ENCLOSURE 1

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-397
License No.:	NPF-21
Report No.:	50-397/96-24
Licensee:	Washington Public Power Supply System
Facility:	Washington Nuclear Project-2
Location:	Richland, Washington
Dates:	October 27 through December 7, 1996
Inspectors:	R. C. Barr, Senior Resident Inspector G. D. Replogle, Resident Inspector G. M. Good, Reactor Inspector
Approved By:	F. R. Huey, Acting Chief, Reactor Project Branch E Division of Reactor Projects

Attachment: Supplemental Information

EXECUTIVE SUMMARY

Washington Nuclear Project-2
NRC Inspection Report 50-397/96-24

Operations

- Poor communications on the part of a senior reactor operator contributed to minor injury of two maintenance workers (Section M1.3).

Maintenance

- Drywell pressure instruments, associated with initiation of high pressure core spray (HPCS), were installed in an inappropriate configuration (Section M1.2).

- Poor work planning contributed to minor injury of two maintenance workers (Section M1.3).

Engineering

- Non-conservative engineering decisions were associated with scheduling repair of the residual heat removal (RHR) keepfill Pump RHR P-3, and resulted in Pump RHR-P-3 failure on October 16, 1996, and RHR Train C being inoperable. Corrective actions subsequent to pump failure were too narrowly focussed on the keepfill pump, and did not address other apparent RHR component problems (Section E8.1).

- Licensee engineers demonstrated good performance in identifying that WNP-2 had been in an unanalyzed condition. A spare electrical circuit breaker in safety-related 4160 volt switchgear was stored in a "racked out" position which was not addressed by the seismic analysis. The breaker could have affected the operation of adjacent breakers during a seismic event (Section E8.3).

Plant Support

- Although a commitment to provide onshift dose assessment capability was included in plant procedures, the commitment was not clearly described in the facility emergency plan. Further evaluation of this issue will be conducted by NRC headquarters personnel (Section P3.1).

Report Details

Summary of Plant Status

The inspection period began on October 27, 1996, with the reactor at 90 percent power and the licensee evaluating problems associated with the RRC system adjustable speed drives. On November 1, the licensee reduced power to 53 percent to repair the adjustable speed drives. Following the repairs, the licensee returned the plant to full power on November 3. On November 9, the licensee reduced power to perform scheduled maintenance and surveillance tests. On November 10, the licensee returned the plant to full power. The plant remained at 100 percent power until December 7, when operators reduced power to 66 percent to perform a rod sequence exchange and scheduled surveillances. At the conclusion of the period, the reactor was at 70 percent power with plant operators increasing power after the completion of the scheduled surveillances.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. The conduct of operations was generally professional and safety-conscious.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns (71707)

The inspectors walked down accessible portions of the following engineered safety feature systems:

- Reactor Core Isolation Cooling System
- Control Room Ventilation System
- Low Pressure Core Spray System
- Remote Shutdown Panel
- RHR Trains A, B and C
- HPCS System

Equipment operability, material condition, and housekeeping were acceptable in all cases. The inspectors identified no substantive concerns as a result of these walkdowns.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703, 61726)

The inspectors observed all or portions of the following work activities, as noted below:

- Plant Procedures Manual (PPM) 7.4.3.2.1.4, Division I Leak Detection Monitor Channel Functional Test (CFT)/Channel Check
- PPM 7.4.3.9.1.1, Feedwater/Turbine Trip Actuation on Reactor High Level 8 - CF CFT
- PPM 7.4.3.3.1.53, HPCS Initiation Drywell Pressure High A & C - CFT/Channel Check
- Work Order Task (WOT) WF40-01, Condensate Demineralizer Septa Modification (Documentation Review)
- WOT BYM3-01, Cond-V-113F Valve Refurbishment (Documentation Review)

The performance of the surveillances was generally acceptable. Technicians demonstrated good work practices and performed each task in a professional and thorough manner. However, concerns were identified with the installation of the drywell pressure instruments (HPCS initiation instrumentation, Section M1.2) and with work planning associated with two tasks that were performed concurrently (Section M1.3).

b. Observations and Findings

M1.2 HPCS Instrumentation

a. Inspection Scope (62703)

During surveillance testing, the licensee recently identified several instances where the instrument setpoints for drywell Pressure Instruments MS-PS-47A, B, C and D, drifted substantially. The inspectors reviewed test documentation and observed the licensee's progress through the investigation and corrective action processes.

b. Observations and Findings

The MS-PS-47A, B, C and D instruments are utilized to initiate the HPCS system in response to a high drywell pressure condition. The control system utilizes a "one out of two twice" logic format. The instruments are located in the reactor building, in a relatively mild environment. Maximum reactor building temperature, as specified in the Final Safety Analysis Report (FSAR), is 104°F.

During refueling outage R11, the licensee modified the HPCS system and installed upgraded pressure switches. The new pressure switches had stainless steel diaphragms and were considered to be more reliable. Post installation testing was performed without event.

The maximum allowable trip setpoint, per Technical Specifications, is 1.85 psig (51.2 inches of water). The licensee normally calibrated the switches to trip at approximately 45 inches of water. During quarterly surveillance testing the licensee identified the following problems:

- On June 30, 1996, the as-found setpoint for MS-PS-47C drifted to 52.6 inches of water (Problem Evaluation Request (PER) 296-0553). The instrument was recalibrated and returned to service.

- On November 23, 1996, the setpoint for MS-PS-47C was found to be 27.4 inches of water (PER 296-0807), representing a drift of almost 20 inches from the nominal setting of 45 inches of water. The instrument was considered operable because the drift was in the conservative direction.

- On November 25, 1996, the setpoint for MS-PS-47B was found to be 19.5 inches of water (PER 296-0812).

- During several other surveillances, some of the instrument setpoints appeared to drift an unexpected amount since the previous surveillance (about 5 inches of water).

In response to the above findings, the licensee replaced MS-PS-47B and C and shortened the surveillance interval to weekly. An onsite analysis of one of the removed instruments detected no abnormalities. The licensee shipped the remaining instrument to the vendor for further inspection. The licensee considered all of the installed instruments to be operable based on the successful surveillance testing.

On December 4, 1996, the inspectors reviewed environmental qualification test documents and noted that the records indicated that the instruments, as installed in the plant, were very sensitive to temperature fluctuations. The inspectors shared this information with the licensee to expedite resolution of the safety issue.

The licensee considered the environmental qualification data and subsequently identified that the drywell pressure instruments were installed in the wrong configuration (PER 296-0829). The instrument housing was supposed to be vented to the reactor building, but was not. As a result, the instrument used a closed volume of gas as a reference for measuring drywell pressure. The pressure of the gas within the closed volume was extremely sensitive to temperature changes - a 30°F temperature change could increase the setpoint by 28 inches of water. Additionally, the instrument setpoint was sensitive to changes in barometric pressure - a barometric pressure increase of 5 inches of water would result in a setpoint decrease of 5 inches of water.

On December 5, in response to the installation error, the licensee performed an as-found check of the instrument setpoints and found two units out of tolerance. The setpoints for MS-47-A and C were found to be 55.0 and 54.0 inches of water, respectively (PER 296-0837). The vent plugs were subsequently removed and the instruments were recalibrated. Since removing the plugs, the licensee continued to perform instrument calibrations on a weekly interval.

At the conclusion of the inspection, the licensee was assessing past operability and attempting to identify the root cause for the installation error. This issue is an unresolved item pending further NRC review of the licensee's evaluations and corrective actions (URI 397/9624-01).

c. Conclusions

One unresolved item was opened regarding the incorrect installation of safety-related drywell pressure switches (HPCS control circuitry). Past operability and root-cause evaluations were not completed at the end of the inspection period.

M1.3 Work Planning

a. Inspection Scope (62703)

PER 296-0775 documented an instance where poor coordination between two jobs (within the same clearance order boundary) resulted in minor injuries to two maintenance workers. The inspectors reviewed work related documents, discussed the issue with the licensee's staff and reviewed the planned corrective actions.

b. Observations and Findings

On November 13, 1996 two jobs on the condensate system were worked within the same clearance order work boundary (WOT WF40-01, "Condensate Demineralizer 1F Septa Modification" and WOT BYM3-01, "Cond-V-113F Valve Refurbishment"). Cond-V-113F would normally have been an isolation valve for the condensate demineralizer work. However, in order to work both jobs at the same time, other valves downstream of the Cond-V-113F were utilized for the isolation function.

At the start of the condensate demineralizer job, Valve Cond-V-113F and the downstream isolation valves were in the closed position. The clearance order indicated that the piping between the 113F valve and the other isolation valves was pressurized with air and the line should be vented. This was not accomplished prior to the work. Workers did not know that the line was pressurized when they opened Cond-V-113F and vented the air to the demineralizer, where two other mechanics were working.

The inrush of air into the condensate demineralizer startled the workers (one worker commented that it sounded like a bomb). In fear for their safety, both workers hastily exited the demineralizer cavity. One man was slightly injured when he dove from the demineralizer and onto a service platform. The other aggravated an existing neck injury while attempting to exit. Neither worker was seriously injured or contaminated.

The licensee investigated the incident and concluded that poor work controls and inadequate operation's oversight were contributors. More involvement by operations personnel was needed to ensure proper control of the venting evolutions. Furthermore, the licensee determined that the senior reactor operator had failed to properly notify the workers that the line required venting. As corrective actions, the licensee counselled the senior reactor operator and initiated procedure changes to require more operations involvement when system venting is required. The licensee's planned corrective actions appeared acceptable.

c. Conclusions

Two workers were injured when air was inadvertently vented into the condensate demineralizer cavity where they were working. Contributors to the event included poor coordination of two jobs that were within the same work boundary, weak work controls to control system venting, and inadequate operation's oversight. Planned corrective actions appeared acceptable.

III. Engineering

E1 Conduct of Engineering

E1.1 Power Uprate Calculations

a. Inspection Scope (37551)

The licensee identified that Calculation ME-02-85-75, Revision 2, which analyzes the heat removal capacity of a single service water pond during an accident, had not been reviewed prior to implementing the reactor power uprate during the spring 1995 refueling outage (PER 296-0787). The inspectors reviewed pertinent documentation associated with this finding.

b. Observations and Findings

In response to the noted issue, the licensee determined that failure to review the noted calculation was not risk significant because the service water pond had margin in excess of that required for the power uprate.

The inspectors noted, however, that this was not the first such oversight since power uprate implementation. PER 295-1049, dated September 20, 1995, documented an instance where surveillance procedures (associated with average power range monitoring thermal time constant tests) were not modified to account for parameter changes which were the result of the power uprate. The corrective actions to this finding did not consider the generic implications of the issue.

At the end of the inspection period, the licensee was assessing the cause of the apparent oversight involving the service water ponds and determining the scope of the potential problem. This is considered an unresolved item pending further NRC review of the licensee's investigation and corrective actions (URI 397/9624-02).

c. Conclusions

One unresolved item was identified pertaining to the failure to review calculations, associated with the heat removal capacity of the service water ponds, prior to implementation of the power uprate.

E2.2 Review of Facility and Equipment Conformance to FSAR Description

A recent discovery of a licensee operating their facility in a manner contrary to the FSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the FSAR description. While performing the inspection discussed in this report, the inspectors reviewed the applicable portions of the FSAR that related to the areas inspected. One issue was identified and documented in Section E8.2 of this report.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Open) Inspector Followup Item 50-397/9621-01: **RHR keepfill pump (P-3) failure:** On October 16, 1996, RHR keepfill pump P-3 tripped on thermal overloads due to the catastrophic fatigue failure of the inboard pump bearing (PER 296-0718). RHR P-3 services Trains B and C of RHR (low pressure coolant injection lines). In response to the pump failure, operators promptly started the RHR B pump to maintain the operability of Train B. However, fill was lost in Train C, which rendered RHR C inoperable. The inspectors reviewed the licensee's corrective actions and precursors to the event.

Details: In May, 1995, the licensee rebuilt the RHR P-3 pump, which included replacement of the bearings. On June 4, 1995, the licensee monitored bearing

vibration and noted a substantial step increase in the vibration readings (PER 295-0701).

In response to the step increase in vibration, the licensee performed a visual inspection of the lubrication oil and found metal particles that appeared to originate from the bearings. Additionally, the site vibration engineer performed frequency response analysis of the vibration data. The engineer utilized guidance from "Tracking of Rolling Element Bearing Failure Stages Using Vibration Signature Analysis," dated March 1988, and determined that the excessive vibration was due to a "third stage" bearing defect. According to the guidance document, a third stage defect is indicative of a degraded bearing that is approaching end of life. Additionally, bearing failure would be difficult to predict because the rate of wear at this stage was highly unpredictable.

Based on the above information, the vibration engineer recommended immediate replacement of the bearing. However, the system engineer did not agree with the recommendation for immediate replacement and instead initiated increased frequency vibration monitoring (for approximately 2 months). Pump RHR-P-3 was considered to be degraded but operable and the system engineer scheduled bearing replacement for Outage R11 (April, 1996). Due to scheduling problems, however, the work was repeatedly deferred and was last scheduled to be performed during Outage R12 (April, 1997).

Early keepfill bearing degradation has been a long standing problem at WNP-2 (all of the emergency core cooling systems (ECCSs) and the RCIC system have the same type of keepfill pumps). The design life of the bearings was 40 years, but at WNP-2 bearing life varied between 1 and 10 years. In late May 1995, the licensee identified a design application error associated with the bearings. The design error was made prior to plant construction and was the cause of the premature bearing failures. To correct the problem, the licensee selected a new bearing for use in the keepfill pumps. The new bearings were to be installed when the old style bearings reached their end of life (as detected by the vibration monitoring program). However, the older style bearings were in RHR P-3 at the time of pump failure. At the close of this inspection period, all of the ECCS keepfill pumps were utilizing the improved design bearings.

NRC Assessment: Considering 1) the anomalous behavior of the RHR-P-3 bearing (a step increase in vibration levels shortly after installation); 2) the known design application deficiency; 3) the advanced stage of degradation noted in June 1995 (including wear particles in the bearing oil); and 4) bearing failure would be difficult to predict, the inspectors determined that engineering did not make a conservative decision associated with bearing replacement, thereby demonstrating a weak safety focus when attempting to resolve this problem. Additionally, the failure to perform timely bearing replacement resulted in Pump RHR-P-3 failure on October 16, 1996, and also rendered Train C of RHR inoperable. Corrective actions subsequent to the pump failure were narrowly focussed on the keepfill pump itself and did not address

other apparent component problems, for example, excessive leakage past the RHR pump discharge check valve).

Safety Classification of ECCS System Components: During this inspection period, the inspectors questioned the licensee's nonsafety classification of the ECCS pump discharge check valves and the ECCS keepfill pumps. The ECCS keepfill pumps and the ECCS pump discharge check valves (closing position only) are not within the scope of the licensee's inservice testing (IST) program.

Previously, the NRC had questioned the safety classification of the ECCS keepfill pumps (NRC Inspection Report 397/94-29), with regard to inclusion of the pumps in the licensee's IST program. In 1995, the Office of Nuclear Reactor Regulation (NRR) reviewed the licensee's justification for the nonsafety classification of the pumps and provided the NRC's position in a letter to the Director, Division of Reactor Projects, Region IV (dated December 20, 1995). NRR concluded that the licensee's rational was acceptable. Specifically, the letter stated, in part:

> "Maintaining the ECCS discharge lines filled with water mitigates the consequences of an accident by facilitating quick injection of water into the reactor vessel. Inclusion of waterleg pumps in an IST program is left to the discretion of the licensee if there are other means to maintain the discharge lines filled with water, and components associated with those alternate methods are safety-related."

During the current inspection period, the inspectors contacted NRR and requested clarification on the above. The inspectors were informed that in response to a keepfill pump failure, operators would be expected to start an ECCS pump to keep the line full of water. Boundary valves would be expected to have closing safety functions, and would need to be sufficiently tight to ensure that system pressure remained high enough to accommodate the starting of the ECCS pump (if system pressure dropped below acceptable levels, the ECCS could be rendered inoperable). If fill was inadvertently lost, then refill of the system should be accomplished with safety-related components (the licensee had no established method for refilling the line using only safety-related components).

The inspectors noted that, in the event of a keepfill pump failure, the licensee was relying on nonsafety related functions of equipment to maintain the ECCS piping full of water. Specifically, the ECCS pump discharge check valve would need to close and remain relatively leak tight in order to enable operators to start the ECCS pump. Additionally, there was no surveillance program in place to verify that an ECCS pump could be started (without subjecting the piping to a water hammer) in the event of a keepfill pump failure. Furthermore, as demonstrated by the RHR P-3 failure, operators did not always have sufficient time to start the ECCS pumps prior to losing system fill.

The inspectors identified additional concerns regarding the closing safety classification of the ECCS pump discharge check valves and keepfill pumps. It appeared that these components may be required to operate for accident mitigation. Per Chapter 15 of the FSAR, the ECCSs are required to automatically inject in response to loss of coolant accidents [(LOCAs), upon receipt of a low reactor water level signal]. Although each ECCS is equipped with automatic injection valves that cycle open and closed to maintain water level during the event (with the pump running continuously), it is not a Chapter 15 requirement to operate the systems in this manner. Furthermore, plant operators indicated that, if sufficient time was available between injections, the ECCS pumps would be secured to minimize wear on the pumps. The system logic would subsequently be reset to align the systems for auto initiation on a low level signal. The failure of a pump discharge check valve to close or the failure of the keepfill pump to operate (when the ECCS pump is secured) could render the ECCS train inoperable. Therefore, it appeared that the licensee was relying on these components to help mitigate the consequences of LOCAs (by maintaining the ECCSs operable).

The NRC's final concern dealt with the potential system response during a loss of offsite power concurrent with a LOCA. When the loss of offsite power occurs, the ECCSs could be de-energized for several seconds (at least 10) before power is restored to the pumps. If the ECCS pump discharge check valves did not remain relatively leak tight the ECCSs could loose fill. When the pumps were re-energized the piping could be subjected to a water hammer. Additionally, the ultimate injection time could exceed 27 seconds.

Although the closing functions of the check valves were not within the scope of the IST program, the inspectors noted that this function was inadvertently being tested during ECCS IST. After securing an ECCS pump, operators were required to verify that the low system header pressure alarm clears. The failure of the alarm to clear would be an indicator that the ECCS pump discharge check valve did not close. Although this test adequately demonstrated check valve closure, it did not demonstrate that the valve leakage was within acceptable limits.

The inspectors were working with NRR and the licensee regarding the safety classification of this system. This item will remain open pending final resolution.

E8.2 <u>(Closed) Unresolved Item 50-397/9617-01</u>: **Deferral of Reactor Feedwater (RFW) Pump trip test:** This item pertained to the licensee's deferral of one test associated with the RRC and RFW systems. The licensee had originally planned to trip one RFW pump from 100 percent reactor power to verify proper operation of RFW and RRC scram avoidance capabilities. All testing, with the exception of the RFW pump trip test, was completed on October 15, 1996.

Per the FSAR, the RRC system was designed with a recirculation runback feature. The control circuit reduced reactor recirculation system flow in the event of a RFW pump trip from power levels as high as 100 percent. The intent of the runback was

to decrease reactor power to within the capacity of the remaining RFW pump, thus avoiding a scram on low reactor water level. The inspectors noted that this design feature had been tested during preoperational testing in 1984. Additionally, via the FSAR, the licensee was committed to NRC Regulatory Guide 1.68, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," which included the performance of a RFW pump trip test during the initial startup testing program.

Successful accomplishment of this design feature would require appropriate system response from both the RRC and RFW systems (both of which were modified substantially during Refueling Outage R11). The RRC system modification involved a change in the original recirculation system flow control valve rate of approximately 7 percent per second to the new adjustable speed drive system rate of approximately 4.8 percent per second, raising a question of potential impact on system scram avoidance capability.

The inspectors questioned the relationship between recirculation flow control valve rate and the adjustable speed drive rate, and the engineering analysis that the licensee had performed to determine that testing could be deferred or not performed. General Electric had performed an analysis (prior to the setpoint change), and determined that an acceptable setting for adjustable speed drive runback rate was between 3 and 15 percent per second. The inspector's review indicated that differences in system component response characteristics (between the old flow control valve and the new adjustable speed drive pump) resulted in relatively minor change in actual system flow rates. In fact, the new system actually resulted in a slightly higher recirculation flow rate change, which would improve scram avoidance margin. Accordingly, the inspectors concluded that the original design intent had been maintained and deferral of the testing was acceptable.

This item is closed.

E8.3 Electrical Breakers Not Seismically Qualified in the Test/Disconnect Position

On November 22, 1996, licensee engineers demonstrated good performance in identifying that WNP-2 had been in an unanalyzed condition. A spare electrical circuit breaker in the safety-related 4160 volt (E-SM-8) switchgear was stored in the "racked out" position and this particular configuration was not addressed by the seismic analysis. The breaker could have affected the operation of adjacent breakers during a seismic event. In response to the finding, the licensee made a 1-hour phone notification to the NRC. As an immediate corrective measure, the spare breaker was removed and placed in an approved enclosure. Additionally, other safety-related breaker enclosures were inspected and no other problems were identified. The resident inspectors will perform additional followup to this issue in response to the pending Licensee Event Report.

IV. Plant Support

R8 Miscellaneous Issues (92904)

R8.1 Gold Cards

a. Inspection Scope

The licensee identified numerous instances where employees inappropriately wrote "Gold Cards" in lieu of PERs. The inspectors reviewed associated documentation and discussed the issues with the licensee.

b. Observations and Findings

Incorrectly documenting potential safety issues on Gold Cards instead of PERs has been a repetitive occurrence at WNP-2. Problems associated with Gold Cards do not receive the same level of review as do PERs. PERs 295-1195 and 196-0357 documented similar problems.

Employees from various organizations had failed to write PERs for issues where PERs were required. However, the Health Physics organization committed a disproportionate number of the oversights (at least 30 percent). The licensee was considering the corrective actions at the conclusion of the inspection period. This issue is unresolved pending further NRC review of the corrective measures (URI 9624-03).

c. Conclusion

One unresolved item was identified concerning the failure to write PERs, when appropriate.

P3 Emergency Preparedness Procedures and Documentation

P3.1 Licensee Onshift Dose Assessment Capabilities (TI 2515/134)

a. Inspection Scope

Using Temporary Instruction 2515/134, the inspectors gathered information regarding:

- Dose assessment commitment in emergency plan
- Onshift dose assessment emergency plan implementing procedure
- Onshift dose assessment training

b. Observations and Findings

On December 16, 1996, the inspectors conducted an in-office review of the emergency plan and implementing procedures. The inspectors conducted a telephone interview with the licensee on December 17, 1996, to verify the results of the review. Based on the documentation review and licensee interview, the inspectors determined that the licensee had the capability to perform onshift dose assessments using the real-time effluent monitor and meteorological data and this was required by plant procedures; however, the commitment was not clearly described in the emergency plan.

c. Conclusion

Although the onshift dose assessment capability existed, the commitment was not clearly described in the emergency plan. Further evaluation of the information obtained using the temporary instruction will be conducted by NRC Headquarters personnel.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management after the conclusion of the inspection on December 24, 1996. 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.

ATTACHMENT

Supplemental Information

PARTIAL LIST OF PERSONS CONTACTED

Licensee

P. Bemis, Vice President for Nuclear Operations
L. Fernandez, Licensing Manager
A. Langdon, Acting Operations Manager
J. Muth, Quality Support Supervisor
B. