U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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License Nos.	DPR-24, DPR-27
Report No.	50-266/96019, 50-301/96019, 72-005/96019
Licensee:	Wisconsin Electric Power Company, WEPCo
Facility:	Point Beach Nuclear Plant, Units 1 & 2
Location:	6612 Nuclear Road Two Rivers, WI 54241-9516
Dates:	December 17, 1996 Through January 27, 1997
Inspectors:	A. McMurtray, Senior Resident Inspector C. Keller, Resident Inspector P. Louden, Resident Inspector M. Kunowski, Project Engineer
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EXECUTIVE SUMMARY

Point Beach Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-266/96019, 50-301/96019, 72-005/96019

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

Operations

- On December 16, 1996, the Unit 2 "A" (2A) residual heat removal (RHR) pump was operated for 38 minutes with its discharge valve shut and no recirculation flow path available (Section O4.2).

- On December 17, 1996, Unit 1 power was reduced from 100 percent to 90 percent. The reduction was well planned and executed (Section O4.1).

Maintenance

- During the January 1997 performance of TS-83, a high fuel oil pressure alarm was received after the emergency diesel generator (EDG) G-03 was accelerated to rated speed. No condition report (CR) was written documenting the alarm (Section M3.1).

- On January 16, 1997, the licensee discovered that the Unit 1 RHR/Low Head Core Deluge valve, 1SI-852A, had not been stroked tested per American Society of Mechanical Engineers (ASME) Section XI requirements since April 4, 1994. This valve was required to be stroke tested each cold shutdown (that is, every 12 months during refueling outages) in order to meet T/S 15.4.2.B.3 (Section M4.1).

- On December 27 and 28, 1996, the Unit 1 containment inner personnel hatch failed during Type B (10 CFR 50, Appendix J) leakage testing. Several test failures have been noted for this door during the previous inspection periods (Section M4.2).

Engineering

- On November 26, 1996, a helicoil repair was made to the Unit 2 "A" (2A) safety injection (SI) pump, 2P-15A. The repair did not meet all the requirements of Section XI Code Case N-496 (Section E2.1).

- On January 9, 1997, the licensee determined that there was a potential thermal overpressurization concern for the Unit 1 reactor coolant pump seal return piping that penetrated containment during a postulated design bases accident. Insulation was installed on the affected pipe section to mitigate this concern (Section E2.2).

- On January 24, 1997, the inspectors observed a pool of oil beneath the electric fire pump motor, P-35A. No CR was written nor was an operability evaluation performed for this condition (Section E3.1).

- The licensee determined that there may have been a potential in the past for the main steam safety valves (MSSVs) to not lift at the maximum assumed setpoint during a loss of external load. The licensee was aware in 1991 of the potential for a variation in the MSSV setpoint due to ambient temperature changes in 1991 (Section E4.1).

Plant Support

- The licensee discovered on December 29, 1996, that a Unit 1 steam generator blowdown filter outlet sample was not obtained and analyzed for gamma scan and tritium as required by Table 15.7.6-1 in TS 15.7.6 (Section R4.1).

- On January 23, 1997, security reestablished the Unit 2 containment as a vital area following steam generator replacement (Section S2.1).

Report Details

Summary of Plant Status

On December 17, 1996, Unit 1 reduced power from 100 percent to 90 percent due to station management's concerns with operations department performance after 2A RHR pump, 2P-10A, was run with the discharge valve shut for 38 minutes (Sections O3.1 and O4.1). Unit 1 continued to operate at 90 percent throughout the inspection period.

Unit 2 remained shutdown and defueled during the inspection period for the steam generator replacement refueling outage U2R22. Both replacement steam generators were hydrostatically tested during this period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations. During this inspection period, the inspectors observed Unit 1 and 2 control room shift turnovers, reviewed Operations' logs and daily observed control room operations.

The inspectors noted a better questioning attitude by auxiliary operators during most control room turnovers. The inspectors also noted increased use of the condition reporting system by operations personnel. During tours of the Primary Auxiliary Building, the inspectors noted improved material preservation of equipment and cleaning of boric acid leakage on equipment.

O2 Operational Status of Facilities and Equipment

O2.1 System Recovery and Restoration Program

a. Inspection Scope (71707)

A review of the new Nuclear Power Department Procedure (NP) 2.3.4, Revision 0, "System Restoration," was conducted by the inspectors.

b. Observations and Findings

On January 7, 1997, the licensee implemented a new "System Restoration" procedure. The purpose of this procedure was to establish a comprehensive method for returning systems to operation following maintenance outages.

The inspectors reviewed this procedure and the "System Restoration" binders created to track system restoration. The inspectors observed licensee personnel using the "RHR System Restoration" binder prior to filling and venting the RHR system on January 21 through 22, 1997.

c. Conclusions

The inspectors concluded that the new "System Restoration" procedure was more detailed and comprehensive than documentation used during previous outages for returning systems to service. The inspectors also concluded that the "System Restoration" binders would aid operations in restoring systems and this effort was viewed as positive.

04 Operator Knowledge and Performance

04.1 Unit 1 Power Reduction

a. Inspection Scope (71707)

The inspectors observed the licensee's power reduction from 100 percent to 90 percent. The following document was reviewed in support of this inspection:

- Operations Procedure (OP)-3A, Revision 37, "Normal Power Operation to Low Power Operation"

b. Observations and Findings

On December 17, 1996, the licensee reduced power on Unit 1 from 100 percent to 90 percent in accordance with OP-3A. This reduction in power was due to licensee management's concerns about the 2A RHR pump event which occurred the previous day (Section 04.2). Although this event did not affect the operation of Unit 1, plant management decided to reduce Unit 1 power to focus attention on the improper operation of the RHR pump.

The power reduction was performed by the Unit 1 control operator (CO) and a second licensed operator with oversight by a designated senior reactor operator.

The inspectors observed the operators using the correct procedure during the power reduction and observed proper communications between the shift personnel.

c. Conclusions

The inspectors concluded that the evolution was well planned and executed.

04.2 Unit 2 RHR Pump Operation with Discharge Valve Shut

a. Inspection Scope

A review of the licensee's incident investigation/root cause evaluation for the operation of the 2A RHR pump with its discharge valve shut and no recirculation flow path available was conducted. The following documents were reviewed:

- Root Cause Assessment of the Operation of the Unit 2 Residual Heat Removal Pump with the Discharge Valve Closed at Point Beach Nuclear Plant, dated January 16, 1997

- Operations Written Work Order 9613927, "Filling and Venting of the RHR System up to 2RH-716A & 2RH-716B and Testing of RHR Pumps"

- Nuclear Power Department Procedure (NP) 1.2.2, Revision 1, "Technical Procedure Classification, Review and Approval"

- Point Beach Test Plan (PBTP) 049, Revision 0, Unit 2 RHR System Fill and Vent

b. Observations and Findings

On December 16, 1996, the 2A RHR pump (2P-10A) was inadvertently operated for 38 minutes with its discharge valve shut (2RH-709A) and no recirculation flow path available. The system was being filled and vented after maintenance. The licensee formed an Incident Investigation Team (IIT) to investigate the circumstances surrounding this event.

The IIT concluded that the root cause was an error by the auxiliary operator (AO) who performed the initial valve lineup. The AO failed to reposition the pump discharge valve as required by the valve lineup list because of a place-keeping error. The IIT concluded that the AO should have been able to correctly align the system based on his knowledge and skills.

The IIT determined that the evolution was performed under an Operations Written Work Order (WO) vice an approved test procedure. The WO contained several valve lineups which listed valves in groups of up to 25 without delineators. The RHR pump discharge valve, 2RH-709A, was supposed to be repositioned open. This valve was listed in the middle of the lineup, but should have been opened last. The AO skipped this valve intending to come back to it at the end of the valve lineup. When the last valve on the list was repositioned, the AO left the area without having opened 2RH-709A.

The IIT further determined that the AO used a field copy of the valve lineup to prevent radioactive contamination of the master copy. After repositioning the last valve on the valve lineup, the AO updated the master copy of the work order by initialing the line next to the top valve in the lineup and drawing a vertical line down through all the initial lines next to each valve in that section. The AO did not review the field copy; he had forgotten that 2RH-709A was still shut.

The inspectors questioned the operator as to why he skipped over valve 2RH-709A with the intent to reposition it at the end of the lineup. He stated that he was instructed through "on-the-job" training with another AO that valves required to be shut should be shut first and valves required to be opened should be opened last.

The IIT identified 17 concerns associated with this event. These concerns were grouped into the following 6 categories:

- Unclear management expectations for the conduct of valve lineups and the use of work plans/procedures with signoffs
- Inadequate command, control, coordination, and communication by the evolution supervisor
- The use of a non-safety related work plan and work order for post-maintenance testing and operability testing of a safety-related system
- Configuration control
- Valve mispositioning and danger tag events
- possible Duty Shift Superintendent (DSS) distraction due to illness and exhaustion

The IIT provided recommendations in the Root Cause Assessment document that covered the six categories identified above. The recommendation regarding the use of an Operation Written Work Order to test safety-related components was to review the overall practice of using work plans as part of the formal post-maintenance test (PMT) used for operability and return-to-service testing of safety-related components. The IIT also noted that if work plans continued to be used for evolutions similar to the event in the investigation, that human factors concerns were included in the writing of the work plan.

The licensee reperformed the fill and vent on the 2A RHR system on January 22, 1997. The procedure used, PBTP 049, was an approved test procedure.

c. Conclusions

The inspectors agreed with the IIT root cause assessment and most of the corrective actions. However, the inspectors were concerned that the IIT recommendation did not conclusively state that approved procedures for testing safety-related components would be used in all future testing.

The failure of the AO to open the RHR pump discharge valve, 2RH-709A, as required by the valve lineup list is an example of a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," which requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and be accomplished in accordance with these instructions, procedures, and drawings (VIO 50-266(301)/96019-01a(DRP)). Although the valve mispositioning was identified by the licensee and a thorough investigation was conducted, corrective actions taken for a previous valve mispositioning error involving the auxiliary feedwater system (Inspection Report No. 50-266(301)/96006) should have prevented this event.

O7 Quality Assurance in Operations

O7.1 Plant On-Site Review Committee Meeting Observations (40500)

The inspectors observed three Manager's Supervisory Staff meetings (MSSM) including MSSM 97-02. Issues discussed included procedures and safety evaluations (SEs) for testing of containment penetrations P12b and P30a and stroke testing of RHR/Low Head Core Deluge valve, 1 SI-852A. Issues discussed during MSSM 97-02 included turbine-driven auxiliary feedwater pump, 2P-29, PMT issues, and the missed Unit 1 chemistry T/S surveillance test documented in Licensee Event Report (LER) 266/96-014.

Several examples of committee members displaying good questioning attitude and challenging of staff information were observed by the inspectors. The inspectors have continued to note improvements in committee members' questioning attitude during recent MSS meetings.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Inspector Follow-up Item (IFI) 301/94013-05(DRP): Reactor Coolant System (RCS) Leakage Increase and Piping Pressure Wave

On July 17, 1994, after the 2A SI pump was used to fill the 2B SI accumulator, licensee personnel noted that the level in the pressurizer relief tank (PRT) was increasing. An RCS leak rate calculation determined that 0.3 gallons per minute (gpm) was leaking through the SI line check valve, SI-867B, and test line valve, SI-839D, and out the test line header relief valve, SI-887B, into the PRT. This leakage path was confirmed on July 19, 1994, by measuring elevated temperatures on the suspected flow path.

The licensee determined that the leak rate was limited by leakage past air-operated valve (AOV), SI-839D, which used spring pressure to seat the disc. The licensee believed that the valve disc came off its seat when the 2A SI pump was started because of a slight pressure wave from the pump. This allowed RCS pressure to lift the SI-887B relief valve.

The licensee analyzed the worst case scenario and calculated that a 4,800 pounds per square inch - gauge (psig) pressure wave was possible during the evolution. The licensee initially determined that no water hammer or hydraulic transient occurred based on the piping having been properly filled and vented, piping walkdowns, and the absence of any sounds being heard by operators during the event.

On July 20, 1994, after performing an engineering analysis and discussions with the AOV vendor, licensee personnel entered containment, installed a pressure gage at a test connection near relief valve SI-887B and increased the spring pressure on SI-839D. Subsequently, the gage pressure started falling and the PRT level stopped increasing. Within about 15 minutes of increasing the AOV spring pressure, the leak was stopped.

As part of the licensee's investigation into the cause of the increased RCS leakage, accumulator fill evolutions were monitored on Unit 1 and Unit 2 to determine if pressure surges in the SI test line during the fill could have affected the position of SI-839D. The results of the monitoring showed that pressure surges on the order of 1850 psig to 2073 psig occurred during accumulator fill evolutions. These pressure surges were above the test line relief valve SI-887B setpoint. After these pressure surges were determined, the licensee performed calculations which showed that the SI test line and supports were not overstressed.

The licensee decided to reduce the pressure surge by slowing down the accumulator fill rate by throttling the globe valves downstream of the accumulator fill AOVs. The licensee stated that the pressure surge caused by valve slam was directly proportional to the flow rate in the pipe just before the valve closes. The flow rate was reduced from 150 gpm to 20 gpm which reduced the calculated pressure surge to less than the test line relief valve setpoint. The globe valves were locked in the throttled position and Operating Instruction (OI)-100, Revision 6, "Adjusting SI Accumulator Level and Pressure" was changed to state the new fill rate.

The licensee investigated the July 17, 1994, 2B accumulator fill evolution to determine if there were any deviations from the normal filling method which may have contributed to this event. The licensee concluded that no evidence could be found that plant conditions or the method of filling the accumulator contributed to the opening of SI-839D.

The inspectors had no concerns with the licensee's stress calculations, root cause, or corrective actions. This issue is considered closed.

<u>(Closed) Confirmatory Action Letter (CAL) No. RIII-96-012:</u> The CAL concerned the adequacy of the volume of control room annunciator alarms, the adequacy of licensed reactor operator hearing, and the ability of the Duty Technical Advisor to respond within 10 minutes to the control room. In a letter dated September 9, 1996, the licensee adequately responded to the CAL. In addition, the CAL issues were discussed at a pre-decisional enforcement conference on September 12, 1996, as part of an escalated enforcement action. In a letter dated January 31, 1997, the licensee again addressed the CAL issues as part of the response to the Notice of Violation and Proposed Imposition of Civil Penalties that resulted from the escalated enforcement action. The CAL is closed and the CAL issues will be reviewed as part of the overall NRC review of the licensee's January 31, 1997, response. An IFI will

track NRC review of a licensee commitment in the September 9, 1996, response to establish and implement by March 31, 1997, a formalized self-assessment program to periodically assess all aspects of control room conduct (IFI 50-266(301)/96019-02(DRP).

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:

- WO 99370, "P-012A&B Spent Fuel Pool Pumps Design Basis Flow Test"
- Inservice Test (IT)-11A, Revision 1, "Performance Test for Spent Fuel Pool Heat Exchanger HX-13A/B"
- IT-05, Revision 32, "Containment Spray Pumps and Valves (Quarterly) Unit 1"
- IT-07, Revision 24, "Service Water Pumps and Valves (Quarterly)"
- Routine Maintenance Procedure (RMP) 9008-1, Revision 14, "Residual Heat Removal Pump Removal and Installation"
- IT-14, Revision 11, "Quarterly Inservice Test of Fuel Oil Transfer System Pumps and Valves"
- RMP-110B. Revision 5, "G-01 Redundant Systems Six Month Post-Diesel Annual Check"
- RMP-110B, Revision 5, "G-02 Redundant Systems Six Month Post-Diesel Annual Check"
- Installation Work Plan (IWP) 95-042A, "Modification of Valves 2SI-857A&B Unit 2"
- Technical Specification Test (TS)-83, Revision 4, "Emergency Diesel Generator G-03 Monthly"
- TS-71, Revision 14, "Monthly Electric Motor-Driven Fire Pump Functional Test"

- PBTP 049, Revision 0, "Unit 2 RHR System Fill and Vent"
- WO 9700220, "P-32E Service Water Pump High Vibrations"

The work performed under these activities was professional and thorough. Technicians were experienced and knowledgeable of their assigned tasks. The work package was present at the jobsite 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 Unit 2 Secondary Hydrostatic Testing of New Steam Generators

a. Inspection Scope (61726)

The inspectors reviewed PBTP-041, Revision 2, "Hydrostatic Test of Unit 2 HX-1A Steam Generator" and PBTP-042, Revision 2, "Hydrostatic Test of Unit 2 HX-1B Steam Generator" during observations of these surveillance activities.

b. Observations and Findings

The inspectc observed hydrostatic testing of both steam generators, 2HX-1A and 2HX-1B. The inspectors verified that required hydrostatic test pressures were reached and stabilization times were met prior to the start of testing. The inspectors looked for leakage inside the steam generator bowls and on the piping, instrument lines, manways, and handholes. Slight leakage was noted at hydrostatic pressure at the manways and handholes. No other leakage was noted and inside the bowls remained dry. Licensee testing staff examined all required areas of the steam generators and found no deficiencies.

c. Conclusions

The testing was well performed and the inspectors had no concerns.

M3 Maintenance Procedures and Documentation

M3.1 High Fuel Oil System Pressure Alarm on EDG G-03

a. Inspection Scope (61726)

The monthly test of EDG G-03 was observed in December 1996 and January 1997 and the following documents were reviewed:

- TS-83, Revisions 3 and 4, "Emergency Diesel Generator G-03 Monthly"
- Final Safety Analysis Report (FSAR) Section 8.2.3, "Emergency Power"

- NP 5.3.1, Revision 4, "Condition Reporting System"

- CR 96-1856, "High Fuel Oil System Pressure Alarm on G-03 EDG"

b. Observations and Findings

On January 21, 1997, TS-83 was performed to satisfy the normally scheduled monthly callup (routine surveillance). During performance of step 4.15, the EDG was accelerated to rated speed. Once the diesel engine reached 900 rpm, the inspectors observed the EDG engine fuel oil pump discharge pressure indicator reading approximately 61 psig. The normal range for this reading on the EDG logs was 20 to 50 psig. The operator did not notice this reading until he received the Low/High Fuel Oil Pressure alarm. At this point, the reading was approximately 56 psig. The EDG operator reported the reading to the control room. The DSS said that the discharge pressure would decrease as the diesel was loaded.

Once the EDG was loaded to 2500 kilowatt (kW), the inspectors noted that the reading was approximately 48 psig and was within the normal range listed on the logs.

During the last performance of TS-83 on December 26, 1996, CR 96-1856 was written stating that the fuel oil system pressure high/low alarm was received after the generator field was flashed in step 4.13. Upon investigation, the fuel oil system pressure was high by approximately 10 psig. The G-03 fuel oil filters were changed out and TS-83 was reperformed. The Low/High Fuel Oil Pressure alarm was not received during the subsequent test. Although CR 96-1856 was not closed out at the end of the inspection period, no corrective action or evaluation was contained on this CR other than changing out the fuel oil filters.

The inspectors noted that no CR was written for the high fuel oil pressure alarm received during the performance of TS-83 on January 21, 1997.

c. Conclusions

The inspectors were concerned that since no CR was written for the alarm received during the January 21 test that no reevaluation of the condition took place and no examination of any operability concerns occurred.

Step 1 of Attachment A to NP 5.3.1 states that a CR should be initiated for nonconformances that may appear to be adverse to the safe and orderly conduct of the operation of PBNP, and Example 7 in Attachment A notes that discrepancies associated with alarms that were conditions that may affect equipment operability warrant initiation of a CR. The inspectors concluded that the high fuel oil pressure alarm received during the performance of TS-83 on January 21, 1997, was a condition that could affect EDG operability.

The failure to write a CR was contrary to NP 5.3.1 and an example of a violation of 10 CFR 50, Appendix B, Criterion V (VIO 266(301)/96019-01b(DRP)).

M4 Maintenance Staff Knowledge and Performance

M4.1 Missed Surveillance Test for the Unit 1 RHR/Low Head Core Deluge Valve

a. Inspection Scope (37551 & 61726)

The at-power stroke test of the RHR/Low Head Core Deluge Valve, 1SI-852A, was observed. The following documents were reviewed:

- PBTP 048, Revision 0, "Full Stroke Open Test of 1SI-852A"
- SE 97-007, Revision 1, PBTP 048, "Full Stroke Open Test of 1SI-852A"
- CR 97-136, "Missed Technical Specification Surveillance Test"
- Point Beach Memorandum (PBM) 96-542, "Self Assessment of Safety Related Equipment Testing"
- FSAR Section 9.3, "Auxiliary Coolant System"

b. Observations and Findings

On January 16, 1997, the licensee discovered that the Unit 1 RHR/low head core deluge valve, 1SI-852A, had not been stroke tested per ASME Section XI since April 4, 1994. This valve was required to be stroked tested each cold shutdown (typically each annual refueling outage) per ASME Section XI and T/S 15.4.2.B.3. The discovery was made during the final reviews of valve inservice testing (IST) being performed to verify that stroke timing IST acceptance criteria bounded design basis requirements. These reviews were part of the licensee's corrective actions for surveillance testing violations discussed in Inspection Report 50-266(301)/96006 and at the pre-decisional enforcement conference on September 12, 1996.

Previous stroke testing of 1SI-852A was performed during cold shutdowns to limit radiation exposure for the local position verification. Similar valves 1SI-852B, 2SI-852A, and 2SI-852B were all stroke tested within the required periodicity during PMTs.

The plant simulator was used to test various scenarios which could be encountered during performance of this test. Feedback from the simulator runs was incorporated into the test procedure.

On January 17, 1997, the inspectors observed the performance of PBTP 048. This procedure stroked 1SI-852A as required by ASME Section XI while Unit 1 was at 90 percent powe The inspectors compared the valve stroke times with acceptance criteria and noted that the times were acceptable.

On October 2, 1996, the licensee issued PBM 96-542. In this self-assessment, the licensee noted that several relief and check valves were not controlled by the existing licensee callup systems. This assessment noted that this condition could result in these valves not being tested on their required frequency. Section XI valves and their IST requirements were looked at during this assessment.

The inspectors reviewed CR 97-136 and discussed the corrective actions for the missed T/S surveillance testing of 1SI-852A with the cognizant engineer and site engineering management. Licensee management stated in the exit meeting on January 29, 1997, that the existing system for calling up T/S-required surveillance testing may not include all equipment required to be tested. The inspectors were concerned that other T/S equipment may not be tested at the frequency required. Also, the inspectors were concerned that the licensee's corrective action for this issue was not comprehensive enough to ensure that all equipment was tested at the frequency required.

c. Conclusions

The inspectors concluded that the performance of PBTP 048 was well-planned and professionally executed.

However, the inspectors also concluded that inadequacies existed in the licensee's systems for ensuring that equipment was tested at its required frequency. Also, the inspectors were concerned that corrective actions, committed to by the licensee at the end of the inspection period, were not comprehensive enough to prevent recurrence of this condition for other required T/S equipment.

T/S 15.4.2.B.3 required that IST of ASME Code Class 1, 2, and 3 valves be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code (1986) and applicable Addenda as required by 10 CFR 50.55a. Section IWV-3412(a) of Section XI requires that valves that cannot be exercised during plant operations be full-stroke exercised during cold shutdowns. Contrary to this, 1SI-852A, an ASME Code Class 2 valve that could not be exercised during plant operations, was not stroke tested during the two refueling outages (in the spring of 1995 and 1996) between April 4, 1994 and January 17, 1997, a violation of T/S 15.4.2.B.3 (VIO 50-266/96019-03(DRP)).

M4.2 Unit 1 Containment Inner Hatch Surveillance Test Failure and Corrective Maintenance

a. Inspection Scope (61726 & 62707)

On December 27 and 28, 1996, the Unit 1 containment inner personnel hatch failed its leakage test during the two performances of TS-10A, Appendix B. The following documents were reviewed by the inspectors during their evaluation of these failures:

- CR 96-1860, "Unit 1 Containment Hatch Exhibited Higher Than Normal Leakage"
- CR 96-1870, "Potential Failure of Containment Upper Hatch"
- WO 9614145, "Personnel Access Air Lock Excessive Leakage"
- T/S 15.4.4, "Containment Tests" and T/S 15.3.6, "Containment System"
- Containment Leakage Rate Testing (CLRT) Program, Revision 0
- TS-10A, Appendix B, Revision 13, "Hatch Door Seals Unit 1"
- FSAR Section 5, "Containment System"

b. Observations and Findings

The Unit 1 inner and outer hatch door seals were vacuum tested on December 27, 1996, as allowed by T/S 15.4.4.I and the CLRT program. Operations personnel secured the Unit 1 forced vent and equalized pressure across the inner door prior to performing TS-10A, Appendix B. The licensee had previously told the inspectors that they believed that the forced ventilation was the cause of previous inner door test failures.

The inner door leakage exceeded acceptance criteria given in TS-10A, Appendix B but was not above criteria which required a full pressure test of the airlock. The inner door o-rings were replaced and the door alignment was adjusted per WO 9614145. Subsequent initial testing met TS-10A, Appendix B acceptance criteria.

On December 28, 1996, during final testing of the inner door, significant air leakage was noted by testing personnel around the shaft seal on the remote operator for the inner door. The leakage noted exceeded T/S 15.4.4.I and the CLRT program requirements. The inner door was appropriately declared inoperable and the T/S 15.3.6.A.1.d.(3) limiting condition for operation (LCO) was entered.

Maintenance personnel replaced the quad-ring shaft seal that failed, the inner door passed a full pressure airlock test per CLRT requirements, and the LCO was exited.

Several failures of the inner personnel hatch door during TS-10A, Appendix B testing have been documented in Inspection Reports 50-266(301)/96012(DRP) and 50-266(301)/96015(DRP). The inspectors noted a concern in Inspection Report 50-266(301)/96012(DRP) that the licensee had not fully analyzed nor determined the root causes of the inner door test failures.

c. Conclusions

The inspectors were concerned with the continued failures of the inner personnel hatch door during TS-10A, Appendix B testing. The inspectors were also concerned that the root causes of the leakage problem have not yet been identified. This is considered an IFI pending further review by the inspectors of inner personnel hatch door testing, the licensee root cause investigation, and corrective actions for this issue (IFI 266/96019-04(DRP)).

III. Engineering

E1 Conduct of Engineering

E1.1 Engineering Reviews During the Inspection Period

Based on the large number of 10 CFR 50.72 reports issued during this inspection period, the inspectors have noted that engineering personnel have been re-analyzing old assumptions, displaying a more questioning attitude, and reporting concerns raised. The inspectors viewed all these developments as positive.

E2 Engineering Support of Facilities and Equipment

E2.1 Helicoil Repair to 2A SI Pump

a. Inspection Scope (37551)

An inspection of a helicoil repair to the 2A SI pump, 2P-15A, was performed. The following documents were reviewed:

- FSAR Section 6.2, "Safety Injection System"
- NP 7.2.5, Revision 3, "Repair/Replacement Program"
- ASME Boiler and Pressure Vessel Code, 1986 edition, no addenda, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components"
- Regulatory Guide 1.147, Revision 11, "Inservice Inspection Code Case Acceptability ASME Section XI Division 1"

b. Observations and Findings

On November 26, 1996, the inspectors reviewed a helicoil threaded insert repair of a bolt hole on the 2P-15A casing. The inspectors questioned the licensee concerning whether or not the repair was performed in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code. On December 17, 1996, the licensee informed the inspectors that helicoil repairs had inappropriately been exempted in NP 7.2.5 (paragraph 1.5.10), the licensee's governing procedure for Section XI of the ASME B&PV Code.

Footnote 6 to 10 CFR 50.55a(g) stated that Regulatory Guide 1.147, "Inservice Inspection Code Case Acceptability - ASME Section XI, Division I," listed Code Cases that were considered acceptable for use with Section XI components, such as the 2P-15A SI pump. Code Case N-496, listed in Regulatory Guide 1.147 as acceptable, specified six requirements that applied to the use of helical-coil (helicoil) threaded inserts. After the licensee determined that Code Case N-496 applied to the helicoil repair, the licensee evaluated the repair and determined that the six requirements of the Code Case N-496 had been met; however, extensive evaluation was required to show that the repair met the requirement that the insert satisfy original construction loading limits for the threaded connection.

The failure to include instructions for meeting Code Case N-496 in the NP 7.2.5 or in the WO used for the repair on the SI pump is an example of a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," which requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and be accomplished in accordance with these instructions, procedures, or drawings (VIO 301/96019-01c(DRP)).

When the inspectors questioned the licensee after the repair was completed, none of the code case requirements were documented as being met. NP 7.2.5 was subsequently revised to ensure that Code Case N-496 requirements were applied to helicoil repairs.

c. Conclusions

The inspectors determined that appropriate instructions had not been provided in a procedure or WO for a helicoil repair on the 2P-15A SI pump. After an extensive evaluation the licensee determined that the repair met established ASME Section XI criteria. The licensee subsequently revised its ASME "Repair and Replacement" program governing procedure to ensure that appropriate instructions would be provided for future helicoil repairs.

E2.2 Potential Overpressurization of Isolated Piping in Containment During a Large Break Loss of Coolant Accident (LBLOCA)

a. Inspection Scope (37551)

An inspection into the licensee's evaluation of thermally induced overpressurization of isolated water-filled piping sections in containment was conducted. The evaluation was in response to Generic Letter (GL) 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions." The following documentation was reviewed by the inspectors:

- GL 96-06, dated September 30, 1996
- Wisconsin Electric Calculation 97-06, 1/9/97, "Operability Determination for Containment Penetration P-11 Trapped Fluid Pressurization"

- Wisconsin Electric Letter, VPNPD-96-090, "Dockets 50-266 and 50-301 GL 96-06 Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions Point Beach Nuclear Plants, Units 1 and 2"

- Design Change Package WO 9700318, 1/9/97, "Seal Water Return Line Insulation (Unit 1)"

- FSAR Section 9.2, "Chemical and Volume Control System"

b. Observations and Findings

There were three issues of concern in GL 96-06. The inspection dealt with the third issue, the thermally induced overpressurization of isolated water-filled piping sections in containment which could jeopardize the ability of accident-mitigation systems to perform their safety functions. The overpressurization could also lead to a breach of containment integrity via bypass leakage.

On October 30, 1996, the licensee issued letter VPNPD-96-090 which responded to the GL. In this letter, the licensee stated that there were six water-filled piping sections in each containment which were potentially susceptible to thermally-induced overpressurization. These sections would be evaluated and the results of the evaluations and subsequent corrective actions would be provided in the 120-day response to the GL.

On January 9, 1997, the licensee determined that five of the six potentially susceptible water-filled piping sections discussed in the October 30 letter did not have overpressurization concerns. The initial analysis for the sixth piping section, which assumed that the piping inside containment was insulated, concluded that there was no overpressurization concern. However, after previous system walkdown information was reviewed, the licensee discovered that the piping--Unit 1 reactor coolant pump (RCP), chemical and volume control system (CVCS), seal return piping--was not insulated. The licensee revised the analysis and concluded that thermal overpressurization for this isolated water-filled piping section was a concern.

On January 9, 1997, the licensee issued a four-hour report in accordance with 10 CFR 50.72(b)(2)(iii)(C) for this issue. This condition would occur during a large break LOCA (LBLOCA) when both the inboard and outboard containment isolation valves in this seal return piping shut. The heat input from the LBLOCA to the isolated section of pipe would heat the trapped liquid overpressurizing the pipe. The licensee declared the containment inoperable and entered a one-hour T/S LCO. The LCO was exited after the breaker for one of the isolation valves, 1CV-313, was tagged open so that the valve would not close on a containment isolation signal. The opening of the breaker effectively removed the overpressurization potential. A four-hour T/S LCO was then entered for the inoperable containment isolation valve.

The licensee then installed thermal insulation on the seal return pipe which eliminated the overpressurization concern. The licensee subsequently removed the danger tag from the containment isolation valve, restored the breaker to its normal position, and exited the LCO.

c. Conclusions

The inspectors had no concerns with the licensee's actions to correct the potential thermal overpressurization condition and concluded that the licensee properly entered and exited all T/S-required LCOs during resolution of the issue.

E3 Engineering Procedures and Documentation

E3.1 Oil Leakage From Electric Fire Pump P-35A Motor

a. Inspection Scope (61726 & 37551)

On January 24, 1997, the inspectors observed a pool of oil beneath the electric fire pump motor, P-35A. Portions of the following documents were reviewed during inspection of this issue:

- WO Request 9611753, "Large Amount of Oil on Base of Electric Fire Pump Motor, P-35A"
- TS-71, Revision 14, "Monthly Electric Motor-Driven Fire Pump Functional Test"
- NP 5.3.1, Revision 4, "Condition Reporting System"
- NP 8.1.1, Revision 2, "Work Order Processing"
- T/S 15.3.14, "Fire Protection System"
- FSAR Section 9.6.1, "Fire Protection System"

b. Observations and Finding

On January 24, 1997, the inspectors notified operations of the oil beneath the P-35A motor and an AO was dispatched to the pump. The inspectors also noted a WO tag for request 9611753 hanging on the motor. The work order tag had been written on October 23, 1996. Further review by the inspectors determined that no CR had been written for the oil leak, and that the system engineer indicated that he thought the WO had been written to cleanup oil that spilled during filling of the motor oil reservoir. Because this condition was only documented with a WO tag, no operability determination was made for the P-35A pump. NP 8.1.1, the WO procedure, noted that conditions requiring a CR should be documented per NP 5.3.1, which also requires an operability determinations be performed for certain condition.

On January 27, 1997, the inspectors observed performance of TS-71. All required acceptance criteria in the 10-minute test were met; however, the inspectors observed oil leaking from the motor during the test. No CR was written to document the oil leakage; however, the AO performing the test did note the leakage in the test procedure. The inspectors reviewed the results of two additional TS-71 tests conducted after the October 23rd date when the WO tag was hung. Neither of these tests documented any oil leakage from the P-35A motor.

The inspectors were informed during discussions with the system engineer that the motor was scheduled to be repaired during the first week of February 1997.

c. Conclusions

The inspectors were concerned that no CR was written nor was an operability evaluation conducted for the oil leak condition and no reanalysis of the cause of the oil leakage was performed.

Step 1 of Attachment A to NP 5.3.1 stated that a condition report should be initiated for nonconformances that may appear to be adverse to the safe and orderly conduct of the operation of PBNP. Attachment A also stated that conditions that may affect equipment operability warrant initiation of a CR. The inspectors concluded that the oil leakage from the P-35A electric fire pump motor was a condition that may affect equipment operability and thus warranted a CR.

10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," required that activities affecting quality be prescribed by documented procedures of a type appropriate to the circumstances and be accomplished in accordance with these procedures. The failure to write a CR for the oil leak on October 23, 1996, or during any subsequent TS-71 monthly tests was contrary to procedure NP 5.3.1 and is considered an example of a violation Criterion V (VIO 266(301)/96019-01c(DRP)).

E4 Engineering Staff Knowledge and Performance

E4.1 Main Steam Safety Valve (MSSV) Setpoint Drift

a. Inspection Scope (37551)

An inspection was conducted of the licensee's response to Information Notice (IN) 96-03, "MSSV Setpoint Variation as a Result of Thermal Effects." IN 96-03 was issued on January 5, 1996, to alert licensees to a possible source of variation in the setpoint of safety valves as a result of changes in temperature in and around the valves. The following documents were reviewed by the inspectors:

- IN 89-90, Supplement 1, 4/3/91, "Pressurizer Safety Valve Lift Setpoint Shift"
- IN 96-03, 1/5/96, "MSSV Setpoint Variation as a Result of Thermal Effects"

- Wisconsin Electric Memo, NPM 91-0718, 5/30/91, "Evaluation of Information Notice #89-90 and Supplement #1"

- Wisconsin Electric Memo, NPM 93-0215, 4/6/93, NRC Information Notice 93-02 "Malfunction of a Pressurizer Code Safety Valve"

- Operability Determination dated 11/21/96, "Unit 1 and Unit 2 MSSVs"

- Operability Determination dated 12/31/96, "1MS-02007, 1MS-02012, 1MS-02013, 2MS-02007, 2MS-02011 MSSVs"

- Operability Determination dated 1/03/97, "1MS-02007, 1MS-02012, 1MS-02013, 2MS-02007, 2MS-02011 MSSVs"

- FSAR Section 14.1.9, "Loss of External Electrical Load"

b. Observations and Findings

On April 23, 1996, in response to Information Notice 96-03, the licensee determined that the MSSVs were tested at ambient temperatures of 70°F to 80°F. These valves typically saw in-service, ambient temperatures between 0°F and 100°F, depending on outside air temperature.

On November 21, 1996, the licensee issued an operability determination for the MSSVs based on the results of setpoint testing at Wyle Laboratories. The Wyle test results showed that the MSSV setpoints were different at full pressure lift conditions than the setpoints of MSSVs tested with a lift assist device. Also, additional testing at Wyle showed that setpoints varied with ambient temperature during testing.

The operability determination adjusted the setpoint of the MSSVs based on the Wyle setpoint drift test data and concluded that all Unit 1 MSSVs would relieve at full capacity below the maximum setpoint assumed in the current Unit 1 accident analysis.

The licensee issued a second operability determination on December 31, 1996, which concluded that worst case scenarios were not used in the first operability determination. The second operability determination used worst case adjusted setpoints and concluded that the MSSVs may exceed their design basis pressure setpoint for the loss of external load analysis. On December 31, 1996, the licensee made a four-hour report in accordance with 10 CFR 50.72(b)(2)(iii)(D) stating that there may have been a potential in the past that the MSSVs would not have lifted at the maximum assumed setpoint.

The second operability determination also stated that maintaining the MSSVs above 40.3°F would provide necessary margin to be within the accident analysis. The licensee erected a tent over the Unit 1 MSSVs and verified valve temperatures remained greater than 40.3°F.

A third operability determination was issued on January 3, 1997, which concluded that the MSSVs for Unit 1 were operable based on a parametric comparison of key inputs and a quantification (with a sensitivity analysis) of the effect of these key inputs on the results of a revised loss of external load analysis. The revised loss of load analysis modeled the MSSVs as lifting at the design setpoint and accounted for head losses between the steam generators and the MSSVs.

On April 3, 1991, Supplement 1 to IN 89-90, "Pressurizer Safety Valve Lift Setpoint Shift," was issued. The purpose of this supplement was to alert licensees to environmental factors that may affect the lift setpoint of all safety (relief) valves, including MSSVs.

The licensee issued memo, NPM 91-0718, dated May 30, 1991, titled "Evaluation of Information Notice #89-90 and Supplement #1." In this memo the licensee recommended that the MSSV setpoint test process be reviewed to confirm that the setpoint test was conducted at the same conditions as actual valve service. However, no actions were taken by the licensee until 1996.

c. Conclusions

The inspectors determined that the licensee was aware in 1991 of the potential for the MSSV setpoint to drift due to ambient temperature changes--a condition adverse to quality, but did not take prompt action to correct this condition. The problem was addressed on January 3, 1997.

10 CFR 50, Appendix B, Criterion XVI, required measures be established to assure that conditions adverse to quality be promptly identified and corrected. The failure to promptly resolve the MSSV setpoint issue is considered a violation of Criterion XVI (VIO 266/301-96019-05(DRP)).

E4.2 LBLOCA Delay Time Assumptions Not Correct

a. Inspection Scope (37551)

The licensee identified that the SI system full flow delay times may be greater than what was assumed in the LBLOCA analysis. The following documentation was reviewed during this inspection:

- FSAR Section 14.3.2, "Major Reactor Coolant System Pipe Ruptures (LOCA)"
- FSAR Section 8.2.3, "Emergency Power"
- Westinghouse Letter WES 74-47, dated 5/31/74, "Westinghouse Motors in Safety-Related Systems"
- Wisconsin Electric Calculation N-90-085, dated 10/17/90, "Safety Injection Pump Starting Curves"

- Wisconsin Electric Letter dated 2/4/81 "Dockets Nos. 50-266 and 50-301 Technical Specification Change Request No. 65 Point Beach Nuclear Plant Units 1 and 2"

- Wisconsin Electric Letter NPL 96-0391, dated 12/11/96, "Dockets 50-266 and 50-301 30 Day Report of ECCS Evaluation Model Changes, 10 CFR 50.46 Point Beach Nuclear Plant, Units 1 and 2"

b. Observations and Findings

While reviewing design basis valve closure times for the IST program, a licensee engineer discovered that the safety injection (SI) flow delay times may be greater than what was assumed in the LBLOCA analysis. This resulted in a one-hour report in accordance with 10 CFR 50.72(b)(1) for Unit 1 and a four-hour report in accordance with 10 CFR 50.72(b)(2)(i) for Unit 2 on January 8, 1997.

The LBLOCA analysis assumed that the high and low head SI systems were capable of delivering flow within 5 seconds and 17.7 seconds respectively. The licensee conservatively determined that the delay times (assuming offsite power available) for high head and low head SI flow could be 8 seconds for high head and 23.7 seconds for low head SI from the time an SI signal was generated.

The 8-second high head SI flow delay time consisted of a 2-second SI signal processing time, 1-second delay for sequencer plus uncertainty, and 5 seconds for the SI pump to start and get up to full speed. The 23.7-second low head SI flow delay time consisted of a 2-second SI signal processing time, 7-second delay for sequencer plus uncertainty, and 14.7 seconds for the low head pump to start and get up to speed.

The inspectors questioned the licensee regarding the basis for these delay times. The licensee stated that the 2-second SI signal processing delay time was based on response time test data from Westinghouse. The 1-second delay time for the high head pump and the 7-second delay time for the low head pump for sequencer delay plus uncertainty were based on information contained in section 8.2.3 of the FSAR. The 5-second delay for the high head pump to start and get up to speed was based on a Wisconsin Electric calculation, and the 14.7-second delay for the low head pump to start and get up to speed was based on information from Westinghouse.

The licensee performed a preliminary evaluation assuming the longer delay times of 8 seconds for high head and 23.7 seconds for low head SI flow from the time at which an SI signal was generated. This change resulted in a peak cladding temperature penalty of less than 50°F. The licensee stated that an additional 50°F penalty would result in a peak cladding temperature of 2187°F. The licensee concluded that the SI system was capable of performing its function to maintain the calculated LBLOCA peak centerline temperature below the acceptance criterion of 2200°F required by 10 CFR 50.46.

c. Conclusions

The inspectors had no concerns with the licensee's basis for the safety injection delay times or the licensee's analysis of the change to the peak cladding temperature.

E4.3 Potential Clogging of Refueling Cavity Drain Line During a LOCA

a. Inspection Scope (37551)

On January 20, 1997, the NRC was notified by the licensee in accordance with 10 CFR 50.72(b)(1) that sufficient water may not be available during a LOCA for the recirculation portion of the accident due to potential clogging of the refueling cavity drain. The inspectors reviewed the 10 CFR 50.72 notification; CR 97-169, "Safety Analysis Uncertainty Due to Water Being Held In the Lower Refueling Cavity"; CR 96-1848, "Material Certifications for Modification Package Are Incomplete"; and temporary changes to Emergency Operating Procedure (EOP) 1.3, "Transfer to Containment Sump Recirculation," during this inspection.

b. Observations and Findings

The current safety analysis for both Units at Point Beach assumed 184,185 gallons of water were delivered from the Refueling Water Storage Tank (RWST) to the RCS and containment sump following a LOCA. Sufficient RWST water delivery ensured enough water for recirculation and subcriticality. The analysis assumed that any water from the RCS or containment spray which entered the refueling cavity would drain into the containment sump.

While evaluating CR 96-1848, which questioned whether a flapper valve in the refueling cavity drain line could fail, the licensee determined that the lower refueling cavity may retain up to 46,000 gallons of water due to drain line clogging. If the 46,000 gallons of water was held in the refueling cavity, the amount of water removed from the RWST per the existing EOPs would not provide the 184,145 gallons required by the existing analysis.

The licensee changed EOP 1.3 to remove more water from the RWST to provide the required amount of water needed by the analysis. The inspectors reviewed the CRs associated with this issue and the changes to EOP 1.3.

c. Conclusions

The inspectors had no concerns with the licensee's immediate corrective action, changes to EOP 1.3, or the 10 CFR 50.72 notification. The inspectors will followup on any additional long term corrective actions during the review of the LER for this issue.

E8 Miscellaneous Engineering Issues

E8.1 <u>(Closed) Unresolved Item (URI) 266/94011-03(DRP):</u> Diesel Generator Cable Trays Contrary to Fire Protection Requirements

On June 6, 1994, the licensee discovered that three cable trays containing cables for the new diesel generator project were improperly routed. The new cable trays introduced intervening combustibles between the safe shutdown service water cable trays in the AFW pump room.

This condition was outside the 10 CFR 50, Appendix R exemption granted for the AFW pump room on July 3, 1985. The licensee performed a fire protection technical evaluation and an SE for this condition. Licensee interim actions taken upon discovery included attaching a single layer of Kaowool or equivalent fire barrier on the tops and bottoms of these open cable trays and conducting twice per shift fire watches in the AFW pump room.

After reviewing the technical adequacy of the licensee's actions, the inspectors considered this item closed based on the following:

1) An exemption was granted by the NRC on July 18, 1995, from the requirements of Section III.G.2.b of Appendix R to allow the intervening combustibles in the form of cable fill in three cable trays to remain installed in the AFW pump fire area. The NRC concluded that the plant configuration, administrative controls, and the fire protection provided for in the AFW pump fire area provided reasonable assurance that at least one train of equipment and cabling required to achieve and maintain safe shutdown would remain operable following a fire.

2) The licensee conducted fire protection training from August 1995 to May 1996 with their design engineers.

3) The licensee added references to their Design Control Checklists concerning fire protection requirements and compliance with the Fire Protection Evaluation Report, the licensee's documented fire protection program.

The three new cable trays which introduced intervening combustibles between the service water cable trays in the AFW pump room were contrary to the requirements of 10 CFR 50, Appendix R, Section III.G.2.b prior to the July 18, 1995, exemption. However, this violation is considered non-cited because the criteria specified in NUREG 1600, Criterion VII, Paragraph B.1 were met (NCV 266/301-96019-06(DRP)).

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.

From a radiological standpoint, the primary auxiliary building was in good condition, allowing access to most sections of the facility. Radiological housekeeping was generally good. During tours of the facility, the inspectors noted that barriers and signs were in good condition.

