication Control Problems

An inspector review of condition reports revealed that the licensee had documented several occurrences of improper lubricants being used for safety-related equipment in 1998. Each reported occurrences was evaluated and either the correct lubricant was subsequently used or an engineering evaluation was performed to verify that the incorrect lubricant was acceptable for use on the affected component. The reported uses of incorrect lubricants were dealt with on an individual basis; however, no broad scope assessment of the lubricant control program was initiated by the licensee.

On December 27, 1998, a condition report was written identifying discrepancies between the computer database equipment listings of lubricants and the licensee's lubrication manual. The specific discrepancy referenced in the condition report pertained to oil for the Unit 1 and 2 emergency diesel generator governors. On December 30, the wrong lubricant was added to the Unit 2 emergency diesel generator governor. At the daily manager's meeting conducted the same day, the Site Vice President requested that a root cause evaluation be performed to assess the lubrication control problem at the station.

The lubrication manual contents were compared to the information contained in the station equipment database. Some discrepancies were identified during the licensee's review; however, none of the problems affected equipment operability. The licensee and the inspectors concluded that the licensee had not previously assessed the programmatic implications of the lubrication control problems until numerous errors had occurred.

Lack of Engineering Review Thoroughness

As part of the root cause evaluation, the licensee identified that the environmental qualification maintenance requirements for lubricants on some safety-related motors had not been met. This issue dealt with service life of lubricants in sealed-for-life bearings in safety-related applications such as the residual heat removal system pump motors. The inspectors were concerned that this issue was not recognized earlier. It had been previously discussed by the resident inspectors with the responsible engineer in April 1998 (IR 50-266/98005(DRP); 50-301/98005(DRP), issued May 5, 1998). Based on the content of licensee documents from May 1998, the inspectors believed that more rigorous follow-up or more effective communications between the component engineering group and the environmental qualification engineering group would have resulted in a more timely resolution of the potential problem.

Based on the specific circumstances of this condition, the inspectors concluded that it represented a weakness within the licensee's engineering organization rather than a regulatory non-compliance. At the time of the inspection, the lubrication issues appeared to be receiving appropriate attention within the licensee's corrective action program.

c. Conclusions

The licensee was slow to recognize generic weaknesses in the programs for controlling the use of lubricants in safety-related applications. Examples of the problems included inconsistencies in various licensee documents, and poor follow-through by engineering staff or poor communications between engineering groups when addressing lubrication issues.

E2 Engineering Support of Facilities and Equipment

E2.1 Load Evaluation for Unit 2 480-Volt Safety-Related Bus 2B-03 and 2B-04 Crosstie

a. Inspection Scope (IP 37551)

The inspectors reviewed the licensee's evaluation of the cross-connection of the Unit 2 480-volt safety-related buses, 2B-03 and 2B-04.

b. Observations and Findings

The licensee de-energized the Unit 2 4160-volt safety-related bus 2A-05 for modification and cleaning during the Unit 2 refueling outage. To power the 480-volt safety-related bus 2B-03 loads, which were normally supplied from 2A-05, the licensee cross-tied 2B-03 with another 480-volt safety-related bus (2B-04). Section B.1.e.1 of T/S 15.3.7, "Auxiliary Electrical Systems," required the licensee to perform an evaluation to show that the loads that remained or could be energized by the buses would not cause a potential overload of the associated diesel generator.

The licensee performed Calculation Number 98-0111, "480 Volt Bus 2B03, 2B04 Tie Loading Analysis," Revision 0, to satisfy the T/S. In addition to evaluating diesel generator loading, the calculation also evaluated the potential loading upon the buses, transformers, and cabling, as well as protective device settings. The calculations were well documented and thorough. The inspectors independently verified portions of the licensee's assumptions and determined them to be appropriate.

Calculation 98-0111 determined certain restrictions on plant configuration would be required if buses 2B-03 and 2B-04 were to be cross-tied. The restrictions included removal from service of one service water pump supplied from the cross-tied buses and not allowing the diesel generator that was aligned to automatically provide power to the cross-tied buses to be aligned to supply any Unit 1 safeguards bus. The inspectors verified the licensee properly implemented these restrictions when 2B-03 and 2B-04 were cross-tied.

c. Conclusions

The inspectors determined that the licensee's evaluation to cross-tie safety-related 480-volt buses was thorough and well documented. Equipment configuration restrictions specified in the evaluation were verified by the inspectors to have been properly implemented by the licensee.

E7 Quality Assurance (QA) in Engineering Activities

E7.1 QA Audit of Station-wide Corrective Action Program (IPs 37551 & 40500)

The inspectors attended a QA exit meeting held on February 5, 1999, which presented results of a completed audit of the station's operating experience, vendor technical information, and corrective action programs. The inspectors noted that the depth and breadth of the audit was sufficient to identify strengths and deficiencies within the audited programs. The operating experience and vendor technical information programs were found to be adequately implemented with areas for improvement identified. The corrective action program was determined to be adequate; however, many areas warranted further management attention, including thoroughness of root cause evaluations, timeliness of corrective actions, and effective trending of reported problems. Many of the findings were similar to those identified by the inspectors in past IRs. A further review of the corrective action program is documented in IR 50-266/99005(DRS); 50-301/99005(DRS).

