U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No:	50-397/93-24
Docket No:	50-397
License No:	NPF-21
Licensee:	Washington Public Power Supply System P. O. Box 968 Richland, WA 99352
Facility Name:	Washington Nuclear Project No. 2 (WNP-2)
Inspection at:	WNP-2 site near Richland, Washington
Inspection Conducted:	June 22 - August 2, 1993
Inspectors:	R. C. Barr, Senior Resident Inspector D. L. Proulx, Resident Inspector K. E. Johnston, Project Inspector (July 19 - 23, 1993)

Approved by: [signature] for P. H. Johnson, Chief, Reactor Projects Section 1 — 8-27-93 Date Signed

Summary:

Inspection on June 22 - August 2, 1993 (Report No. 50-397/93-24)

Areas Inspected: Routine, announced, inspection by the resident inspectors of control room operations, licensee action on previous inspection findings, operational safety verification, surveillance program, maintenance program, licensee event reports, special inspection topics, and procedural adherence. During this inspection, Inspection Procedures 61702, 61705, 61706, 61707, 61726, 62703, 71707, 90712, 92700, 92701, and 92702 were used.

Safety Issues Management System (SIMS) Items: None.

Results:

General Conclusions and Specific Findings

Strengths:

Operators performed well and in a conservative manner in conducting the startup and power ascension following the R8 outage (paragraph 7).

The licensee aggressively repaired 27 steam leaks during the downpower on July 6, 1993, which improved the plant's material condition (paragraph 2).

Following the recognition that they had failed to implement a commitment, Quality Assurance management took swift action to implement the commitment and to counsel supervisors and staff on the importance of following through on corrective actions (paragraph 3.d).

Weaknesses:

Procedure quality and adherence appeared to require improvement in that two examples of apparent failures to follow procedures (concerning temporary modifications and fire protection), and two examples of inadequate procedures (the shutdown margin and heat balance procedures), were found (paragraphs 4, 5, and 7).

Systems Engineering involvement in resolving an oil leak in a residual heat removal (RHR) pump appeared to be weak (paragraph 4.c).

The licensee's process for dedication of commercial-grade material for safety-related valve HPCS-V-12 appeared to be weak (paragraph 9.b).

A documentation error in positioning control rods revealed weaknesses in the licensee's investigation and understanding of the event, the operator's logkeeping practices, and administrative controls for rod positioning (paragraph 9.a).

Quality Assurance failed to track and implement a plan to improve the prioritization, tracking and followup of corrective actions. The improvement plan had been established in response to a violation concerning QA's failure to followup corrective actions (paragraph 3.d).

Significant Safety Matters: None.

Summary of Violations and Deviations: Two apparent violations were identified involving failures to follow fire protection and temporary modification procedures (Paragraphs 4 and 7). One violation was identified involving inadequate procedures concerning the calculation of core thermal power and shutdown margin (Paragraph 5). One non-cited violation was identified regarding the failure to properly dedicate a commercial-grade part used in a safety-related valve's motor-operator (paragraph 9.b)

DETAILS

1. Persons Contacted

V. Parrish, Assistant Managing Director for Operations
*J. Gearhart, Quality Assurance Director
*J. Swailes, Plant Manager
*G. Smith, Operations Division Manager
*R. Webring, Technical Services Manager
*L. Harrold, Maintenance Division Manager
*G. Sorensen, Regulatory Programs Manager
J. Albers, Radiation Protection Manager
*R. Koenigs, Design Engineering Manager
*D. Larsen, Emergency Preparedness Manager
*T. Love, Chemistry Manager
*S. Peck, Equipment Engineering Manager
A. Hosler, Licensing Manager
*J. Benjamin, Quality Assessments Manager
*J. Peters, Administrative Manager
*J. Sampson, Maintenance Production Manager
*W. Sawyer, Acting Operations Manager
*J. Rhoads, Operating Events Analysis and Resolution Manager
*D. Coleman, Regulatory Services Supervisor
*R. Utter, Emergency Planning Operations Supervisor
*K. Meehan, Emergency Planning Supervisor
P. Inserra, Plant Technical Supervisor
*C. Fies, Licensing Engineer
*M. Eades, Licensing Engineer
*D. Swank, Licensing Engineer
*K. Lewis, Licensing Engineer
*K. Pisarcik, Licensing Aide
*D. Graham, Senior Fire Protection Specialist
*K. Newcomb, Fire Marshall

The inspectors also interviewed various control room operators; shift supervisors and shift managers; and maintenance, engineering, quality assurance, and management personnel.

*Attended the Exit Meeting on August 6, 1993.

2. Plant Status

At the start of the inspection period, the plant was operating at 20% power with reactor power ascension in progress following completion of the 1993 refueling outage (R8). The plant achieved 100% power on June 29, 1993. On July 6, 1993, reactor power was reduced to 60% to support repair of 27 steam leaks in the turbine building. The reactor was returned to full power on July 7, 1993. The plant remained at 100% power (except for temporary downpowers to 85% to support weekly control rod exercises and bypass valve testing) through the end of the inspection period.

3. Previously Identified NRC Inspection Items (92701, 92702)

The inspectors reviewed records, interviewed personnel, and inspected plant conditions relative to licensee actions on previously identified inspection findings:

a. (Closed) Violation 50-397/92-36-01, Component Labeling and Clearance Order Violation

During the report period encompassed by NRC Inspection Report 50-397/92-36, the inspector found a danger tag hung on a breaker that did not match the breaker number on the electrical cubicle which indicated that the Equipment Operators (EOs) apparently did not follow the licensee's procedure for clearance orders. Further investigation revealed weaknesses in the licensee's painting program, in that painters had removed the cubicle labeling to support painting and had placed the wrong identifying numbers on the cubicle at the motor control center. This resulted in a Notice of Violation (NOV). The licensee's corrective actions included correcting the errant motor control center labeling, counseling the equipment operators involved, providing required reading to all Operations personnel on this incident, walking down approximately 200 other motor control centers to ensure no other errors existed, revising the painting program procedures, and training all painters on the new painting program procedures. The inspector verified these actions were complete and considered them to be satisfactory. This item is closed.

b. (Closed) Violation 50-397/92-43-01, Four Examples of Procedure Violations

Inspection Report (IR) 92-43, issued March 22, 1993, included a violation for the following four examples of failure to follow procedures:

- Control room operators did not follow Plant Procedures Manual (PPM) 4.601.A1, which described the actions for responding to a control room annunciator for a high pressure core spray (HPCS) 125 VDC battery bus undervoltage.

- Licensee personnel did not initiate a "Problem Evaluation Request" (PER), as required by PPM 1.3.12, after observing anomalous reactor vessel level indications.

- The Shift Manager did not initiate a PER, as required by PPM 1.3.10, "Fire Protection Program," when a fire protection system impairment was brought to his attention by the resident inspector.

- Licensee personnel did not inspect the bottom of battery HPCS-B1-DG3 for the presence of sediment as required by Technical Specifications surveillance procedure PPM 7.4.8.2.1.23.

The inspection report noted that the licensee had taken actions to address the fourth example and did not need to provide a written response for that example. On April 20, 1993, the licensee provided a response to the other three examples of failure to follow procedures. The inspector reviewed the licensee's response and verified a sample of the corrective actions. This item is closed based on the following discussion:

(1) Failure to Follow HPCS Battery Undervoltage Annunciator Response Procedure

The licensee's actions to prevent recurrence included the counseling of all individuals involved in the event, on-shift training in the form of "Night Orders," which described the event and Operations management's expectations; a revision to the Conduct of Operations procedures to require completion of all procedural steps when a new alarm is received; and discussions conducted by the Operations Manager with all licensed operations personnel regarding alarm response procedures.

The inspector reviewed the Night Orders and found that they covered the event clearly and discussed management's expectations. The inspector observed operators responding to control room alarms and noted that they reviewed the annunciator response procedures when new alarms were observed and communicated clearly when expected alarms were received. The inspector discussed the annunciator response policy with operators and found that it was consistent with Operations management's guidance. This item is closed.