R4 Staff Knowledge and Performance in RP&C

R4.1 Missed Unit 1 Steam Generator Blowdown Sample

a. Inspection Scope (71750)

The inspectors investigated a missed Unit 1 steam generator blowdown filter outlet sample. The following documents were reviewed:

- T/S 15.7.6, "Radioactive Effluent Sampling and Analysis Requirements"
- LER 266/96-014, "SG Blowdown Sample Not Performed In Accordance With T/Ss"
- CR 96-1882, "Missed S/G Blowdown Filter Outlet Sample"

b. Observation and Findings

On December 29, 1996, the licensee discovered that the sample was not obtained and analyzed for gamma scan and tritium as required by Table 15.7.6-1 in T/S 15.7.6. The T/S required that the blowdown be sampled and analyzed for gamma emitters twice weekly.

The licensee's immediate actions included obtaining and analyzing a blowdown sample, reviewing primary to secondary leakrate data, reviewing the blowdown monitor data, and reviewing the service water discharge monitor data. These reviews showed that there was no increase in blowdown activity over this period.

The inspectors discussed this issue with Chemistry personnel. The inspectors learned that chemistry sample frequencies and schedules were identified in Chemistry procedure, CAMP-101, Revision 47, "Daily Routine Sampling Schedule for Operating, Refueling, or Shutdown Units." This procedure relied on the knowledge and experience of personnel performing the chemistry samples to know where all the sample requirements were located. The technician that missed the blowdown sample was required to analyze several other primary plant samples during his shift. The blowdown sample was listed in a different part of the procedure from the rest of the primary samples. The licensee made a temporary change to CAMP-101 to relocate the blowdown sample into the section which contained the rest of the primary samples requirements.

Additionally, the inspectors learned that there was no formal callup (routine activity schedule) system to notify the technician of required T/S samples to ensure that the sample testing frequency was met.

c. Conclusions

The inspectors had no concerns with the licensee's immediate corrective actions; however, the inspectors were concerned the lack of a formal callup system to notify the technician of required T/S samples to ensure that the sample testing frequency was met. Similar concerns with the licensee's adequacy in ensuring that T/S required equipment was tested within its frequency was discussed in Section M4.1.

This condition was contrary to the requirements of T/S 15.7.6.A, which required steam generator blowdown to be sampled and analyzed for gamma emitters twice weekly. However, this violation is considered non-cited because the criteria specified in NUREG 1600, Criterion VII, Paragraph B.1 were met (NCV 266/96019-07(DRP)).

S2 Status of Security Facilities and Equipment

S2.1 Security Revitalization of Unit 2 Containment (71750)

On January 23, security reestablished the Unit 2 containment as a vital area following steam generator replacement work. The inspectors walked down the outside of the Unit 2 facade and inside the facade, outside of containment. The inspectors also reviewed Point Beach Security Guidelines (PBSG) 7.2, Revision 0, "Vitalization of Unit 2," and discussed the revitalization with security personnel. The vital access doors into the facade were reactivated and the outside of the facade was enclosed prior to walkdown searches of the revitalized areas. The inspectors had no concerns with the revitalization of the Unit 2 containment.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to licensee management at the conclusion of the inspection on January 29, 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.

X2 Unit 2 Restart Commitments Management Meeting

On January 24, 1997, Point Beach management met with NRC regional staff at the NRC Region III office. This meeting was held to discuss the status of Unit 2 startup commitments that the licensee made in a letter dated December 12, 1996 and the NRC confirmed in a CAL dated January 3, 1997.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Wisconsin Electric Power Company (WEPCo)

A. J. Cayia, Plant Manager
T. G. Staskal, Acting Operations Manager
G. R. Sherwood, Maintenance Field Services Manager Maintenance
J. G. Schweitzer, Manager Site Engineering
P. B. Tindall, Health Physics and Chemistry Manager
D. F. Johnson, Manager-Regulatory Services and Licensing
T. C. Guay, Regulatory Services 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 Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-301/96019-01A	VIO	Criterion V violation for not following RHR valve lineup list
50-266(301)/96019-01B	VIO	Criterion V violation for failure to initiate CRs (2 examples)
50-301/96019-01C	VIO	Criterion V violation for failure to provided instructions on properly repairing a bolt hole on the 2A SI pump
50-266(301)/96019-02	IFI	Review commitment for formal control room self assessments
50-266/96019-03	VIO	Missed T/S surveillance test for Unit 1 RHR/low head core deluge valve
50-266/96019-04	IFI	Unit 1 containment inner personnel hatch test failures
50-266(301)96019-05	VIO	Criterion XVI violation for inadequate corrective actions for MSSV setpoint drift
50-266/96019-06	NCV	Diesel generator cable trays contrary to fire protection requirements
50-266/96019-07	NCV	S/G blowdown sample not performed in accordance with T/Ss

Closed

50-301/94013-05	IFI	RCS leakage increase and piping pressure wave
RIII-96-012	CAL	Control room activities
50-266/94011-03	URI	Diesel generator cable trays contrary to fire protection requirements

LIST OF ACRONYMS USED

AO	Auxiliary Operator
AOV	Air-Operated Valve
ASME	American Society of Mechanical Engineers
B&PV	Boiler and Pressure Vessel
CAL	Confirmatory Action Letter
CAMP	Chemistry Procedure
CFR	Code of Federal Regulations
CLRT	Containment Leakage Rate Testing
CO	Control Operator
CR	Condition Report
°F	Degrees Fahrenheit
DRP	Division of Reactor Projects
DSS	Duty Shift Superintendent
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ESF	Engineered Safety Feature
FSAR	Final Safety Analysis Report
GL	Generic Letter
gpm	Gallons per Minute
IFI	Inspection Followup Item
IIT	Incident Investigation Team
IN	Information Notice
IP	Inspection Procedure
ISI	Inservice Inspection
IST	Inservice Testing
IT	Inservice Test
IWP	Installation Work Plan
kW	Kilowatt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LBLOCA	Large Break Loss of Coolant Accident
LOCA	Loss of Coolant Accident
MSSM	Manager's Supervisory Staff Meeting
MSSV	Main Steam Safety Valve
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NP	Nuclear Power Department Procedures
NRC	Nuclear Regulatory Commission
OI	Operating Instruction
OP	Operations Procedure
OOS	Out-of-Service
PBM	Point Beach Memorandum
PBTP	Point Beach Test Plan
PMT	Post-Maintenance Testing
PRT	Pressurizer Relief Tank

psig	pounds per square inch - gauge
QA	Quality Assurance
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RMP	Routine Maintenance Procedure
RP&C	Radiological Protection and Chemistry Protection
SE	Safety Evaluation
SFP	Spent Fuel Pool
S/G	Steam Generator
SI	Safety Injection
T/S	Technical Specification
URI	Unresolved Item
VIO	Violation
WEPCo	Wisconsin Electric Power Company
WO	Work Order