E8 Miscellaneous Engineering Issues

E8.1 (Closed) EEI 50-266/96018-07d; 50-301/96018-07d: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure from April 1993 to February 1997 to correct a condition adverse to quality where the 1P-15B safety injection pump, powered from a lightly loaded emergency diesel generator with speed droop set, would run at higher frequency and current, potentially tripping on overcurrent. The licensee subsequently modified the G01 and G02 diesels (in July 1997 and February 1998, respectively) to replace the hydro-mechanical governor with the speed droop feature, thereby eliminating the potential for elevated frequency operation of the safety injection pump motor. The licensee's other diesels, G03 and G04, had already been provided with an electronic load-sharing governor (no speed droop) to ensure operation at the nominal frequency of 60 hertz under all operating conditions. Since the modification of the G01 and G02 diesels, the safety injection pump has not tripped because of overcurrent during surveillance testing.

E8.2 (Closed) EEI 50-266/96018-07e; 50-301/96018-07e: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure until December 16, 1996, to perform an assessment of the condition identified on December 22, 1994, where backup reactor trip circuits did not meet safety-related train separation requirements, possibly affecting those circuits during postulated single-failure events. As discussed in the licensee's response to this issue, the FSAR was revised to include the technical justification for not meeting the separation requirements. In addition, as with the other examples of the corrective action escalated enforcement items from IR 50-266/96018; 50-301/96018 discussed in Sections O8 and E8 of the current inspection report, the licensee has discussed with the appropriate plant staff the need to take prompt, comprehensive corrective actions when conditions adverse to quality are identified.

E8.3 (Closed) EEI 50-266/96018-07g; 50-301/96018-07g: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure until December 19, 1996, to perform an assessment of the condition identified on December 16, 1994, where instruments of lesser accuracy than original margins had accounted for may have resulted in nonconservative T/S setpoints for five reactor protection system trip parameters. The licensee subsequently determined in its evaluation that the trip parameters were within the required limits considering instrument accuracy.

E8.4 (Closed) EEI 50-266/96018-07h; 50-301/96018-07h: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure until December 16, 1996, to assess a condition adverse to quality identified in January 1996, where nonconservative operation of the containment condensate measuring system may have resulted in the inability to detect a one gallon per minute leak of reactor coolant within four hours. The inability to measure this leak rate was contrary to the licensee's response to NRC Generic Letter 84-04, "SE of Westinghouse Topical Reports Dealing with the Elimination of Postulated Pipe Breaks in PWR Primary Main Loops." The licensee subsequently determined in its evaluation that the condensate measuring system performance capability was within the specified limits and that the system fulfilled the requirement of T/S 15.3.1.D.7 as a reactor coolant leak detection system.

E8.5 (Closed) EEI 50-266/96018-07i; 50-301/96018-07i: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure until December 16, 1996, to assess a condition adverse to quality identified in January 1996, where replacement backdraft dampers for containment fan coolers may have only been analyzed for static conditions and not for the dynamic forces following a loss-of-coolant accident (LOCA). From an evaluation of the original Bechtel design documents, the FSAR, and the inplant system configuration, Sargent and Lundy determined for the licensee that the backdraft dampers would not be damaged during a LOCA.

E8.6 (Closed) EEI 50-266/96018-07j; 50-301/96018-07j: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure until December 11, 1996, to assess a condition adverse to quality identified in January 1995, where original Bechtel design calculations lacked evidence that the seismic analysis for containment was considered in the design for the shield walls and intermediate concrete slabs and support steel. A subsequent evaluation (Calculation 10447-9611-001) of containment internal structures for seismic loads by Bechtel, the original plant architect, indicated that seismic loads did not govern containment floor design; that the primary and secondary shield walls were adequate for shears, bending moments, and axial loads from the containment seismic analysis; and that the connections between the secondary shield walls and the containment floor slabs were adequate to transfer floor slab horizontal loads, with vertical seismic loads being carried by the structural steel supporting the slabs.

E8.7 (Closed) EEI 50-266/96018-07k; 50-301/96018-07k: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure until December 13, 1996, to assess a condition adverse to quality identified in April 1995, where main feedwater flow would be lost immediately during a small-break

LOCA accident instead of after two seconds as assumed in accident analyses. The licensee's evaluation included an assessment by the reactor vendor that the effect of minimum versus maximum main feedwater system isolation delays usually had only a small effect on the computed peak clad temperature parameter of concern in small-break LOCA analyses.

E8.8 (Closed) EEI 50-266/96018-07l; 50-301/96018-07l: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure until December 13, 1996, to assess a condition adverse to quality identified in March 1993, where the fault currents for five safety-related 480-volt motor control centers could potentially be larger than the interrupting capability of the breakers. This issue was subsequently pursued by the licensee as a 10 CFR Part 50, Appendix R concern, for which LER 50-266/97-032; 50-301/97-032 was issued. The LER was subsequently closed by the NRC and the issue of inadequate interrupting capability is currently being tracked as EEI 50-266/97022-02; 50-301/97022-02.

E8.9 (Closed) EEI 50-266/96018-07m; 50-301/96018-07m: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure on or around June 14, 1995, to correct T/S Table 15.3.5-1 when the licensee identified that proposed loss-of-voltage relay settings (which were subsequently incorporated into the Table) were nonconservative. The licensee had identified one low probability scenario in which there might be a lack of breaker coordination between 4160-volt and 480-volt breakers with an emergency diesel generator operating. Instead of changing the T/S, the licensee opted to change the relays to resolve the issue, completing the last of the modifications during the recently completed Unit 2 refueling outage.

E8.10 (Closed) EEI 50-266/96018-07n; 50-301/96018-07n: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to properly correct an NRC-identified error in a calculation for the loss-of-voltage relays. The licensee revised the calculation to correct error and counseled the individual involved in the error on the need for conservative decision-making and for attention-to-detail.

E8.11 (Closed) EEI 50-266/96018-07q; 50-301/96018-07q: An example of an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure from October 14, 1996, to January 9, 1997, to test two Unit 1 spare containment penetrations that the licensee identified on October 14 as not having been tested since 1995. The testing of the penetrations was reviewed as part of the NRC closeout of LER 50-266/97002; 50-301/97002 in IR 50-266/98009(DRP); 50-301/98009(DRP). The need for taking prompt corrective actions has been emphasized to plant staff by station management. Inspections during the latter half of 1997 and in 1998 have indicated a significant improvement in the licensee's identification and correction of issues.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

Throughout the inspection period, the inspectors observed radiological control postings and radiation protection technician performance during tours of the radiologically controlled area, including Unit 2 containment. All postings and surveys for radiological areas were appropriate and current, and technicians provided appropriate radiological oversight of work activities.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on February 22, 1999. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Wisconsin Electric Power Company

C. R. Peterson, Director of Engineering
D. P. McCloskey, Maintenance Manager
J. G. Schweitzer, System Engineering Manager
J. R. Anderson, Operations Manager
M. E. Reddemann, Site Vice President
R. G. Mende, Plant Manager
R. P. Farrell, Radiation Protection Manger
V. M. Kaminskas, Regulatory Services and Licensing Manager

NRC

B.A. Wetzel, Point Beach Project Manager, NRR

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 60855:	Operation of an ISFSI
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-266/99002-01a(DRP) 50-301/99002-01a(DRP)	VIO	AOP and EOP use and implementation
50-266/99002-01b(DRP) 50-301/99002-01b(DRP)	VIO	AOP and EOP use and implementation
50-301/99002-02(DRP)	NCV	Operation of the Unit 2 reactor core at an actual average reactor power of 1519.1 megawatts thermal for an eight-hour shift
50-266/99002-03(DRP) 50-301/99002-03(DRP)	NCV	Failure to perform quarterly testing of portions of containment spray logic circuits

Closed

50-266/97039-00	LER	Residual heal removal loop inoperable due to an inoperable component cooling water pump
50-301/98004	LER	Plant operation with reactor core power level in excess of 1518.5 megawatts thermal
50-301/99002-02(DRP)	NCV	Operation of the Unit 2 reactor core at an actual average reactor power of 1519.1 megawatts thermal for an eight-hour shift

50-266/98021-02(DRP) 50-301/98021-02(DRP)	URI	Immediate operator actions
50-266/99002-01a(DRP) 50-301/99002-01a(DRP)	VIO	AOP and EOP use and implementation
50-266/99002-01b(DRP) 50-301/99002-01b(DRP)	VIO	AOP and EOP use and implementation
50-266/96018-07(DRP) 50-301/96018-07(DRP) (all items except 07o)	EEI	Appendix B, Criterion XVI problems
50-266/98010-00,01 50-301/98010-00,01	LER	Inadequate Technical Specification surveillance of containment spray logic
50-266/99002-03(DRP) 50-301/99002-03(DRP)	NCV	Failure to perform quarterly testing of portions of the containment spray logic circuits
50-301/97016-03(DRP)	IFI	Water hammer in the Unit 2 auxiliary feedwater system

<u>Discussed</u>

50-266/97022-02(DRP) 50-310/97022-02(DRP)	EEI	Secondary fire potential created by inadequate breaker capability

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
AOP	Abnormal Operating Procedure
CFR	Code of Federal Regulations
CR	Condition Report
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
DSS	Duty Shift Superintendent
EOP	Emergency Operating Procedure
FSAR	Final Safety Analysis Report
IFI	Inspection Followup Item
IP	Inspection Procedure
IR	Inspection Report
LER	Licensee Event Report
LOCA	Loss-of-Coolant Accident
MWT	Megawatts Thermal
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OD	Operability Determination
OM	Operations Manual
OP	Operating Procedure
ORT	Operations Refueling Test
PDR	Public Document Room
PPCS	Plant Process Computer System
QA	Quality Assurance
RCP	Reactor Coolant Pump
T/S	Technical Specification
URI	Unresolved Item
VIO	Violation