U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Wisconsin Electric Power Company, WEPCO
Facility:	Point Beach Nuclear Plant, Units 1 & 2
Location:	6612 Nuclear Road Two Rivers, WI 54241-9516
Dates:	July 27 through September 8, 1997
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C-11

EXECUTIVE SUMMARY

Point Beach Nuclear Plant, Units 1 & 2

NRC Inspection Report No. 50-266/97016(DRP), 50-301/97016(DRP), 72-005/97016(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week inspection period by the resident inspectors, regional inspectors, and a representative of the Office of Nuclear Reactor Regulation.

Operations

- The quality of logkeeping observed by the inspectors indicated additional management attention is warranted in this area. Examples of some inconsistencies between control room operators concerning the detail and completeness of the unit log entries were noted by the inspectors. Auxiliary operator logs were at times incomplete and lacked details of equipment evolutions that occurred during the shifts.

- Control room operators showed significant improvement in command and control, procedural adherence, and communications during observations of the recent Unit 2 reactor startup compared to performance in 1996 and early 1997 (Section O4.1).

- Notable improvement was observed in the depth of questioning of program problems and the overall conduct of the most recent Off-Site Review Committee meeting compared with a spring 1997, meeting (Section O7.1).

- Four examples of a violation of NRC corrective action requirements were identified and were attributed to a significant deficiency in the licensee's tracking and timeliness of identified actions for NRC commitments (Section O8.1).

Maintenance

- On two occasions, a Technical Specification violation occurred due to equipment failures which rendered a residual heat removal loop inoperable. For one of the occasions, involving a crack in a component cooling water pipe in July 1997, corrective actions to address a crack in the same pipe in October 1996 were not comprehensive enough to prevent the July 1997 failure (Section M2.2).

Engineering

- The engineering organization performed well in identifying and assessing technical concerns during the reporting period. Plant management took appropriate, conservative actions, including shutting down Unit 2, to address concerns (Section E1.1).

- On August 25, 1997, licensee heard possible water hammer noise in the auxiliary feedwater system. The inspectors did not identify any concerns with the licensee's response to this issue (Section E2.1).

- Two examples of a violation of NRC test control requirements were identified by the inspectors for the failure to include test acceptance criteria in inservice testing and maintenance procedures. This issue is not unique to these two procedures and resolution will require a programmatic corrective action effort (Section E3.1).

Plant Support

- Contaminated boric acid crystals were discovered on the residual heat removal cross-connect valves by the inspectors. Ample opportunity had existed for health physics technicians and operators to identify the contamination, bringing into question the sensitivity and thoroughness of these workers while performing duties and rounds in the auxiliary building (Section R1.2).

- A licensee-identified failure to lock the lower equipment door to the Unit 2 containment, was another example of recent high radiation area posting, entry, and control problems at the station. A Technical Specification violation was identified (Section R1.3).

- On August 15, 1997, security personnel failed to take required compensatory action for a failed or degraded safeguards system. Two other events involving failed or degraded safeguards systems with inadequate compensatory measures have been identified during the past two years (Section S1.1).

Report Details

Summary of Plant Status

During this inspection period, Unit 1 remained in cold shutdown. Unit 2 was started up following completion of refueling outage 2R22 and the main generator was placed on-line on August 16, 1997. This 10-month outage included installation of new steam generators and the resolution of a large number of licensee commitments, as documented in a Confirmatory Action Letter dated January 3, 1997. Unit 2 reached 100 percent power on August 24, 1997. On September 6, 1997, Unit 2 was shut down to resolve a potential undervoltage condition on the "A" train 480-volt (V) safety-related buses. This condition could occur when either emergency diesel generator (EDG) G01 or G02 was supplying power to the buses during certain loss of coolant accidents with a loss of offsite power.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

During the inspection, the inspectors frequently reviewed ongoing plant operations including observing daily Unit 1 and Unit 2 control room shift turnovers and control room operations.

Control room operators continue to show significant improvement in command and control and communications from 1996 and early 1997. Control room control board attentiveness was very good throughout the inspection period, especially during the Unit 2 start-up.

Control room staffing levels have improved over the past six months and were consistent with Operations Manual [OM] 1.1, Revision 1, "Conduct of Plant Operations," expectations and requirements. Three control (reactor) operators (COs) were observed by the inspectors in the control room at all times during the inspection period. Generally, three senior reactor operators (SROs) were also in the control room during Unit 2 start-up. One SRO was always designated for only Unit 2 oversight during the start-up.

The inspectors noted that significant challenges remain with updating operations procedures and providing quality documents that can be worked as written (See Section O3.1). The inspectors noted several inadequacies with procedures used to restart Unit 2 in August and for the shutdown on September 6, 1997, and operations management documented in Condition Report [CR] 97-2532 that an abnormal operating procedure was not updated with recent Technical Specification (TS) changes. The inspectors concluded that substantial work remains to upgrade existing operations procedures and operations management has committed extensive resources to the upgrade program.

Although procedural adherence was excellent during the Unit 2 restart, the inspectors observed that adherence was only adequate during shutdown in that a procedurally recommended process for making changes to procedures was not always followed. Specifically, the inspectors noted that operators were performing procedural steps in parallel with making procedural step changes when changes were required. During restart, the inspectors had observed operators waiting until after a change had been made prior to performing a step that was changed.

The inspectors noted that the quality of logkeeping by operators ranged from very good to barely adequate. The station log kept by the Duty Shift Supervisor (DSS, the lead supervisory SRO) was generally very good with good detail of the information required by OM 1.1. The Unit CO log was generally good and contained a fairly good narrative of the overall operation of the Unit, consistent with OM 1.1. Some inconsistency between COs regarding the detail and completeness of the Unit logs entries was noted by the inspectors. The inspectors noted that the auxiliary operator (AO) logs, however, were often incomplete and lacked details of evolutions that occurred for the watchstation. The inspectors concluded that the AO logs barely met the expectations of OM 1.1.

O3 Operations Procedures and Documentation

O3.1 Reactor Engineering Procedure Problems During Unit 2 Low Power Physics Testing

a. Inspection Scope (71711)

The inspectors noted problems with the adequacy of Reactor Engineering Surveillance Procedure [RESP] 4.1, Revision 12, "Initial Criticality and All Rods Out (ARO) Physics Tests" during Unit 2 low power physics testing.

b. Observations and Findings

During Unit 2 low power physics testing, deficiencies were noted within RESP 4.1. In one instance, the procedure required a multi-pen recorder pen position be at 25 percent (specified value). When operators and reactor engineers attempted to set up the plant conditions required by the test, it became difficult to meet the requirements for the recorder pen position. In another instance, the procedure required the use of the computer for rod position indication rather than the values available to the operators from other control room instrumentation. In both of these cases, significant delays in the reactor startup occurred while personnel were contacted to either make procedural changes or establish methods to meet the rigidly specified procedural requirements. These problems illustrated that recent procedural improvements may have included requirements that were too restrictive for the actual test conditions.

c. Conclusions

The inspectors concluded that some of the procedures used during low power physics testing contained overly restrictive steps. However, plant personnel were observed to have taken the appropriate steps to comply with the procedures or have the procedures revised as necessary.

04 Operator Knowledge and Performance

O4.1 Unit 2 Reactor Startup

a. Inspection Scope (71707 & 71711)

The inspectors provided continuous oversight of operations activities for the Unit 2 restart from the approach to criticality through the power ascension to approximately 50 percent power. During this inspection, the inspectors reviewed the following documents:

- OM 1.1, Revision 1, "Conduct of Plant Operations"
- RESP 3.1, Revision 12, "Primary System Tests"
- RESP 4.1, Revision 12, "Initial Criticality and All Rods Out (ARO) Physics Tests"
- RESP 4.2, Revision 9, "Control Rod Reactivity Worth Measurements"
- RESP 5.1, Revision 11, "Reactor Engineering Tests from 0 percent to 30 percent Power"
- RESP 5.2, Revision 9, "Reactor Engineering Tests During Escalation to Full Load"
- Operations Procedure [OP] 1A, Revision 59, "Cold Shutdown to Hot Shutdown"
- OP 1B, Revision 29, "Reactor Startup"
- OP-1B, Appendix A, Revision 6, "Estimated Rate Position Calculation"
- OP 1C, Revision 60, "Lower Power Operation to Normal Power Operation"

b. Observations and Findings

On August 13, 1997, at 6:29 p.m. the Unit 2 reactor was made critical. Around the clock coverage was provided by the inspectors during the approach to criticality through power ascension to 50 percent rated thermal power.

The inspectors observed several special briefings for activities categorized as infrequently performed tests or evolutions. These briefings were very good as illustrated through the use of procedural notes, emphasis on cautions and limitations, communications, roles and responsibilities of personnel, and contingency actions.

Performance of the operators during the approach to criticality and low power physics testing was very good as illustrated by consistent three-way communications and good control board monitoring and attentiveness. Command and control was generally very good as plant "maneuvering" was directed by the SRO specifically assigned to Unit 2. Some minor difficulties were noted during core physics reactivity manipulations. Operation's Manual procedure 1.1 "Conduct of Operations" specified that SROs were required to direct all reactivity manipulations. During this aspect of testing, the cognizant reactor engineer provided most of the information for reactivity manipulation. The need to include input from the reactor engineer as part of the reactivity manipulations presented challenges to the SROs in maintaining active control as required by OM 1.1.

Control room access was limited during the startup to reduce operator distraction; however, one weakness in access control occurred when a sign was placed on the control room access door indicating that after being granted access to the control room, entry was to be between the control room panels. This was done to limit the number of people in the area of the reactivity recorder and where reactivity manipulations were being conducted. Frequently, however, personnel entered the control room via the normal path rather than going around and entering between the panels as indicated by the sign. In addition, control room SROs did not correct individuals who did not enter properly. The inspectors noted that the number of phone calls coming into the control room during a reactor startup seemed high.

Steam generator (SG) blowdown was one of the major challenges as Unit 2 ascended in power. When operators tried to increase blowdown to improve secondary chemistry, the blowdown throttle valves and strainers plugged and limited blowdown flow. The licensee determined that this plugging was caused by impurities removed from the SGs during heatup due mainly to the SG chemical passivation process used to protect the new SGs. The inspectors observed that although this condition delayed clearing the chemistry hold at 30 percent power, operators adequately addressed this challenge during start-up.

c. Conclusions

Control room operators continue to show significant improvement in command and control and communications when compared to performance in 1996 and early 1997.

O7 Quality Assurance in Operations

O7.1 Plant Off-Site Review Committee (OSRC) Meeting Observations

Portions of the OSRC Meeting were observed by the inspectors from August 5 through August 7, 1997. Throughout the meeting, the inspectors noted OSRC members frequently asking challenging questions of the departmental programs under review. The inspectors noted that the level of in-depth questioning of program problems was generally good; however, during some program reviews the depth of questions was shallow and emphasis was not placed on programmatic challenges. Overall, the inspectors noted substantial improvement in the conduct of the OSRC compared to the OSRC meeting observed in the spring 1997.

O7.2 Condition Report System Review

a. Inspection Scope (71707)

The inspectors performed additional reviews of the changes the licensee has made to the CR program in 1997. The inspectors reviewed licensee provided materials, CRs, and the following documents:

- Quality Assurance (QA) Audit Report Number A-P-97-06, "Corrective Actions and Operating Experience"

- Nuclear Power Business Unit Procedure [NP] 5.3.1, Revision 5, "CR System"
- NP 5.3.2, Revision 4, "Industry Operating Experience (OE) Review Program"
- NP 5.4.1, Revision 1, "Open Item Tracking Systems"
- QA Condition Report [QCR] 97-118, "NP 5.4.1 Does Not Adequately Address Expectations for the Timely Dispositioning of Actions in the 'Open Item Tracking System'"
- QCR 97-120, "OE Evaluations Are Not Always Completed Within the Prescribed Time"

b. Observations and Findings

Over the past year, the NRC and licensee have identified inadequacies in the plant CR system. The NRC documented improvements in the CR system in Inspection Report (IR) 50-266/96009(DRP); 50-301/96009(DRP). QA personnel noted in A-P-97-06 that the OE group had improved since last year and that the necessary components and elements were being put in place for the corrective action program. This audit also concluded that more progress was needed to correct the previously identified, significant issue of untimeliness of OE reviews and CR processing. Inadequate staff resources was identified as one of the main contributors to current problems with these programs.

The inspectors discussed the corrective action and OE programs with QA supervision. The inspectors noted that management planned to increase the number of personnel in the OE/corrective action group and augment the group with personnel on temporary assignment from other groups. The inspectors also noted that most of the corrective action program procedures were in the revision process. All of these initiatives, in addition to those noted in the previous inspection report, represented significant improvement in the corrective action program.

The inspectors also noted improvements in the corrective actions of the CRs reviewed. However, the inspectors were concerned with inadequacies in the CR tracking system and the lack of timeliness in processing CRs and performing Root Cause Evaluations (RCEs), OE reviews, and corrective actions for CRs. The inspectors noted that many Significant Condition Adverse to Quality CR action items were open greater than 180 days. This lack of timeliness was a major contributing factor to the violation cited in Section O8.1.

In response to observations gathered during a recent radiation protection inspection (IR 50-266/97018(DRS); 50-301/97018(DRS)), the inspectors conducted several interviews with personnel from various departments to assess worker willingness to initiate CRs. The inspectors asked the workers three basic questions: (1) whether or not they had ever written a CR, (2) if they ever received feedback from anyone once they had written a CR regarding how the matter was dispositioned, and (3) if they had any ideas on how the system could be improved. Overall, the inspectors determined that site personnel generally initiated CRs when problems were identified. However, some groups in the various departments did not use the CR system. Personnel interviewed were generally satisfied with the feedback mechanism for generated CRs even though such a mechanism was not procedurally required.

c. Conclusions

The inspectors concluded that substantial improvements have been made to the corrective action system. However, significant challenges remain with inadequacies of the CR tracking system and timeliness of evaluation and completion of corrective actions. Also, the inspectors were concerned that some groups in the various departments still rarely used to CR system to identify problems.

O8 Miscellaneous Operations Issues

O8.1 Management of Commitments to the NRC

a. Inspection Scope (71707)

During the inspection period, the inspectors noted that several commitments to the NRC were missed or had to be extended including failure to submit a Licensee Event Report (LER) within 30 days after notifying the NRC via 10 CFR 50.72. The inspectors reviewed the following documentation:

- Quality Assurance (QA) Program Surveillance Report Number S-P-97-15, "NRC Open Items List"
- Licensee Event Report (LER) 266/97-035, "Reactor Coolant Pump Rotor Stand Support Not Seismically Adequate"
- Nuclear Power Business Unit Procedure (NP) 5.3.1, Revision 5, "CR System"
- NP 5.4.1, Revision 1, "Open Item Tracking Systems"
- Condition Report (CR) 97-2302, "NRC Commitment Item Not Met"
- CR 97-2320, "Failure to Submit LER on Reportable Event"
- QA Condition Report (QCR) 97-152, "No Due Date Assigned to LER Action Item"
- QCR 97-183, "Potential for Commitment Due Dates to be Missed"
- QCR 97-200, "Commitment Date for Corrective Action Missed"

b. Observations and Findings

QA personnel documented in S-P-97-15 that the overall process was not completely effective for inputting and tracking NRC open items and tracking corrective actions to these items and ensuring timely completion of the corrective actions. This surveillance determined that the program lacked certain guidance necessary to ensure that all NRC commitments were properly inputted into the tracking system, tracked to closure, and completed in a timely manner. This surveillance noted that NP 5.4.1 did not contain sufficient guidance to ensure commitments were always identified and flagged in the tracking system so they could be acted on in a timely manner. This surveillance also noted that NP 5.4.1 did not provide timeliness expectations for verification of documentation for close-out of NRC open items. These issues were documented in the QCRs listed above.

Finally, in a CR dated September 4, 1997, QA personnel documented the identification in August that one of the corrective actions for a previous violation (IR 50-266/96019(DRP); 50-301/96019(DRP)) of IST requirements for a safety injection valve (1SI-852A) had not yet been promptly completed. In a letter (dated March 31, 1997) submitted in response to the previous violation, the licensee stated that procedures for the testing the valve and three other similar valves (1SI-852B, 2SI-852A, and 2SI-852B) would be revised by May 17, 1997, to prevent recurrence of the violation. The failure as of August 1997 to promptly correct a condition adverse to quality, by revising the procedures, is an example of a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" (VIO 50-266/97016-01a(DRP); 50-301/97016-01a(DRP)).

The inspectors discussed inadequacies of meeting and tracking NRC commitments with several licensee managers and subsequently identified on July 8, 1997, that operations department staff had not promptly corrected a previous violation (IR 50-266/97006(DRP); 50-301/97006(DRP)) by failing to update the control room document (the Operations Notebook) on the requirements for initiating temporary changes to operations procedures. In a letter (dated June 23, 1997) submitted in response to the previous violation, the licensee stated that the document would be updated by June 30, 1997. The failure as of July 8, 1997, to promptly correct a condition adverse to quality, by updating the Operations Notebook, is an example of a violation 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" (VIO 50-266/97016-01b(DRP); 50-301/97016-01b(DRP)).

The inspectors also noted that CR 97-2302 documented the failure as of July 28, 1997, by maintenance personnel to promptly correct a violation involving the need to update reactor coolant pump procedures to include appropriate tagging information and other information. Originally, the need to update the procedures was cited as a violation in IR 50-266/96012(DRP); 50-301/96012(DRP), and in a letter (dated January 30, 1997) submitted in response to the violation, the licensee stated that the procedures would be updated by May 9, 1997. The failure to promptly correct a condition adverse to quality, by updating the procedures, is an example of a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" (VIO 50-266/97016-01c(DRP); 50-301/97016-01c(DRP)).

In IR 50-266/96018(DRS); 50-301/96018(DRS), the NRC cited the licensee for failure to submit an LER within 30 days for a condition prohibited by TSs as required by 10 CFR 50.73(a)(2)(I)(B). The response to this violation documented that NP 5.3.1 would be revised by June 1, 1997, to ensure that LERs were submitted as required. Although NP 5.3.1 was revised by the end of May 1997, the licensee identified on July 29, 1997, in CR 97-2320, that the licensee again failed to submit an LER within 30 days for an issue identified and reported to the NRC via four-hour report per 10 CFR 50.72(b)(2)(I) and 50.72(b)(2)(iii)(B) on May 16, 1997. The issue was subsequently documented in LER 266/97-035 submitted on August 15, 1997, and involved the failure of the Unit 1 reactor coolant pump rotor stand to meet design criteria if subjected to safe shutdown earthquake lateral loads. The failure to promptly correct a condition adverse to quality, by submitting the required LER, is an example of a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" (VIO 50-266/97016-01d(DRP); 50-301/97016-01d(DRP)).

c. Conclusions

The inspectors concluded that significant deficiencies existed in the licensee's tracking of NRC commitments. These resulted in missed or delayed responses or corrective actions for NRC issues. A violation with four examples for failure to assure prompt corrective actions was identified.

O8.2 (Closed) Unresolved Item (URI) 50-301/96004-01: Reactor Trip Due to Spurious Closure of Turbine Stop Valves.

On May 18, 1996, the Unit 2 reactor tripped due to a turbine trip. The licensee's investigation into the cause of the trip was adequate, but was unable to identify the exact cause of both stop valves closing. According to the turbine system engineer, a spurious actuation of the electro-hydraulic control emergency trip solenoid valve, 20 ET, was likely the cause. The valve was replaced and the old valve was examined but no mechanical problems were found.

The licensee's trip classification scheme was described in OM 4.1.1, "Post-Trip Review." Initially, the inspectors had a concern that the procedural classification of the trip was inappropriate. After further review and discussion with the SRO who classified the trip and the turbine system engineer, the inspectors concluded that procedural requirements were met, but the SRO's classification was not conservative. Based on review of recent changes by station management, the inspectors concluded that this type of nonconservative classification would not recur given a similar trip.

O8.3 (Closed) LER 301/96-001: Reactor Trip Due to Spurious Closure of Turbine Stop Valves.

This issue was discussed above in Section O8.2. Additionally, licensee personnel performed electrical testing for the control and power circuitry for the 20 ET valve during the recent Unit 2 outage. No unusual conditions were identified during this testing. Inputs were added to the primary plant computer system which will allow indication of any future problems with the 20 ET valve. The inspectors have no additional concerns with this event or subsequent corrective actions.

O8.4 (Closed) LER 266/97-034; 301/97-034: Unplanned Loss of Voltage on Train "B" Safeguards Buses.

On July 7, 1997, during the performance of loss of power testing for the emergency diesel generators (EDGs), the output breakers tripped open on the G03 EDG while it was supplying power to the Train "B" 4160 and 480-V safeguards buses for both Units. This event was discussed in IR 50-266/97013(DRP); 50-301/97013(DRP), Section 02.1.

The root cause of the output breaker trip was a mis-wiring of the "Loss of Field" relay due to inadequate design and design review during installation. The problem was effectively corrected for the two Train "B" EDGs and both EDGs have been returned to service.

Additionally, licensee personnel performed RCE 97-039, "'B' Train Vital Bus De-energization" for this event.

The inspectors reviewed the corrective actions from RCE 97-039 and the rewiring of the "Loss of Field" relay and had no further concerns with this issue.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

NRC Inspection Procedures 62707 and 61726 were used in the inspection of plant maintenance and surveillance activities. The inspectors observed and reviewed selected portions of the following maintenance and test activities:

- Work Order Plan 9707908, "Component Cooling Water Pump Repairs Unit 2"
- Routine Maintenance Procedure 9008-1, Revision 15, "Residual Heat Removal Pump Removal and Installation"
- Technical Specification Test 9, Revision 18, "Control Room Heating and Ventilation System Monthly Checks"
- Inservice Test [IT] 06, Revision 40, "Containment Spray Pump and Valve Test (Quarterly) Unit 2"
- IT 04, Revision 35, "Low Head Safety Injection Pumps and Valves (Quarterly) Unit 2"
- IT 05, Revision 34, "Containment Spray Pumps and Valves (Quarterly) Unit 1"
- IT 09A, Revision 16, "Cold Start Testing of Turbine-Driven Auxiliary Feedwater (AFW) Pump and Valve Test (Quarterly) Unit 2"
- IT 22, Revision 5, "Charging Pumps and Valves (Quarterly) Unit 2"
- IT 295B, Revision 8, Overspeed Test Turbine-Driven AFW Pump, Refueling Interval, Unit 2"

The work performed under these activities was professional and thorough. Technicians were experienced and knowledgeable of their assigned tasks. The work packages were present at the job sites and actively used by the technicians for all work observed. System engineers were frequently observed monitoring job progress.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Material Condition of Control Room Instrumentation and Controls (62707)

Several self-revealing material condition issues complicated control room operations during this inspection period. In one instance, a control rod moved one step in the outward direction unexpectedly. The licensee identified that the keying of a radio near the rod control system instrumentation was the apparent cause of the rod movement. Operators informed the inspectors that this had occurred in the past. In another instance, repeated alarms for "High Flux at Shutdown" at the control room annunciator (1CO41A1-3) were received. These alarms were caused by spiking on Unit 1 source range detector (1N-31), which appeared to result from electrical or magnetic interference.

Operator response to each of the materiel condition problems was prompt and appropriate. Operators exhibited good intolerance for these issues and initiated CRs to document each concern. The licensee directed that the unanticipated control rod movement and the spurious 1N-31 spiking be evaluated for root causes. These actions appeared to be appropriate to the inspectors. The inspectors had no additional concerns with these issues.

M2.2 Technical Specification Violations Due to RHR Loop Inoperability

a. Inspection Scope (62707 & 37551)

On two separate occasions during the inspection period, TS 15.3.1.A.3.b was violated due to equipment failures on Unit 2. The inspectors reviewed the following documentation for these events:

- TS 15.3.1, "Reactor Coolant System"
- Final Safety Analysis Report (FSAR) Section 9.3, "Auxiliary Coolant System"
- Piping and Instrument Drawing, Auxiliary Coolant System, Unit 2, 110E029, Sheet 1, Revision 40
- CR 97-2310, "Component Cooling Water (CCW) Leak on Unit 2 RHR Heat Exchanger Outlet"
- CR 97-2351, "RHR Pump Seal Leakage"
- CR 97-2388, "RHR Pump Seal Leakage Increase"
- CR 97-2629, "RHR Pump Has a Seal Leak"

b. Observations and Findings

Technical Specification 15.3.1.A.3.b required both RHR loops to be operable when the reactor coolant temperature is less than 140 degree Fahrenheit (°F). This TS allowed one RHR loop to be out-of-service when the vessel head was removed and the refueling cavity flooded or to meet surveillance requirements. During both of these events, Unit 2 reactor coolant was below 140°F with the reactor vessel head installed and tensioned.

<u>RHR Loop Inoperable Due to Component Cooling Water (CCW) Leakage</u>

On July 29, 1997, Unit 2 COs noted CCW surge tank level decreasing. Subsequently, a leak was identified on the CCW piping to the Unit 2 "B" RHR heat exchanger (2HX-11B). Operations personnel isolated the leak and declared the associated RHR loop inoperable. This decision placed Unit 2 in a configuration that violated TS 15.3.1.A.3.b. The leak was due to a partial circumferential crack in a section of one-inch piping for the outlet of the heat exchanger shell side relief valve (2CC-736B). This same event occurred in October 1996 and was documented in IRs 50-266/96012(DRP); 50-301/96012(DRP) and 50-266/96015(DRP); 50-301/96015(DRP).

The piping was repaired and the "B" RHR loop was declared operable on July 31, 1997. The removed piping section was sent to an off-site lab for further analysis of the failure mechanism. The licensee scheduled to perform Root Cause Evaluation 97-053, "CCW Leak at "B" Heat Exchanger Inlet Pipe Joint" for this event.

The inspectors discussed this issue with plant engineers and reviewed repair records. Although the inspectors had no concerns with the repair of the CCW piping, the inspectors were concerned that corrective actions from the October 1996 event did not prevent this current event. Plant engineers informed the inspectors that a more thorough stress analysis of the CCW piping after the first event probably would have identified this additional piping failure point and prevented this event.

<u>RHR Loop Inoperable Due to RHR Pump Seal Leakage</u>

On August 3, 1997, the Unit 2 CO noticed a slight, steady lowering of the vessel level over a 16-hour period. Subsequently, plant personnel identified abnormal mechanical seal leakage from the Unit 2 "A" RHR pump (2P-10A). At 9:50 a.m. on August 6, 1997, 2P-10A was declared inoperable because of the excessive seal leakage.

At 3:57 p.m. on August 6, 1997, operators had increased reactor coolant temperature to above 140°F. This placed Unit 2 out of TS 15.3.1.A.3.b and into compliance with TS 15.3.1.A.3.a. Technical Specification 15.3.1.A.3.a required at least two of four decay heat removal methods operable when the reactor coolant temperature was less than 350°F and greater than 140°F. These methods included the "A" or "B" reactor coolant loops with associated steam generators and reactor coolant pumps or "A" or "B" RHR loops.

On August 10, 1997, all repairs and post-maintenance testing for 2P-10A were completed and the pump was declared operable. The licensee scheduled to perform Root Cause Evaluation 97-058, "RHR Seal Leakage" for this event. The inspectors reviewed the repair and testing data and observed portions of the work and had no technical concerns with the immediate corrective actions.

The failure to have both RHR loops operable for Unit 2 when the reactor coolant temperature was less than 140°F and the reactor vessel head was installed is a violation of TS 15.3.1.A.3.a (VIO 50-301/97016-02(DRP)).

Late in the inspection period, the licensee was forced to defer vendor recommended oil changes on the Unit 1 CCW pumps due to TS 15.3.1.A.3.a. Unit 1 reactor coolant temperature remained below 140°F and the reactor vessel head was installed throughout the inspection period.

The inspectors noted that Improved Standard TSs contained limiting conditions for operation action statements that would prevent a TS violation for the conditions described above. The inspectors were concerned that TS 15.3.1.A.3.a did not contain these provisions. This results in a TS violation anytime the RHR system was inoperable with the reactor coolant temperature less than 140°F and the reactor vessel head was installed.

c. Conclusions

Corrective actions from the October 1996 CCW pipe crack were not comprehensive enough to prevent the July 1997 failure. In addition, the inspectors were concerned that when the reactor coolant temperature is than 140°F and the reactor head is installed, a TS violation occurs anytime an RHR loop is inoperable with the current TSs. Two example of a violation of the minimum RHR loop operability requirements was identified.

M3 Maintenance Procedures and Documentation

M3.1 Unit 2 SG Replacement Procedural Update Review

a. Inspection Scope (71707 & 61726)

The inspectors reviewed the changes made to the licensee's procedures due to replacement of the Unit 2 SGs. In addition to the Instrument and Control (I&C) procedures, the following documents were used:

- TS 15.2.0, "Limiting Limits and Limiting Safety System Settings"
- TS 15.3.1, "Reactor Coolant System"
- TS 15.3.4, "Steam and Power Conversion"
- TS 15.3.5, "Instrumentation System"
- TS 15.4.1, "Operational Safety Review"
- FSAR Section 10, "Steam and Power Conversion System"
- FSAR Section 14, "Safety Analysis"
- Safety Evaluation Report (SER) 96-084-02, "Point Beach Nuclear Plant Unit 2 SG Design," December 20, 1996
- SER 96-114, "Unit 2 SG Replacement - Reactor Protection, Alarm, and Control Setpoint and Procedure Changes," October 10, 1996

- SER 97-008, "Water Level Instrumentation Changes, SG Replacement," January 23, 1997

- Point Beach Nuclear Plant Calculation # PNPB-1C-26, Revision 1, "SG Narrow Range Water Level Scaling Calculation"

- CR 97-2037, "Update to Tank Level Book"

- CR 97-2188, "Inaccurate SG Level Values in Shutdown Emergency Procedure [SEP] 3.0"

b. Observations and Findings

The licensee changed many I&C and operations procedures to calibrate instruments that had setpoint changes due to the new Unit 2 SGs. These setpoint changes were documented in SERs 96-084-02, 96-114, and 97-008 and Calculation # PNPB-1C-26. These setpoint changes required recalibration of all of the trip and control signals that were based on the narrow range water level instruments. These setpoint changes were used for TS Change Requests 188 and 189, which were approved by the NRC on July 1, 1997. Operations management documented in CR 97-2037 that the tank level book had not been updated to reflect the Unit 2 SGs. The cognizant SG system engineer documented in CR 97-2188 that SEP 3.0 had not been updated with the latest information from the new SGs.

The inspectors verified that the information contained in the changes to the I&C procedures agreed with the information contained in SERs 96-084-02, 96-114, and 97-008 and Calculation # PNPB-1C-26. The inspectors also verified that the tank level book, SEP 3.0, and a random sampling of operations procedures were updated to reflect the new SG information. The inspectors noted that all procedures reviewed had been properly updated with the new SG setpoint information and no discrepancies were found between the procedures and the setpoint documented basis information.

c. Conclusions

The inspectors concluded that required I&C and operations procedure changes were made prior to declaring the Unit 2 SGs operable.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Inspection Followup Item (IFI) 50-266/96018-09; 50-301/96018-09: Adequacy of EDG Air Start Motor Sequencing.

On December 3, 1996, the NRC identified concerns during the performance of a G04 EDG monthly test as to whether or not the north air start banks actuated during the surveillance test. The licensee was unable to verify that the motors had started.

In response to this concern, the licensee revised the test procedures for the G03 and G04 EDGs to include monitoring and verification of the air start motors for proper starting sequence and operation. The inspectors verified that the north air start banks did actuate during the subsequent monthly surveillance test. The inspectors have no additional concerns with this issue or the corrective actions implemented.

M8.2 (Closed) IFI 50-266/95004-02; 50-301/95004-02: P-35 B Diesel Fire Pump Failure to Start.

On March 30, 1995, the diesel fire pump, P-35 B, failed to start when safety-related bus 1A06 deenergized during EDG G03 tie-in testing. This problem occurred following a January 1995 overhaul of the diesel fire pump engine. Operators tried several times to start the diesel pump without success. The diesel pump was finally restarted after some leaking injection tubing fittings were tightened. The inspectors were concerned with the reliability of the pump due to this start failure.

The inspectors reviewed the routine surveillance test data for the diesel fire pump over the last two years and discussed this issue with cognizant engineering personnel. Discussions and test data review indicated that the pump has been very reliable and had no start problems since this problem occurred. The inspectors have no further concerns with this issue.

M8.3 (Closed) LER 301/97-004: RHR Loop Inoperable Due to CCW Leakage.

This item was discussed in Section M2.3 and is closed.

M8.4 (Closed) LER 301/97-005: RHR Loop Inoperable Due to RHR Seal Leakage.

This item was discussed in Section M2.3 and is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Engineering Response to Design Basis and Licensing Basis Issues

a. Inspection Scope (37551)

The inspectors monitored the involvement of the engineering staff in identifying and assessing potential non-conformances with the plant design and licensing basis.

b. Observations and Findings

Licensee engineering staff identified several potential non-conformances with the design and licensing basis during this inspection period. One issue involved the potential for a common mode failure mechanism which could defeat the low pressure suction trip protective feature for more than one AFW pump. A second issue dealt with the potential for a degraded voltage load shed on the "A" train safety-related 480-V electrical distribution buses if the containment spray pump were to start concurrently with the third service water pump while the bus was being supplied by an EDG. A third issue dealt with removal of a CCW pump from service for a required oil change when two trains of the RHR system, a system supported by CCW, were required by TSs to be operable (Section M2.2).

The inspectors observed that the engineering staff performed well in identifying each of the issues, in assessing the design and licensing basis relative to each issue, and in recommending conservative courses of action. The inspectors observed that plant management reached conservative conclusions with respect to each issue after self critical, self-challenging, open, and frank discussion of the options available. A Unit 1 restart restraint was identified because of the AFW issue. Unit 2 was shutdown for an unscheduled outage to correct the degraded voltage load shed issue. A draft change to the TSs or change of Unit 1 plant conditions was considered to address the need to perform preventive maintenance on the Unit 1 CCW pump issue. The oil was not changed until redundant RHR trains were no longer required.

c. Conclusion

The licensee engineering organization performed well in identifying and assessing technical concerns during the reporting period. Plant management took appropriate, conservative actions, including shutting down Unit 2, to address each identified concern after self-critical and self-challenging discussion of available options.

E2 Engineering Support of Facilities and Equipment

E2.1 Water Hammer in the Unit 2 AFW System

a. Inspection Scope (37551 & 71707)

The licensee heard possible water hammer noise in the AFW system. The inspectors walked down the safety-related AFW system and evaluated the licensee's response to the issue.

b. Observations and Findings

On August 25, 1997, the licensee staff heard water hammer noise at the AFW discharge pipe to the Unit 2 feedwater system and SGs. The inspectors performed independent assessments of the origin and nature of the noise and observed system engineers perform diagnostic evaluation using acoustic and vibrational monitoring equipment.

The inspectors felt and heard irregular vibration in the AFW discharge piping in the Unit 2 turbine-driven AFW pump (2P-29) equipment space. Similar, but less pronounced, vibration was evident near the motor-driven AFW pumps (P-38A and P-38B). The AFW supply piping to the Unit 2 SGs was observed to be vibrating with an approximately 1/8" deflection in the Primary Auxiliary Building (PAB). No indications of backflow through the system were observed. The system engineer indicated to the inspectors that the probable cause of the indications was void collapse in the AFW piping near the point where it connected to the main feedwater system. The licensee considered the AFW system operable pending identification and correction of the cause of the pipe vibrations. The inspectors considered this evaluation to be acceptable.

On September 6, 1997, system engineers used thermal imaging equipment to identify slight leakage in the Unit 2 SG "first-off" AFW check valve (2AF-100) which isolated the AFW piping from the Unit 2 "A" SG mainfeed line. This leakage was believed to be causing void formation, and collapse, on the upstream side of 2AF-100. The licensee was reviewing potential corrective actions at the end of the inspection period. The inspectors requested copies of the licensee documentation on AFW pipe supports and cyclic fatigue analysis for use in evaluating the licensee's corrective action determinations. This issue is considered to be an IFI (50-301/97016-03(DRP)) pending inspector review of the licensee's corrective actions.

c. Conclusions

System engineers used all available technical means to identify the source of water hammer indications in the AFW system. Corrective actions were being evaluated by the licensee at the end of the inspection period. The inspectors did not identify any concerns to date with the licensee's response to the issue.

E3 Engineering Procedures and Documentation

E3.1 Failure to Include Acceptance Criteria in Surveillance Procedures

a. Inspection Scope (61726, 62707 & 37551)

The inspectors reviewed two circumstances involving the failure to include test acceptance criteria in surveillance procedures. The first instance involved the documentation associated with performance of a TS surveillance of the 125-volts direct current (VDC) Station Battery (D-06). The second involved the control of acceptance criteria for inservice testing (IST) results of pumps and valves that are included in the IST program.

b. Observations and Findings

TS Surveillance of the 125 VDC Station Battery (D-06)

On the morning of September 4, 1997, the inspectors noted a DSS log entry which stated that five cells in the safety-related D-06 station battery had been found with specific gravity out-of-tolerance (low) and that an operability determination was being performed. The inspectors inquired about the operability status of D-06 to one of the on-shift operations department supervisors. The supervisor informed the inspectors that D-06 was considered operable pending completion of the operability determination because problems with out-of-tolerance specific gravity had been found in the past, but the determinations had always been that the effected battery was operable.

Late on September 4, 1997, the inspectors asked the operations department and site engineering managers why out-of-tolerance surveillance results, such as those documented for D-06, did not result in immediate declarations of inoperability for safety-related components. Guidance contained in NRC Generic Letter 91-18, "Inspection Manual Guidance 9900 on Degraded/Nonconforming Conditions and on Operability," indicates that components which do not satisfy test requirements should be considered inoperable until a technical evaluation demonstrates that new test requirements can be established or until the component is repaired. TS 15.4.0.1 specifies that components that do not satisfy TS surveillance requirements are inoperable. The managers stated that they would look into the status of the battery surveillance.

On September 5, 1997, the licensee initiated two condition reports (CRs) dealing with D-06. The first CR documented that five cells had as found specific gravity readings which were outside of the proceduralized "minimum" values, and that an operability determination was required within 72 hours. The second CR documented that engineering department staff had not been informed of the out-of-tolerance specific gravity results, obtained on September 3, 1997, until September 5, 1997. An operability determination was subsequently performed within 72 hours of the out-of-tolerance readings that concluded D-06 was operable.

The inspectors reviewed RMP 9046-1, "Station Battery," Revision 22. RMP 9046-1 provided for the completion of TS surveillance requirements 15.4.6.B.1, 15.4.6.B.2, and 15.4.6.B.3, which, in part, included obtaining monthly cell voltage readings and quarterly specific gravity readings for evaluation of abuse or deterioration. RMP 9046-1 satisfied the literal requirements of the TS surveillance. However, while RMP 9046-1 contained "minimum" values for cell voltage and specific gravity, consistent with the battery vendor manuals, these were identified as action levels rather than acceptance criteria. RMP 9046-1 did not include acceptance criteria, such as a limiting cell voltage or specific gravity, or a limiting change in cell voltage or specific gravity between consecutive readings, by which the ability of the battery to perform its safety function in service could be promptly evaluated.

10 CFR Part 50, Appendix B, Criterion XI, "Test Control," requires, in part, that test procedures include acceptance criteria (limits) from design documents. The failure to include acceptance criteria in RMP 9046-1 was an example of a violation (VIO 50-266/97016-04a; 50-301/97016-04a) of Criterion XI. The inspectors were concerned that the failure to include design limit acceptance criteria in a TS required surveillance procedure could lead to delays in recognizing and addressing inoperable safety-related components.

Control of Acceptance Criteria for IST Results

The inspectors observed the performance of IT 09A for the Unit 2 turbine-driven AFW pump 2P-29. Conduct of the surveillance was good and operators used good communications; however, a couple of weaknesses were identified. An operator stopwatch error during valve stroke time testing on 2 of 14 occasions resulted in repeating valve stroke time measurements on two valves. This is a concern due to possible preconditioning of the valves. Also, the inspectors noted that the procedure did not contain the acceptance criteria for the valve and pump parameters being tested, rather, the operators were referred to the "IST Pump and Valve Acceptance Criteria Binder." When operators completed collecting pump operating data for 2P-29 while it was in a recirculating flow condition, they referred to the Acceptance Criteria Binder and identified that the acceptance criterion for pump differential pressure was not met. The DSS, who considered the results unsatisfactory, re-instituted required fire rounds, and contacted engineering for evaluation. The inspectors reviewed the procedure and the Acceptance Criteria Binder and determined that the operators were referring to acceptance criteria for different operating conditions. The pump differential pressure acceptance criterion was actually evaluated at a full flow condition of 400 gallons per minute. This part of the procedure had not been performed yet. The inspectors informed the operators of this and when the pump was tested at full flow conditions, the acceptance criterion was satisfied.

During a review of the surveillance tests for the Unit 2 charging pumps (2P-2A, B, & C) the inspectors noted that acceptance criteria were not contained in the IT procedure. The acceptance criteria was located in the "IST Pump and Valve Acceptance Criteria Binder" a separate document maintained in the control room and other locations in the plant. The inspectors noted that the vibration acceptance criteria was entered as a "pen and ink" change" initialed and dated by the IST engineer. The results of the test were determined to be satisfactory based on the handwritten information in the acceptance criteria binder.

The inspectors discussed the level of control and supervisory oversight employed to ensure that the handwritten changes were appropriate. Based on interviews with the IST engineer and engineering department supervision, the inspectors learned that the IST engineer is one of only two people authorized to make changes to the acceptance criteria binder. However, the changes handwritten in the binder do not routinely receive any supervisory review prior to being used as acceptance criteria. The inspectors discussed the adequacy of the level of control applied to the information placed in the acceptance criteria binder. Although the IT procedures receive a full Manager's Supervisory Staff review for changes, the basis parameters used to declare acceptable performance of the tested pumps and valves were contained in a separate document which did not receive such management review. The failure to include acceptance criteria within the inservice test procedures was considered a violation of the 10 CFR 50, Appendix B, Criterion XI, "Test Control," (VIO 50-266/97016-04b(DRP); 50-301/97016-04b(DRP)).

c. <u>Conclusions</u>

The inspectors identified that the procedures for TS related and Inservice testing surveillance test procedures did not specify limits for test criteria. Two examples of a violation of NRC requirements were identified. One involving D-06 and the proper reference parameters for operability determinations and another involving the adequate control of acceptance criteria for pumps and valves in the IST program. Although two examples of a violation were identified, this is a programmatic concern that must be addressed broadly.

E3.2 <u>Programmatic Review of 10 CFR 50.59 Safety Evaluations</u>

a. <u>Inspection Scope (37551)</u>

The inspectors reviewed the changes made to the licensee's 10 CFR 50.59 safety evaluation program. The inspectors also reviewed several safety evaluation reports (SERs). Some of the documents used included:

- NP 10.3.1, Revision 6, "Authorization of Changes, Tests, and Experiments (10 CFR 50.59 and 72.48 Reviews)"
- CR 97-2688, "Training for 50.59/72.48 Screenings and Evaluations Did Not Appear to be Complete and/or Consistent"

b. Observations and Findings

About a year ago, the NRC started identifying several inadequacies with the licensee's SERs and SER program. The NRC identified several SER screenings that should have had full SERs. Also, several SERs did not have sufficient basis information to support the conclusion that a TS change was not required or that an unreviewed safety question (USQ) did not exist. The inspectors had previously noted that NP 10.3.1 did not contain clear guidance to determine the answers to these two questions. Two notable examples of SERs that incorrectly concluded that a TS change was not required or that a USQ did not exist were the number of service water pumps required during a loss of coolant accident and manual operator action for motor-driven AFW pumps during an accident.

Licensee personnel issued a complete rewrite of NP 10.3.1 in May 1997. Subsequently, personnel from every department were trained in the changes to the NP 10.3.1 procedure. The inspectors noted that NP 10.3.1 provided a much clearer definition of what constituted a USQ or TS change and better expectations for SERs and SER screenings preparation and review. The inspectors also noted improved basis information for conclusions reached in some of the SERs and SER screenings reviewed. However, the inspectors identified numerous instances of weak SERs and SER screenings for plant modifications and plant procedures, and procedure and setpoint changes that did not have SERs or SER screenings performed. The inspectors noted that these examples showed the lack of consistency that still existed in performing and supporting conclusions reached in the SERs and SER screenings. The inspectors were also concerned with 10 CFR 50.59/72.48 SER and SER screening training that was incomplete or inconsistent as documented in CR 97-2688.

c. Conclusions

The inspectors concluded that SERs and screenings for SERS have improved overall with improved basis information to support conclusions in many instances. Also, changes to NP 10.3.1 have resulted in much improved guidance in writing SERs. However, inconsistencies were noted by the inspectors between SER quality and rigor of the basis information for determining that no USQ existed or that a TS change was not required.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) VIO 50-266/96002-04; 50-301/96002-04: Spent Fuel Pool Heat Exchangers Testing Inadequacies.

The NRC identified that the licensee had failed to effectively correct a condition adverse to quality related to the testing of the spent fuel pool heat exchangers. The testing was specified in accordance with commitments to NRC Generic Letter 89-13, "Service Water Problems Affecting Safety-Related Equipment." Root causes for the testing problems included insufficient temperature differences between the heat exchanger shell and tube side water to obtain accurate heat transfer data, lack of instrumentation on the heat exchanger inlet, and a lack of continuity regarding assignment of a responsible system engineer for the system.

The licensee's corrective actions for these problems included the following:

- a total re-write of the test procedure,
- performing the test at temperatures closer to design values providing for better heat transfer data,
- the installation of a thermometer to the inlet of the heat exchanger for more accurate temperature indications, and
- recently improved system engineer assignments with roles and responsibilities provided by engineering management.

The inspectors reviewed the revised test procedures and discussed this issue with cognizant engineers. The inspectors verified that the corrective actions were completed and have prevented recurrence of these deficiencies regarding the spent fuel pool heat exchanger system testing. The inspectors have no additional concerns with this issue.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Comments

NRC Inspection Procedure 71750 was used in the performance of an inspection of the plant support area.

Radiological housekeeping was adequate during the inspection period. During walkdowns of the facility, the inspectors noted items such as scaffolding and tools removed from the Unit 2 containment that were temporarily stacked in the Primary Auxiliary Building (PAB) Unit 2 fan room. Also, the inspectors observed personal contamination clothing and equipment scattered outside of the spent fuel pool area during work to reclaim spaces in the pool. Although the items around the spent fuel pool did not violate foreign material exclusion controls, they cluttered the work area and were examples of poor housekeeping. The inspectors informed health physics (HP) management of these conditions and the areas were cleaned up.

R1.2 Uncontrolled Contamination on RHR Heat Exchanger Outlet Cross Connect Valves

a. Inspection Scope (71750)

The inspectors noted boric acid crystal buildup on the Unit 2 RHR heat exchanger outlet cross-connect valves while performing a routine walkdown of the PAB. The affected areas of the valves and piping were later found to be contaminated.

b. Observations and Findings

During a routine walkdown of the PAB, the inspectors noted boric acid crystal buildup from packing leaks on the Unit 2 RHR heat exchanger outlet cross connect valves (2RH 716 A/B/C/D) and surrounding piping. No contamination control postings were observed in the area of the valves. Suspecting the boric acid to be contaminated, the inspectors notified HP personnel who surveyed it.

The survey results indicated contamination existed on the valves with levels as high as 984 disintegrations per minute (dpm)/100 centimeters-squared (cm^2). Technicians subsequently posted the area with contaminated area tape in accordance with station HP procedures, which define a contaminated area as one having contamination levels of 300 dpm/100 cm^2 or greater. This failure to perform an adequate survey is a violation of 10 CFR 20.1501. However, it is of minor significance and is being treated as a Non-Cited Violation (NCV), consistent with Section IV of the NRC Enforcement Policy (NCV 50-301/971016-05(DRP)).

Even though the safety significance of the contamination levels was minimal, the inspectors raised this issue with station management as an example of the lack of awareness of equipment conditions by HP technicians and AOs during tours of the PAB. The boric acid noted on the valves appeared to have been there for several days providing ample opportunity for identification by the AOs or HP technicians.

c. Conclusions

The inspectors concluded that the contamination discovered on the RHR heat exchanger outlet cross connect valves was of minor safety significance; however, ample opportunity to identify the contamination existed for HP technicians or AOs in the plant. This brought into question the sensitivity and thoroughness of HP technicians and AOs while performing duties and rounds within the PAB.

R1.3 High Radiation Area Door Found Unlocked (71750)

The inspectors reviewed the circumstances surrounding the discovery that the Unit 2 lower containment equipment access door was unlocked. At the time of the discovery, the containment was posted as a required locked, high radiation area, and high radiation area postings inside of containment had been removed. An AO discovered the unlocked door on August 13, 1997, and reported the condition to the HP personnel. The door was subsequently locked as required.

Licensee personnel verified that no one entered the containment while it was unlocked since no alarms were received in the control room for the hatch doors being opened and no unusual dosimetry readings were noted. The Unit 2 reactor was not critical during this incident. As a followup to this event, the licensee initiated Root Cause Evaluation 97-061, "High Radiation Barrier Violation," to review the incident.

The failure to maintained locked a high radiation area is a violation of TS 15.6.11 (VIO 50-301/97016-06(DRP)). The high radiation control problem illustrated by this event is another example of recent high radiation area posting, entry, and control problems at the station (IRs 50-266/96009(DRP); 50-301/96009(DRP), 50-266/96016(DRS); 50-301/96016(DRS), and 50-266/97004(DRS); 50-301/97004(DRS)).

S1 Conduct of Security and Safeguards Activities

S1.1 Inadequately Compensated Perimeter Intrusion Detection Zone

a. Inspection Scope (71750)

The inspectors reviewed the circumstances surrounding a reportable security event which occurred on August 15, 1997.

b. Observations and Findings

On August 15, 1997, security personnel discovered that on two occasions adequate compensatory actions had not been taken for the loss of an intrusion alarm point. The failures occurred when a security multiplexer unit lost power at 3:22 a.m. during severe weather conditions. Adequate compensatory actions were not taken between 5:29 a.m. and 5:45 a.m. (16-minute duration) and between 6:37 a.m. and 7:30 a.m. (53-minute duration). When identified, security personnel immediately implemented appropriate compensatory measures and verified that no unauthorized or undetected access to the protected area had occurred. The licensee notified the NRC about this event on August 15, 1997, via a one-hour security violation report pursuant to 10 CFR 73.71(b)(1). Security personnel also documented this event in CR 97-2540.

The inspectors reviewed the documentation associated with this event and discussed the issue with security personnel. The inspectors noted that the security department had two other failed or degraded safeguards systems which have had inadequate compensatory measures during the past two years. These events were documented in IRs 50-266/97007(DRS); 50-301/97007(DRS) and 50-266/96017(DRS); 50-301/96017(DRS).

c. Conclusions

The inspectors were concerned with this additional failure of the security department to take required compensatory action for a failed or degraded safeguards system. The inspectors were also concerned with the failure of corrective actions from previous events to prevent this issue. The LER for this event will remain open awaiting further review by a regional security specialist.

F1 Control of Fire Protection Activities

F1.1 Fire Brigade Response to Smoke from a Unit 2 Main Feedwater Pump (71750)

The inspectors observed the response of the station fire brigade to smoke from the Unit 2 "B" main feedwater pump on September 4, 1997. The inspectors noted timely response to the scene by the brigade and good command and control by the on-scene fire chief. However, the inspectors observed that several plant personnel from various departments and management levels lingered in the response area and had to be asked to leave by the fire brigade members.

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 September 9, 1997. 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 (WEPCO)

A. J. Cayia, Plant Manager
R. G. Mende, Operations Manager
G. R. Sherwood, Maintenance Field Services Manager
S. A. Morrison, Maintenance Planning & Scheduling Manager
J. G. Schweitzer, Manager, Site Engineering
P. B. Tindall, Manager, Radiation Protection
J. E. McCullum, Security Supervisor
M. E. Reddemann, Quality Assurance Manager
F. P. Hennessey, Production Planning Manager
T. G. Malanowski, Senior Project Engineer, Licensing
W. J. Herrman, Nuclear Supply Services Manager
G. L. Boldt, Special Engineering Assistant to Site Vice President
N. L. Hoefert, Continuous Safety and Performance Assessment Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71711:	Plant Startup From Refueling
IP 71750:	Plant Support Activities

ITEMS OPENED AND CLOSED

<u>Opened</u>

50-266/97016-01	VIO	Four examples of a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective action"
50-301/97016-02	VIO	T/S violations due to RHR loop inoperability
50-301/97016-03	IFI	Water hammer in the Unit 2 AFW System
50-266/97016-04 50-301/97016-04	VIO	Failure to include acceptance criteria within inservice test and maintenance surveillance procedures
50-301/971016-05	NCV	Failure to perform adequate contamination surveys
50-301/97016-06	VIO	Failure to lock a high radiation area

<u>Closed</u>

50-301/96004-01	URI	Reactor trip due to spurious closure of turbine stop valves
50-301/96001	LER	Reactor trip due to spurious closure of turbine stop valves
50-266/97034 50-301/97034	LER	Unplanned loss of voltage on train "B" safeguards buses
50-266/96018-09 50-301/96018-09	IFI	Adequacy of EDG air start motor sequencing
50-266/95004-02 50-301/95004-02	IFI	P-35 B diesel fire pump failure to start
50-301/97004	LER	RHR loop inoperable due to CCW leakage
50-301/97005	LER	RHR loop inoperable due to RHR seal leakage
50-266/96002-04 50-301/96002-04	VIO	Spent fuel pool heat exchangers testing inadequacies

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
AO	Auxiliary Operator
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CO	Control Operator
CR	Condition Report
°F	Degrees Fahrenheit
dpm/cm^2	Disintegrations Per Minute Per Centimeter-Squared
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
DSS	Duty Shift Supervisor
EDG	Emergency Diesel Generator
FSAR	Final Safety Analysis Report
HP	Health Physics
I&C	Instrument and Control
IFI	Inspection Follow-up Item
IP	Inspection Procedure
IR	Inspection Report
IST	Inservice Testing
IT	Inservice Test
LCO	Limiting Condition for Operation
LER	Licensee Event Report
NCV	Non-Cited Violation
NP	Nuclear Power Business Unit Procedure
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OE	Operating Experience
OM	Operations Manual
OP	Operations Procedure
OSRC	Off-Site Review Committee
PAB	Primary Auxiliary Building
PDR	Public Document Room
QA	Quality Assurance
QCR	QA Condition Report
RCE	Root Cause Evaluation
RESP	Reactor Engineering Surveillance Procedure
RHR	Residual Heat Removal
RP&C	Radiological Protection and Chemistry
SEP	Shutdown Emergency Procedure
SER	Safety Evaluation Report
SG	Steam Generator
SRO	Senior Reactor Operator
TS	Technical Specification
URI	Unresolved Item
USQ	Unreviewed Safety Question
VDC	Volts-Direct Current
VIO	Violation
V	Volt
WEPCO	Wisconsin Electric Power Company