(2) Failure to Initiate a PER After Observing Anomalous Reactor Vessel Level Indications

This example of failure to follow procedures concerned the licensee's failure to initiate a PER in a timely manner to address the anomalous reactor vessel level indications observed on January 21, 1993. To address both the level anomalies and the timeliness of the PER, Plant Operations initiated a PER (PER 293-169) and QA issued a quality finding report (QFR 293-0009). The inspector reviewed both PER 293-169 and QFR 293-0009 and found them to be acceptable. The licensee committed in their response to the violation that PPM 1.3.12 would be revised by July 2, 1993, to better establish the criteria for addressing operability and for initiating a PER. The licensee informed the NRC, by letter dated July 30, 1993, that it plans to complete revisions to PPM 1.3.12 by August 31, 1993. A review of the revisions of PPM 1.3.12 will be conducted as part of Followup Item 50-397/93-24-01 (see paragraph 3.g). This item is closed.

(3) Failure to Initiate a PER Following Discovery of a Fire Protection System Impairment

The example cited in this violation involved workers propping a fire door open for convenience. The licensee concurred with the inspector's assessment that PPM 1.3.10, "Fire Protection Program" required that a PER be initiated. However, they concluded that a PER was not necessary since workers were within the line of sight of the door and therefore there was no threat to the fire protection of the plant. The licensee revised PPM 1.3.10 to require PERs to be initiated only if the fire impairment violation is a threat to the fire protection of the plant. In addition, the procedure was revised to state that an impairment was not needed if an individual was "...within the line of sight." The inspector reviewed the changes and found them to be acceptable. This item is closed.

c. (Closed) Violation 50-397/92-43-02, Failure to Repair Containment Isolation Valves As Required By Technical Specifications

Inspection Report 92-43, issued March 22, 1993, included a violation concerning the licensee's failure to repair drywell purge exhaust valve leakage during the first cold shutdown following the discovery of the leakage. This event was the subject of Licensee Event Report (LER) 93-05, dated March 4, 1993.

The licensee responded to the violation in a letter dated April 20, 1993. The response noted that the primary root cause involved the failure of the Shift Manager to fully document the maintenance requirements described within the Technical Specifications (TS) on either the TS limiting condition for operations (LCO) status sheet or the PER. To address this deficiency, the licensee counseled the Shift Manager and issued Night Orders that addressed the lessons learned from the event. In addition, the procedure covering LCO status sheets (PPM 1.3.1.D) was revised to require more detailed information. The inspector reviewed the Night Orders and PPM 1.3.1.D and determined that they were acceptable.

The discussion in Inspection Report 92-43 noted that while the violation was licensee-identified, the violation was issued because the licensee had not addressed the weaknesses involving the failure of management to identify this TS violation. Opportunities to identify this violation included the reviews performed by the Management Review Committee (MRC), which reviews all PERs, and the Plant Operations Committee (POC), which reviews PERs prior to restart. The licensee addressed this concern in their response and observed that in addition to the POC and MRC, the Operations Work Control Coordinator should have identified this deficiency.

The licensee revised PPM 1.16.6, "Scheduling and Coordination of Plant Work," to clearly identify the Work Control Shift Manager's responsibilities for being cognizant of plant configuration, work scheduling, and TS compliance. The inspector reviewed the procedure

change and discussed the changes with the Work Control Shift Manager. The inspector found the procedure changes to be acceptable.

The licensee stated that PPM 1.3.12, the procedure covering PERs, had been revised to strengthen the MRC process by placing greater review responsibility on the department responsible for the problem cited in the PER. A review of these revisions will be conducted in conjunction with Followup Item 50-397/93-24-01 (see paragraph 3.g).

The licensee noted in their April 20, 1993, letter that this event had been included in the "Management Time Out" conducted in mid-February, and that had been included in a consultant's study of the January 1993 forced outage. The licensee committed to have the lessons learned from the "Management Time Out" and the consultant's study incorporated into necessary procedures by October 1993. The inspector reviewed the results of the "Management Time Out" and the consultant's study and found that they included in-depth analysis covering a wide range of issues and several recommended improvements. Many of the recommendations had already been incorporated or were included as committed improvements in the licensee's May 27, 1993, response to the Systematic Assessment of Licensee Performance (SALP).

This item is closed based on the review performed by the inspector and the commitments included in both the April 20, 1993 violation response and the May 27, 1993 SALP response. In addition, the review of LER 93-05 is complete and that LER is closed.

d. <u>(Closed) Violation 50-397/93-08-02, Untimely Corrective Actions for Quality Finding Report Concerning Problem Event Report Initiation</u>

Inspection Report 93-08 identified a violation concerning the licensee's failure to take timely corrective actions to resolve the plant staff's reluctance to initiate PERs. In May 1992, the licensee's Quality Assurance (QA) organization initiated a Quality Finding Report (QFR) identifying nine instances wherein plant staff had failed to initiate PERs for plant problems. In February 1993, the inspector found that the corrective actions identified in the QFR had not been completed and that there had been repeat instances in which PERs were not initiated for plant problems. The licensee responded to the violation in a letter dated April 30, 1993.

The licensee's letter noted two causes for this problem: (1) There was inadequate sensitivity to QA findings and associated corrective actions, and (2) QA failed to provide proper emphasis on followup and resolution of overdue corrective actions. The licensee committed to three corrective actions:

- Licensee supervisory personnel performance plans would include specific goals regarding quality and timeliness of corrective actions by September 30, 1993.

- The PER procedure, PPM 1.3.12, would be revised to provide a more concise program to deal with conditions adverse to quality.

- QA would develop a plan to improve prioritization, tracking, and followup on corrective actions resulting from QFRs by May 21, 1993.

The first corrective action, regarding revisions to supervisory performance plans, was also stipulated in the licensee's May 27, 1993, response to the SALP report. The plant licensing organization, which tracks the SALP commitments, stated that this action had been completed by June 30, 1993.

Although the second corrective action, regarding PER procedure improvements, had not been completed, it will be reviewed during a future inspection as discussed in paragraph 3.g of this report.

The inspector discussed the third corrective action with the Quality Assessments Manager. He noted that QA had developed the improvement plan discussed in the third corrective action. However, just prior to the inspector's review, the QA organization had discovered during an audit of the Supply System's implementation of commitments to the NRC, that the implementation schedule for the improvement plan had not been met and was not being tracked. QA's failure to track the implementation of the improvement plan was significant since the subject of the violation was QA's failure to follow through on corrective actions. The inspector noted that the Quality Assessments Manager, who had been recently hired by the licensee, recognized the significance of QA's failure to implement their improvement plan. The Quality Assessments Manager had taken swift action to update the implementation schedule and had counselled QA supervisors and staff on the necessity of following through on corrective actions and meeting commitments prior to the inspector's involvement. This item is closed.

e. <u>(Closed) Followup Item 93-08-03, Quality Assurance Escalation of Unresolved Issues</u>

Inspection Report 93-08 identified several inspector concerns regarding the methodology used to escalate the resolution of QA QFRs. QA procedures defined the Management Corrective Action Request (MCAR) as the process by which unresolved QFRs are brought to the attention of the Managing Director. The inspector found that the MCAR process had been ineffective in resolving a longstanding QFR.

The inspector discussed this followup item with the Quality Assessments Manager. The QA organization addressed corrective action program weaknesses and proposed program improvements in the licensee's May 27, 1993 response to the SALP. One action completed on June 30, 1993, was to emphasize the importance of corrective actions by including specific goals for quality and timeliness in

the personnel performance plans for supervisors in the Operations, Engineering, and QA Directorates.

The Quality Assessments Manager noted that one of the corrective action program improvements would be to include all QA findings in the PER process and eliminate the separate QFR program. The escalation process for unresolved QA issues would be captured in both the PER process and the personnel performance plans discussed above. The licensee committed to revise the PER process by August 30, 1993. These revisions will be assessed by followup item 50-397/93-24-01 (see paragraph 3.g). This item is closed.

f. <u>(Closed) Followup Item 92-43-04, Fuel Assembly Channeling Procedure Weaknesses</u>

On February 2, 1993, the inspector witnessed the installation and torquing of the channel fasteners on new fuel. The inspector noted that the two procedures used to perform the work (PPMs 6.2.3, "New Fuel Handling on the Refueling Floor," and 6.3.9, "Channeling and Dechanneling Irradiated Fuel") had minor inconsistencies and included duplicate step signoffs. The licensee committed to address these weaknesses.

The inspector reviewed the actions taken by the licensee to resolve this problem. The licensee made revisions to PPM 6.3.9 to allow it to be performed without the use of PPM 6.2.3. The procedure was also revised to include the channel fastener torque values and require that the torque wrench and its calibration date be logged in the data sheet. The inspector found these actions to be acceptable. This item is closed.

g. <u>(Open) Followup Item 50-397/93-24-01, Problem Identification and Resolution Program Improvements</u>

Several of the open items in this report were closed contingent upon a review of commitments made by the licensee to make improvements to the problem identification and resolution program. These open items were:

- NOV 92-43-01, Four examples of procedure violations

- NOV 92-43-02, Failure to repair containment isolation valves as required by Technical Specifications

- NOV 93-08-02, Untimely corrective actions for QFR concerning PER initiation

- Followup Item 93-08-03, QA Escalation of unresolved issues

On May 27, 1993, in their response to the SALP report, the licensee made several additional commitments to revise their corrective action program. A July 29, 1993, letter from the licensee advised the NRC of changes made to the corrective action program improvement schedule. The letter listed 18 separate commitments the licensee

has made to improve the corrective action program. In the letter, the licensee committed to have an improved corrective action program implemented by October 4, 1993. The completion of the licensee's commitments to revise the corrective action program, as discussed above, will be tracked as Followup Item 50-397/93-24-01.

4. <u>Operational Safety Verification (71707)</u>

a. <u>Plant Tours</u>

The inspectors toured the following plant areas :

- Reactor Building
- Control Room
- Diesel Generator Building
- Radwaste Building
- Service Water Buildings
- Technical Support Center
- Turbine Generator Building
- Yard Area and Perimeter

b. The inspectors observed the following items during the tours:

(1) <u>Operating Logs and Records</u>. The inspectors reviewed records against Technical Specifications (TS) and administrative control procedure requirements.

(2) <u>Monitoring Instrumentation</u>. The inspectors observed process instruments for correlation between channels and for conformance with TS requirements.

(3) <u>Shift Manning</u>. The inspectors observed control room and shift manning for conformance with 10 CFR 50.54.(k), TS, and administrative procedures. The inspectors also observed the attentiveness of the operators in the execution of their duties and the control room was observed to be free of distractions such as non-work related radios and reading materials.

(4) <u>Equipment Lineups</u>. The inspectors verified valves and electrical breakers to be in the position or condition required by TS and administrative procedures for the applicable plant mode. This verification included routine control board indication reviews and conduct of partial system lineups. TS limiting conditions for operation were verified by direct observation.

(5) <u>Equipment Tagging</u>. Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and the equipment was in the condition specified.

(6) <u>General Plant Equipment Conditions</u>. Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that would prevent the system from

fulfilling its functional requirements. Annunciators were observed to ascertain their status and operability.

(7) Fire Protection. The inspectors observed fire fighting equipment and controls for conformance with administrative procedures.

Following the repair work done on residual heat removal (RHR) pump A on July 17 (discussed in Paragraph 4.c of this report), the inspector toured the RHR A pump room on July 19, 1993. This tour was conducted to determine if the pump's oil leak had been repaired and if the work area had been returned to an acceptable state of cleanliness following maintenance. The inspector found a five-gallon bucket of lubricating oil on the floor in the pump room. No personnel were in the vicinity of the pump room, and a "Transient Combustible Permit" was not present. The inspector contacted the Shift Manager, who initiated action to remove the combustible material and investigate the cause. The licensee initiated problem evaluation request (PER) 293-993 to address this issue. Licensee investigation revealed that the bucket of oil had been in the area for approximately 48 hours, having been left there by the maintenance personnel performing the repair work on the RHR A pump sightglass.

WNP-2 Plant Procedures Manual (PPM) 1.3.10, "Fire Protection Program," states in Paragraph 6.3.5.a, "...combustible liquids must be removed and put into storage at the end of the job or at the end of the shift if the job is not continuous between consecutive shifts." Paragraph 6.3.8.a of PPM 1.3.10 states, in part, "...when removal is not possible, a Transient Combustible Permit is required if the combustibles are to be left unattended for any length of time (i.e. breaks, lunch)." Further, TS 6.8.1.g states that written procedures are to be implemented for the fire protection program. The condition that existed on July 19, 1993, did not appear to meet these requirements.

Further investigation revealed added significance for this problem. The RHR A pump room was on the hourly fire tour. Approximately 48 fire tours by three different individuals were conducted in the RHR A pump room while the combustible material was present prior to the inspector entering the area. The licensee stated that it was their expectation that the fire watches not only monitor for fires, but for the existence of unattended combustible material. During a recent enforcement conference discussing the issues of missed hourly fire tours, Supply System management stated that they had recently communicated in a clear manner their full expectations for conducting fire tours. The inspector's observation discussed in this section indicates that more effort may be necessary in this area. This failure to follow procedures is an apparent violation of TS 6.8.1.g (Apparent Violation 50-397/93-24-02).

(8) Plant Chemistry. The inspectors reviewed chemical analyses and trend results for conformance with TS and administrative control procedures.

(9) Radiation Protection Controls. The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors also observed compliance with Radiation Work Permits, proper wearing of protective equipment and personnel monitoring devices, and personnel frisking practices. Radiation monitoring equipment was frequently monitored to verify operability and adherence to calibration frequency.

(10) Plant Housekeeping. The inspectors observed plant conditions and material/equipment storage to determine the general state of cleanliness and housekeeping. Housekeeping in the radiologically controlled area was evaluated with respect to controlling the spread of surface and airborne contamination. Housekeeping in the plant appeared to remain in good condition.

On July 22, 1993, during a tour of the area above the low pressure core spray (LPCS) pump, the inspector noted that a ladder had been leaned against an LPCS instrument line and appeared to be unattended. The inspector placed the ladder on the floor away from safety equipment and informed the shift manager. The inspector discussed this with the Plant Manager. The Plant Manager noted that he had observed similar problems on his plant tour and committed to address this issue with plant staff.

(11) Security. The inspectors periodically observed security practices to ascertain that the licensee's implementation of the security plan was in accordance with site procedures, that the search equipment at the access control points was operational, that the vital area portals were kept locked and alarmed, and that personnel allowed access to the protected area were badged and monitored and the monitoring equipment was functional.

c. Engineered Safety Features (ESF) Walkdown

The inspectors walked down selected ESF (and systems important to safety) to confirm that the systems were aligned in accordance with plant procedures. During the walkdown of the systems, items such as hangers, supports, electrical power supplies, cabinets, and cables were inspected to determine that they were operable and in a condition to perform their required functions. Proper lubrication and cooling of major components were also observed for adequacy. The inspectors also verified that certain system valves were in the required position by both local and remote position indication, as applicable.

The inspectors walked down accessible portions of the following systems on the indicated dates:

System	Dates
Diesel Generator Systems, Divisions 1, 2, and 3.	June 24, July 28
Hydrogen Recombiners	June 24, July 29
Low Pressure Coolant Injection (LPCI) Trains A, B, and C	July 13
Low Pressure Core Spray (LPCS)	June 24, July 12
High Pressure Core Spray (HPCS)	July 12
Reactor Core Isolation Cooling (RCIC)	June 24, July 12
Residual Heat Removal (RHR), Trains A and B	July 13, 19
Scram Discharge Volume System	June 24
Standby Gas Treatment (SGT) System	June 24
Standby Liquid Control (SLC) System	June 24
Standby Service Water System	July 20
125V DC Electrical Distribution, Divisions 1 and 2	June 25, July 19
250V DC Electrical Distribution	June 25, July 19

During a tour of the RHR A pump room on July 13, 1993, the inspector noted that the RHR A pump was leaking oil, with oil dripping all around the motor section of the pump from the top down. The inspector contacted the System Engineer (SE). The SE stated that he was aware of the leak and efforts were being undertaken by non-destructive examination (NDE) methods to determine the source of the leak. On July 14, 1993, NDE determined that the oil leak was coming from the upper bearing oil reservoir sight glass. Plant technical personnel determined that the leak was sufficiently small such that they could keep up with the leak with oil additions. The inspector questioned this line of reasoning because the design basis for the RHR A pump is that the pump must run continuously for six months post-accident. The licensee's safety analysis also assumes that the reactor building would not be accessible following an accident. Therefore, the inspector asked the licensee whether an operability determination had been completed for the RHR pump, given the actual design basis for the pump.

As a direct result of the inspector's inquiry, the licensee performed an operability determination for the RHR A pump. The licensee contacted the vendor to aid in the process. The licensee determined that due to the small size of the oil leak [approximately 3 milliliters (ml) per hour] and the large capacity of the oil reservoir, the pump could operate for approximately 12 months without oil addition and no damage to the pump. Based on this information, the licensee considered scheduling repair of the pump at least a month later. The inspector questioned some of the logic in the operability determination. First, the inspector noted that the pump's leak rate was based on static conditions, and that when the pump was running, the leak may be larger because of possible pressurizing of the oil. In addition, the operability determination did not recognize the possibility that the size of the leak could increase over several weeks of operation. Therefore the inspector questioned the licensee's conclusions regarding the pump's repair schedule.

On July 16, 1993, (following the above discussions with the inspector) the licensee performed a 12-hour run of the RHR A pump. The licensee found that the leak rate was approximately 10 ml per hour with the pump in operation (approximately three times the static leakrate). However, the licensee determined that this leak rate was also bounded by the previous operability determination. Nevertheless, the licensee repaired the leak on July 17, 1993.

Although the licensee appeared to be responsive to the inspector's concerns, this event indicated that the systems engineering problem solving methodology may need some improvement. The inspectors will continue to monitor the performance of the system engineers in the future.

One apparent violation was identified.

5. Surveillance Testing (61702, 61705, 61706, 61707, 61726)

The inspectors reviewed surveillance tests required to be performed by the Technical Specifications (TS) on a sampling basis to verify that: (1) a technically adequate procedure existed for performance of the surveillance tests; (2) the surveillance tests had been performed at the frequency specified in the TS and in accordance with the TS surveillance requirements; and (3) test results satisfied acceptance criteria or were properly dispositioned.

The inspectors observed portions of the following surveillance on the date shown:

Procedure	Description	Dates Performed
PPM 7.3.7.5.8	Drywell and Suppression Pool Air Space Hydrogen and Oxygen Monitors Channel Functional Test	July 26, 1993

In addition, the inspectors performed the following inspection modules during the inspection period to support the surveillance area:

a. <u>Determination of Reactor Shutdown Margin (61707)</u>

During the previous inspection period the inspector noted several concerns associated with the licensee's procedure for determining reactor shutdown margin. These were identified as Followup Item 50-397/93-18-08. The inspector resolved these issues as follows:

(1) The nuclear engineer performing the test appeared to have used an incorrect value for the effective neutron multiplication factor (keff) for all rods in. Because shutdown margin is defined as the margin to criticality with the strongest rod out, Plant Procedures Manual (PPM) 7.4.1.1, "Reactor Shutdown Margin and/or Demonstration," required the user to calculate the worth of the strongest rod by subtracting the predicted keff for all rods in from the predicted keff for the strongest rod out, based on data provided in the Startup Operations Letter Report (SOLR). The SOLR did not provide a value for keff with the strongest rod out, but provided two values for keff with all rods in (i.e. one for 68°F and one for 180°F). PPM 7.4.1.1 did not provide direction to the user as to which of these two values should be used in the rod worth calculation. PPM 7.4.1.1 also did not provide direction on how to determine keff for the strongest rod out. The SOLR did provide a value for predicted shutdown margin at 68°F.

Using the above information the inspector calculated the worth of the strongest rod. The inspector assumed that the value for keff with the strongest rod out equaled one minus the predicted shutdown margin at 68°F. Since this value was calculated at 68°F, the inspector used the value provided for 68°F for the value of keff with all rods in. However, the licensee nuclear engineer performing the surveillance calculated the worth of the strongest rod using the values for predicted shutdown margin at 68°F, and predicted keff all rods in at 180°F, which did not appear to be a consistent use of units. The reactor engineering supervisor discussed this issue with the vendor and determined that the inspector's observation was correct.

(2) The completed copy of PPM 7.4.1.1 provided to the inspector one week after performance had apparently not been reviewed by the operators, the Shift Manager, or the assigned reviewer. The Nuclear Engineering Supervisor stated that he was normally the assigned reviewer but could not recall whether or not the procedure had been reviewed. Although PPM 7.4.1.1 had been performed on June 21, 1993, the Reactor Engineering Supervisor did not perform a detailed technical review of the completed copy of PPM 7.4.1.1 until July 12, 1993. The inspector expressed concern that TS surveillance procedures should be expeditiously reviewed to ensure that operability problems do not arise.

(3) The licensee performer of the surveillance appeared not to have interpolated group 3 rod worth for temperature as required by PPM 7.4.1.1.

(4) The cover page of PPM 7.4.1.1 referenced American Society of Mechanical Engineers (ASME) Section XI ("Rules for Inservice Inspection of Nuclear Power Plant Components") in the title section. The proper reference appeared to be the reactivity control systems section of the TS.

(5) As a result of the inspector's concerns above, the licensee contacted the vendor for additional guidance on the proper performance of shutdown margin calculations. As a result of this inquiry, the licensee also determined that they had been using the incorrect value for moderator temperature coefficient (MTC). The SOLR provides MTC values for predicted critical and all rods in, and PPM 7.4.1.1 does not provide direction on which value to pick. The correct value for MTC was the MTC for all rods in. When PPM 7.4.1.1 was performed on June 21, 1993, the licensee performer used the value for predicted critical.

After the above issues were identified, the licensee issued problem evaluation request (PER) 293-992 to determine the root causes for the problems and develop corrective actions. The licensee stated in the PER that the root cause of the problems was an "inadequate procedure." The licensee performed reviews of the performance of PPM 7.4.1.1 following the three previous startups from refueling and found that the wrong values had also been used during previous performances. Although the licensee determined that sufficient shutdown margin existed after all corrections were made, this issue emphasized the need for thorough review of procedures prior to issuance. As corrective actions, the licensee committed to revise PPM 7.4.1.1 to clearly state the proper values needed to complete the calculation. In addition, the licensee committed to meet with the vendor to request that future SOLRs provide the desired data in a useable manner.

10 CFR 50, Appendix B, Criterion V requires activities affecting quality to be prescribed in accordance with procedures appropriate to the circumstances. Due to the apparent inadequacies of PPM 7.4.1.1, this procedure did not appear to meet this requirement. This is a violation of 10 CFR 50, Appendix B, Criterion V (Violation 50-397/93-24-03). Followup Item 50-397/93-18-08 is closed.

b. <u>Power Distribution Limits (61702)</u>

The inspector reviewed the licensee's procedures and processes for determining if core thermal limits were within TS limits. WNP-2 PPM 7.4.2.1, "Power Distribution Limits," and the Core Operating Limits Report (COLR) were used as guidance. The inspector found that the thermal limits were within TS and COLR limits, and that these procedures were being performed at the proper intervals.

The inspector also checked the licensee's computer program to determine if the limits prescribed by the COLR for the Cycle 9 core had been entered properly. The inspector saw that the limits in the COLR appeared to be correct for the Siemens Power Corporation (SPC) 8 x 8 and 9 x 9 fuel assemblies in the core. However, the inspector noted a minor discrepancy associated with the Lead Fuel Assemblies (LFAs). The limits loaded into the WNP-2 plant computer did not appear to match the limits listed for the LFAs in the COLR. The inspector discussed this observation with a reactor engineer.

The WNP-2 core includes four General Electric (GE), four SPC, and four Asea-Brown-Boveri (ABB) LFAs. These LFAs have a different number of fuel pins than the rest of the fuel bundles in the core. The Linear Heat Generation Rate (LHGR) limits for these LFAs were generated by taking the LHGR for the SPC 8 x 8s, and multiplying this value by the ratio of the number of fuel pins in an 8 x 8 assembly and the number of fuel pins in the LFA for each particular LFA vendor. Because the limits were developed in this manner, and because the Supply System's plant computer was incapable of modeling the LFAs, the Supply System entered the LHGR limits for the 8 x 8 assemblies for monitoring the LFAs. Due to the fact that the amount of power per pin was less in a 9 x 9 or 10 x 10 LFA assembly, the Supply System reasoned that this was an acceptable practice. The inspector questioned the use of this methodology because none of the correspondence submitted to the NRC concerning thermal limits stated that these methods would be used.

On July 22, 1993, the inspectors participated in a conference call with staff members of the NRC Office of Nuclear Reactor Regulation (NRR). The NRR staff members stated that although the Supply System methodology for monitoring thermal limits for LFAs was previously not recognized by the NRC, this methodology appeared to be satisfactory because the margin to the thermal limits would be the same regardless of computational methods.

The licensee discussed this issue with other Boiling Water Reactor (BWR) licensees and found that WNP-2 was apparently the only BWR utility that calculated their thermal limit margins in the method described above. The inspector noted that the licensee should be very careful when deviating from industry practices, because the experience of other utilities can be useful in solving problems at WNP-2. This issue is closed.

c. Calibration of Local Power Range Monitors (LPRMs) (61705)

The inspector reviewed the licensee's procedures and processes for calibration of the local power range monitors using the traversing in-core probe (TIP). The inspector witnessed portions of the licensee's TIP runs and performed a technical evaluation of the licensee's procedure PPM 9.3.3, "LPRM Calibration." The inspector also reviewed the completed copy of PPM 9.3.3. The inspector determined that the LPRM calibrations were conducted properly and in accordance with the TS and PPM 9.3.3. The completed copy of PPM 9.3.3 appeared to adequately document the results.

d. <u>Core Thermal Power (CTP) Evaluation (61706)</u>

The inspector reviewed the licensee's procedures and processes for determining CTP. The inspector verified that the instruments that provide input to the calculation had been calibrated and were in calibration, and that the shift technical advisors (STAs) and station nuclear engineers (SNEs) were knowledgeable and proficient in these procedures. The inspector also performed a manual CTP calculation using the licensee's procedure. In addition, the inspector performed a detailed technical review of the licensee's methodology. PPM 9.3.1, "Manual Core Heat Balance," was used as guidance.

The licensee has three methods for determining CTP. Each of these methods performs a heat balance by subtracting all heat inputs to the reactor from all heat output from the reactor, then converts this number to megawatts thermal (MWt). The primary method uses the plant performance computer replacement system (PPCRS). The PPCRS calculates CTP approximately every 20 seconds using inputs from the applicable instruments in the control room. In addition, PPCRS calculates a running average CTP for one minute, 15 minute, one hour, four hour, and eight hour intervals, so that the licensee can monitor if the CTP exceeded the licensed CTP level of 3323 Mwt over any of these intervals. The second method (preferred backup) uses a personal computer (PC) with manual input of the data to perform the heat balance. The third method for performing the heat balance is to hand calculate CTP using PPM 9.3.1.

The inspector calculated CTP on July 16, 1993, using PPM 9.3.1. The value obtained by the inspector closely correlated (within 2%) with the PPCRS values for that time period. In addition, the STA and SNE demonstrated proficiency in using the PC to calculate CTP.

The inspector reviewed PPM 9.3.1 to determine the technical adequacy of the procedure. PPM 9.3.1 allows the user to either read the data inputs from the control room panels, or obtain the data from the computer points being input to PPCRS. The inspector noted that a difference existed between the calculation using the computer points versus inputting the data values from the panels. The control room panel instrument for calculating reactor water cleanup (RWCU) flow displays the full system flow at the suction of the RWCU pumps. However, to use the computer points, the user is required to sum the individual flows through each of the RWCU demineralizers to determine total system flow. When performing calculations using each of these methods, the inspector found a significant difference in the two flow rates. The indicated total RWCU flow on the control room panels was 495 gallons per minute (gpm), while the sum of the individual RWCU demineralizer flows was 180 gpm. Using two different values for RWCU flow resulted in different values for the amount of heat rejected through the RWCU system. The inspector calculated a 4 Mwt difference in total CTP using the two different data input methods.

The inspector questioned the SNE on the difference in total RWCU flow. The SNE stated that the difference was probably due to temperature compensation done by the computer. The inspector questioned this answer because it did not appear that temperature compensation would result in nearly a factor of three difference in flow rates. Further investigation by the inspector revealed that the flow difference could be partially explained by the fact that the RWCU system was aligned such that one of the RWCU demineralizers was bypassed, and the bypass flow was not accounted for in the computer points. In addition, as a result of the inspector's concern, the licensee evaluated the temperature compensation done by the computer and found that it was done improperly. Thus, these two discrepancies accounted for the differences in RWCU total flow rate. Therefore, if the licensee used the computer points as input for RCWU flow rate during a period of time when one of the RWCU demins was bypassed, it appeared that the CTP calculation would be inaccurate by 4 Mwt in the non-conservative direction. The condition of the non-conservative temperature compensation error coupled with a RWCU demin in bypass existed during the inspector's observation on July 16, 1993.

The inspector also determined that the PPCRS computer uses the sum of the flows through the RWCU demins in determining CTP. Licensee records indicated that on numerous occasions the eight-hour average of reactor power (as calculated by the PPCRS) was either 3322 or 3323 Mwt. Therefore, with the non-conservative contribution to CTP from RWCU flow, it appeared that the licensee may have exceeded the facility's licensed thermal power value for greater than eight hours on numerous occasions. Paragraph C.(1), "Maximum Power Level," of the WNP-2 operating license states, "The licensee is authorized to operate the facility at reactor core power levels not in excess of 3323 Mwt..." The NRC interprets this license requirement to mean that the average power level over any eight-hour period shall not exceed the full license power level. However, minor and temporary incursions above 100% (not to exceed 102%) are allowed as long as an eight-hour average restriction is followed. This interpretation was promulgated to all power reactor licensees in an NRC letter dated August 22, 1980. The Supply System keeps a copy of this letter in the control room.

The licensee evaluated the above observations for reportability and determined the above non-conservatism in calculating CTP to be non-reportable based on other conservatism found in the calculation. The licensee found that conservatism in calculating heat input from the control rod drive system, in empirically calculating enthalpies, and in instrument inaccuracy made up for the inaccuracies due to improper temperature compensation. The licensee also determined that, except for a three day period, the RWCU demins were bypassed for periods no longer than 2 hours during any eight-hour period. During the three day period, the licensee did not exceed a calculated power level of 3319 Mwt averaged over any eight hour period. Therefore, the licensee did not exceed the licensed power level for greater than eight hours.

The licensee wrote PER 293-0994 to address the above concerns. As immediate corrective actions, the licensee restricted the eight-hour

average of CTP to 3320 Mwt until the temperature compensation error in the PPCRS program was corrected. On July 22, 1993, the temperature compensation error in the RWCU flow was corrected in the PPCRS. In addition, the licensee issued a night order restricting the eight-hour average of CTP to 3317 Mwt when one of the RWCU demins is bypassed. PPM 2.2.3, "Reactor Water Cleanup System Operations," was changed to include a precaution to limit the eight-hour average of CTP to 3317 Mwt when removing an RWCU demin from service. For longer term corrective action the licensee intends to change the computer input for RWCU flow, from the sum of the flow through the demins, to total system flow at the suction of the RWCU pumps.

The concerns addressed, associated with the incorrect calculation of CTP appear to have minimal safety significance. Table 15.0-2 of the Final Safety Analysis Report (FSAR) states that the safety analyses for WNP-2 were based on 3464 Mwt (104.3% power); therefore, exceeding the licensed full reactor power level by 4 MWt did not appear to have an effect on the consequences of an accident. However, these issues indicated that less than thorough reviews of PPM 9.3.1 and the inputs to the PPCRS were conducted.

Because PPM 9.3.1 allowed the user to determine the contribution to the CTP calculation from the RWCU system in a non-conservative method, PPM 9.3.1 appeared to be inadequate. This is an example of inadequate procedures, in violation of 10 CFR 50, Appendix B, Criterion V (Violation 50-397/93-24-04).

The problems found by the inspector indicated that the level of attention to detail among the nuclear/reactor engineering staff required improvement. Following the inspector's observations, the licensee initiated action to have the reactor engineering staff review their procedures to ensure they are technically adequate. In addition, the operations shift engineers committed to provide an independent review of these procedures.

One violation was identified.

6. Plant Maintenance (62703)

During the inspection period, the inspector observed and reviewed documentation associated with maintenance and problem investigation activities to verify compliance with regulatory requirements and with administrative and maintenance procedures, required Quality Assurance/Quality Control (QA/QC) involvement, proper use of clearance tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. The inspector verified that reportability for these maintenance activities was correct.

The inspector witnessed portions of the following maintenance activities:

Description	Dates Performed
AP4091, Refueling Mast Replacement	July 12-13
AP4371, Repair Actuation Switches for Containment Vacuum Breakers	July 15
AP4749, Trouble Shoot and Repair E-TR-7BC, (Voltage Regulator)	July 27
AP4367, Fabricate and Install Seismic Supports for the Control Rod Drive (CRD) to RPV Level Instrument Purge	July 28-30
AP4368, Fabricate and Install Valves for the CRD to RPV Level Purge	July 28-30

No violations or deviations were identified.

7. Plant Startup from Refueling (61703)

The inspectors reviewed the licensee's procedures, conducted interviews with selected licensee and contractor personnel, and witnessed portions of the licensee's initial startup from refueling outage R8. The inspector used Plant Procedures Manual (PPM) procedures 3.1.1, "Master Startup Checklist," and 3.1.2, "Reactor Plant Cold Startup," for guidance. Plant startup from refueling was in progress at the beginning of this inspection period, with the reactor at 20% power.

The inspectors performed an independent spot check of selected prerequisites which had been signed as completed in PPM 3.1.1. With one exception, Temporary Modification Requests (TMRs) (discussed below), the inspectors found that the prerequisites had been met.

The inspectors conducted a thorough walkdown of the reactor coolant system (RCS), the high pressure core spray (HPCS) system, and the primary containment (drywell). The inspectors also reviewed outstanding maintenance requests and design changes associated with these systems. The inspectors concluded that the material condition of these systems was adequate for restart.

The inspectors witnessed selected portions of the WNP-2 startup following R8. The inspectors verified that the licensee conducted the startup using preapproved procedures and preapproved control rod withdrawal sequences, and was in accordance with Technical Specifications (TS). The completion of the power escalation sequence of the reactor startup appeared to have been conducted in a conservative and deliberate manner with little or no problems. The inspectors will continue to monitor the performance of operators during power maneuvers during future inspections.

Review of Temporary Modification Request (TMR) Log

On June 30, 1993, after the reactor was in Mode 1 and at 100% power, the inspector reviewed the TMR log in the control room to determine if the TMR log had been cleared of outage-related temporary modifications and was up to date. The inspector found that TMR-93-017 (that installed temporary leads associated with the scram discharge volume) appeared to be in effect when it was required to be removed prior to plant startup. The "operational restrictions" section of the TMR states, "Remove test leads following completion of surveillances ... and prior to Mode 1 or Mode 2." In addition, the justification for the TMR in the attached 50.59 evaluation stated that the TMR had no impact on plant operation because the leads would only be installed while the plant was shutdown.

Despite all of the precautions in TMR-93-017 to ensure that the TMR was cleared, the TMR was in the "active" section of the TMR log and all of the signatures for installation of the TMR were present. All of the signatures for restoration of the TMR and clearance of the TMR tags were not complete.

Upon this observation, the inspector notified the Shift Manager (SM) of the discrepancy in the TMR log. The SM agreed with the inspector's observation that the TMR should not be installed during power operation. The SM stated that he expected the System Engineer (SE) to ensure the TMR was restored. The SM contacted the SE and the SE stated that the hardware associated with the TMR was actually removed prior to startup, and he expected the electrical shop to update the paperwork in the TMR log. After the inspector questioned the Technical Manager on the performance of the SE in this event, the Technical Manager stated the SM was responsible for updating the TMR log. Following these discussions with the inspector, the licensee removed the TMR tags, signed off for restoration of TMR-93-017, and removed this TMR from the active section.

Although the hardware associated with TMR-93-017 had in fact been removed prior to plant startup, several procedure steps in clearing a TMR were not followed. WNP-2 PPM 1.3.9, "Temporary Modification Requests," states in Paragraph 6.3, "Restoration of a TM via a TMR:"

"6.3.6 Upon authorization from the Shift Manager, the Work Supervisor, or designee shall:

c. Account for all TMR tags. Return all the TMR tags to the control room. Tags that cannot be returned because they are lost or contaminated shall be noted in the TMR form comments section.

d. Ensure the individuals performing the removal sign the Restoration performed by and Verified by steps on the original TMR form.

e. Inform the shift manager the TM has been removed...

6.3.7 The Shift Manager shall:

a. Review the original TMR form to ensure all the TMR tags are accounted for, returned tags are discarded, and all the required steps are signed.

c. Ensure any restoration testing specified in the TMR is complete.

d. Ensure documents changed and/or special instructions issued... are corrected and operating personnel on shift have been briefed.

e. Sign the Restoration Complete and note any unexpected, or unusual events in the comments section...

f. File the TMR in the Completed section of the TMR log.

g. Make the appropriate date entry in the TMR Log index under Restored Date."

The conditions that existed on June 30, 1993, indicated that none of the procedure steps of paragraphs 6.3.6 and 6.3.7 had been followed when the TMR was removed on June 20, 1993. Although the safety significance appeared to be minor because the hardware had already been removed, it appeared that operations personnel were unaware of the status of a safety system (the scram discharge volume). The failure to follow PPM 1.3.9 is an apparent violation of 10 CFR 50 Appendix B, Criterion V (Apparent Violation 50-397/93-24-05).

The inspector discussed the above observations with the Plant Manager. The inspector noted that teamwork and accountability among Operations, Engineering and Maintenance appeared to require improvement in this instance.

The inspector was also concerned that the PPM 1.1.7, "Restart Evaluation Process," requires the Technical Services Manager to review the TMR log for acceptability prior to plant startup. The Technical Services Manager based his approval of this restart item on input from the system engineers. Paragraph 7.4.1 of PPM 1.3.9 requires the Shift Manager and the Control Room Supervisor to review the TMR log once a shift. Paragraph 7.4.3 of PPM 1.3.9 requires the Operations Manager (or designee) to review the TMR log prior to plant restart. Furthermore, Paragraph 7.4.4 of PPM 1.3.9 requires the Operations Manager (or designee) to review the TMR log at least weekly. The inspector questioned the licensee regarding whether all of these reviews had been thorough and probing. The Plant Manager acknowledged the inspector's comments.

One apparent violation was identified.

8. Licensee Event Report (LER) Followup (90712, 92700)

a. (Closed) LER 50-397/92-37, Revisions 0, 1, and 2, "Manual Reactor Scram Due to Core Instability"

The inspector performed an in-office review of LER 92-37, Revisions 0, 1 and 2, "Manual Reactor Scram Due To Core Instability," which was associated with operating events. The event described in this LER was the subject of an Augmented Inspection Team (AIT) and an escalated enforcement action for which a civil penalty was assessed. Based on these reviews and the information provided in the report, the inspectors concluded that reporting requirements had been met, the root causes had been identified, and corrective actions were appropriate. This LER is considered closed.

b. (Closed) LER 50-397/89-01, Revisions 0, 1, 2, "Unanalyzed Failure Modes for Containment Nitrogen System Caused By Inadequate Design Procedures"

On January 12, 1989, the licensee identified four previously unanalyzed failure modes of the non safety-related containment nitrogen (CN) inerting system which could impact the performance of safety-related equipment. The licensee determined that these failure modes had resulted due to an inadequate design review, as a result of inadequate design procedures, when the liquid nitrogen storage tank was installed.

The first two failure modes, system isolation failures, could have resulted in liquid nitrogen progressing into portions of the system piping not designed for low temperatures. Subsequent piping failures could have exposed safety-related equipment to liquid nitrogen. The third and fourth failure modes involved failures of the CN liquid nitrogen storage tank, possibly starving the emergency diesel generators of oxygen. The licensee included the summary of an analysis of the impacts of a CN storage tank failure in a November 14, 1991, revision to the LER. An analysis included in this revision determined that the consequences of a failure of the CN storage tank were within the bounds of the design basis and that further actions to address the third and fourth failure modes were not necessary.

To address the first two failure modes, the licensee installed safety-related temperature-controlled isolation valves on both the "high flow", drywell inerting line and the "low flow", normal nitrogen supply line. However, the inspector performed a walkdown of the system and noted that a temporary modification had been performed on the automatic isolation valves for the high flow line. The temporary modification essentially disabled the automatic isolation valves and was performed because of problems the licensee had experienced with the valves. The inspector noted the following during the walkdown:

- The inspector used a licensee piping and instrumentation drawing (P&ID, M783, Revision 33) copied from the licensee's microfilm file to perform the walkdown. The inspector verified that the drawing revision number matched the drawing used in the work control center and the control room. The inspector found that the microfilm drawing did not reflect the temporary modification. However, the drawings in the work control center and the control room did show the temporary modification. The inspector was concerned about the controls in place to ensure plant work is performed using drawings which reflect the correct plant configuration.

- The inspector questioned whether the manual valves in series with the high flow line should be locked closed. The inspector noted that the normally closed bypass line for the low flow nitrogen line was isolated by a locked closed manual valve. While the high flow line did not have a similar bypass line, the temporary modification had disabled the automatic valves in the open position. The inspector questioned whether, if the low flow bypass line was locked to prevent inadvertent operations from affecting safety equipment, then the manual valves in series with the high flow line should be locked closed for similar reasons.

The inspector will follow up these two issues in a future inspection (Followup Item 50-397/93-24-06). The inspector concluded that the licensee's actions as described in the LER were acceptable.

c. <u>(Closed) LER 50-397/91-10, Revisions 0 and 1, "Potential Inability to Isolate Primary Containment Due to Wiring Separation Error Caused by Inadequate Instruction"</u>

On March 8, 1991, the licensee discovered a wiring separation error affecting the containment isolation valves for the reactor recirculation (RRC) flow control valve hydraulic supply (HY lines). It was determined that a "smart short" could prevent the automatic isolation of four 1-inch diameter lines. The licensee determined that this error had occurred during initial plant construction. Revision 1 to the LER noted that the separation errors had been corrected during the 1991 refueling outage when the licensee installed additional fireproofing material. In addition, the licensee reviewed other systems to determine if similar separation problems had occurred.

The inspector reviewed the licensee's 1991 design change documentation. The inspector verified that the use of fireproofing material in lieu of physical separation was allowed for this application by the licensee's construction criteria. The inspector had no findings and this item is closed.

d. <u>(Open) LER 50-397/92-20, "Flow Element for Low Pressure Core Spray (LPCS) Minimum Flow Control Not Properly Installed"</u>

On May 5, 1992, the licensee determined that a flow element in the LPCS system, LPCS-FE-002, had not been installed properly. The improper installation had allowed air to be entrained in the sensing lines during LPCS pump operation, giving an erroneously high reading which could have resulted in the premature closing or the failure to open of the minimum flow valve.

The sensing lines for flow element LPCS-FE-002 provide inputs for flow switch LPCS-FIS-4, which is designed to actuate to close the minimum flow valve when LPCS flow is greater that 770 gpm. Between December 1991, and April 1992, the licensee noted several instances in which the LPCS-FIS-4 read on-scale while the system was shut down. This offset could have caused the minimum flow valve to close when LPCS flow was less than 770 gpm. The licensee discovered in their review that the instrument sensing lines were connected to the top of the pipe, not the side as specified by the vendor manual for LPCS-FIS-4. The error had been made during plant construction.

The inspector reviewed the licensee's corrective actions, assessment of applicability to similar instruments, and assessment of safety significance.

The licensee committed in the LER 92-20 to correctly install the instrument lines in the 1992 refueling outage. The inspector verified that the modification had been completed and that LPCS-FIS-4 did not indicate flow with the LPCS pump shut down.

The licensee also committed to perform a walkdown of ECCS systems to determine the orientation of flow sensing lines. The licensee discovered that the instrument lines for HPCS-FE-7, which performs the same function for the high pressure core spray system as LPCS-FE-002 provides for the LPCS system, were connected to the top of the pipe. The licensee concluded that this arrangement was satisfactory since there were no previous equipment operability concerns.

The inspector noted during a walkdown that HPCS-FIS-6, which receives its input from HPCS-FE-7, read between 50 and 75 gpm with the pump shut down. The inspector asked the system engineer what the maximum allowable offset was from zero. The system engineer stated that the calibration procedure allowed ± 214 gpm when there was no HPCS flow and ± 18 gpm at the switch setpoint of 1306 gpm. The difference in error band was a result of the non-linear response of the instrument to the differential pressure input. Based on this information, the inspector's observation appeared to be acceptable.

LER 92-20 noted that the problem with LPCS-FIS-4 may have gone undetected because the instrument was isolated from service during calibration and functional testing. However, the corrective actions described in the LER did not address this weakness. The system engineer noted that while he checked the instruments during his rounds, this was not required. In addition, verification of these instruments was not included in operator rounds. The inspector was concerned that corrective actions may not be sufficient to detect future instrument offset problems.

The inspector also reviewed the safety assessment contained in LER 92-20. While the LER noted that the LPCS-FIS-4 read greater than zero with the LPCS pump in standby, it did not state what the maximum offset observed had been. Furthermore, the safety assessment implied that offset was less than the instrument setpoint. The inspector asked the system engineer what the greatest offset was which had been observed. The system engineer noted that on April 18, 1992, as documented in MWR AR 8394, LPCS-FIS-4 had been observed to read 800 gpm. The system engineer, who was not involved with the review, did not know if the switch, which should be set between 770 gpm and 900 gpm as required by the TS, had in fact actuated. The inspector was concerned that the licensee's safety assessment did not fully review the consequences of this problem.

The inspector will review the corrective actions to detect future instrument errors and the adequacy of the licensee's safety assessment in a future inspection.

No violations or deviations were identified.

9. Followup of Events (71707, 92701)

a. Control Rod Positioning

On June 22, 1993, at approximately 9:44 p.m., while withdrawing control rods to 24% power, the shift technical advisor (STA) directed the reactor operator (RO) to move control rod 22-55 from position 00 to 08. However, that control rod had been previously moved to position 08. The Shift Manager (SM) suspended rod movement to resolve this discrepancy in the rod pull-sheet. At 9:52 p.m., the SM documented the event in his log as follows: "Notified by the Shift Nuclear Engineer (SNE) that a procedural problem occurred during control rod movement to maintain reactor power less than 25%." The SNE also initiated Problem Evaluation Request (PER) 293-922 to document the event. In the PER the SNE described the event as follows: "Control rod 38-55 was inadvertently skipped while power was being maintained at 24%. The rod worth minimizer (RWM) order should have been maintained up and down RWM steps, but due to a missed signature the rod was left at position 00. The misposition was found prior to leaving the RWM group and is not a safety issue."

The SNE, STA and SM investigated the event and determined that no safety issue existed. At approximately 10:10 p.m., the SM discussed the event with the Operations Manager (OM), who agreed that no safety issue existed. The OM and SM determined that resumption of control rod withdrawal was acceptable.

On June 24, 1993, during the inspector's review of plant logs and PERs, he noted that an event associated with control rod positioning had occurred. Due to the lack of detail in the SM's log and the description of the event in the PER, it appeared that control rods had been moved out-of-sequence. This was of concern since the licensee, in response to the power oscillation event of August 1992, had implemented corrective actions to prevent control rod positioning errors.

The inspector discussed the event in a meeting with the Operations Division Manager (ODM), the OM, the SM and the STA. Collectively, these Supply System personnel believed that control rods had been moved out-of-sequence, due to the STA's initialing that control rod 38-55 had been moved instead of control rod 22-55.

Upon further review of the control rod pull sheet, the PER, control rod profiles and discussion with the STA, the inspector concluded that control rods had more than likely not been pulled out of sequence. The sequence of events appeared to indicate that the STA had directed the RO to move control rod 22-55, the RO moved control rod 22-55, and that the STA then inadvertently initialed that control rod 38-55 had been pulled. Control rod movement was temporarily discontinued at that point to stabilize reactor power. Then, when control rod movement was resumed following power stabilization, the STA directed the next uninitialed control rod in the sequence to be moved; however, that rod was already in the position to which it was to be moved. At that point the SM suspended rod movement to fully understand the sequence of events.

The inspector requested that the licensee reassess the event. Upon further evaluation, the licensee confirmed the inspector's understanding of the event. To prevent recurrence of the event, the licensee now requires both the RO and the STA to initial each control rod movement. The licensee counselled the individuals involved with the event.

From this event the inspector concluded the following:

- The event had no safety significance, since control rods had not been mispositioned.

- Even though they understood the event had no safety significance, neither the SM nor the OM fully understood the event prior to resuming rod movement.

- The detail of RO and the SM logs was insufficient to describe and reconstruct the event. The RO log did not document the event and the SM log failed to adequately document the problem.

- The licensee had not established adequate administrative controls to assure proper control rod positioning.

- The licensee's corrective actions to assure correct rod positioning were adequate.

The inspector considered management's actions in response to this issue to be appropriate.

b. High Pressure Core Spray (HPCS) Minimum Flow Valve HPCS-V-12

The high pressure core spray system minimum flow valve, HPCS-V-12, is a Quality Class I, 4-inch, Anchor Darling, parallel disk, motor-operated gate valve. The licensee uses a Limitorque Model SMB-0 as

the motor operator for the valve. The minimum flow valve assures adequate cooling flow to the HPCS pump while it is running at shutoff head, and adequate emergency cooling flow when the pump is injecting into the reactor coolant system during accidents.

On June 6, 1993, during motor-operated valve (MOV) testing on HPCS-V-12, the valve failed to fully close due to premature wedging of the parallel disks. To resolve this problem, the licensee increased the torque capability of the valve by replacing the motor pinion gear and worm gear with gears of a different drive ratio. The procurement engineer, who issued the replacement gears as the material verifier, made a cognitive error by not completely reviewing the procurement documents that indicated that the gears were not procured as safety-related. This is an apparent violation of PPM 1.3.52, "Material Verification" (NCV 50-397/93-24-07).

On June 18, 1993, during a review of procurement records, the licensee determined that the motor pinion gear and the worm gear were procured as commercial-grade items, and that the gears did not have a certificate-of-compliance demonstrating acceptable material hardness. The licensee initiated PER 293-901 to document the problem. As corrective actions to prevent event recurrence, the licensee counselled the procurement engineer and changed procurement procedures to require a verification of parts used in safety-related applications. Because the licensee's corrective actions meet the intent of 10 CFR 2, Appendix C, VII. B.(2), the above violation is non-cited.

The licensee had no Class 1 gears in storage; therefore, the licensee evaluated the acceptability of using the commercially procured gears. The evaluation consisted of contacting the gear supplier, performing an engineering evaluation on the commercially procured gears, performing an operability determination, and performing a safety evaluation. The Plant Operating Committee (POC) reviewed these documents and concluded that use of the commercially procured gears was acceptable.

To assess the detail and thoroughness of the licensee's evaluation of the acceptability of the commercially procured gears, the inspector reviewed the POC meeting minutes, the safety evaluation, and the operability determination, and discussed the assessment with members of WNP-2 management.

The inspector noted that the gear supplier stated that there was no difference in the manufacturing of Class 1 and Class 2 gears, except that Class 1 gears were hardness tested. The supplier stated that the Class 1 gears had a hardness requirement of between 55 and 61 on the Rockwell hardness scale. However, when the licensee measured the hardness of the remaining gears that came from the same lot as the gears installed in HPCS-V-12, they found that two of the six gears had a Rockwell hardness of approximately 24 and 31. The inspector noted that the licensee's engineering evaluation used a Rockwell hardness of 24 in analyzing the gears for use in HPCS-V-12. The engineering evaluation concluded that gears with a hardness of

24 would function at least 2000 cycles without failure. The inspector's review of the POC minutes indicated that the POC had concluded that failure of HPCS-V-12 in either the open or closed position would not damage piping and would provide adequate flow, respectively. The POC also concluded that additional information was required from the supplier, but not prior to restart.

From the review of the above documents, the inspector concluded that sufficient data was not available to conclude that the valve could perform its safety function in all accident scenarios. The inspector's conclusion was based on the following:

- The licensee had not performed a commercial-grade dedication, including identifying the gears' critical characteristics and assuring these critical characteristics were acceptable.

- The licensee did not resolve the conflicting information provided by the vendor. While the vendor stated that there was no manufacturing differences between Class 1 and Class 2 gears, hardness testing clearly identified there to be a significant material difference.

- The licensee's engineering evaluation used a hardness of 24 as the lowest hardness value, but did not have sufficient data to conclude that 24 was the lowest possible hardness that the gear could have.

- The licensee established no administrative controls for the operators to limit the number of cycles of HPCS-V-12 before or during an accident.

- The licensee did not resolve the issue that the gear may have been bronze. Even though Engineering used a hardness of 24 in the calculation, there was insufficient objective evidence to support a conclusion that a bronze gear would have a hardness of 24.

The inspector met with members of licensee management and shared his concerns on this issue. As a result, the licensee obtained additional information from the supplier, formally identified the gears' critical characteristics, and performed a commercial-grade dedication using Electric Power Research Institute guidelines. The supplier indicated that gear hardness was measured for all Class 1 gears. If gear hardness was found less than the 55 - 61 criterion, the gears were further heat treated or rejected. The supplier stated that a hardness of 24 was the lowest possible hardness for the commercial-grade gears. The supplier noted that they perform no review to evaluate commercial-grade gears that may be in the same lot with Class 1 gears. Based on the inspectors concerns, the licensee indicated that they plan on replacing the gear or measuring the actual hardness during the next outage. The inspector concluded that with the additional information the supplier provided and the engineering evaluation the licensee performed, the gears appeared acceptable for use in HPCS-V-12 for a limited use of 2000 cycles.

In summary, the licensee issued and installed commercial-grade gears in the motor-operator of a safety-related valve. In reviewing procurement documents the licensee identified the error and implemented corrective actions to prevent event recurrence. The on-site review organization's evaluation of the acceptability of using commercial-grade instead of safety-related in HPCS-V-12 was weak. After the inspectors challenged the adequacy of this evaluation, the licensee obtained additional information to support the use of the nonsafety-related in HPCS-V-12 and performed a commercial-grade dedication.

One non-cited violation was identified.

10. Exit Meeting

The inspectors met with licensee management representatives periodically during the report period to discuss inspection status, and an exit meeting was conducted with the indicated personnel (refer to paragraph 1) on August 6, 1993. The scope of the inspection and the inspectors' findings, as noted in this report, were discussed with and acknowledged by the licensee representatives.

The Startup Operations Letter Report (SOLR), which has been identified as a proprietary document by the licensee, was reviewed by the inspector to support the inspections performed in paragraph 5.a of this report. The licensee did not identify as proprietary any of the information presented in this report as discussed with the inspectors during the exit meeting.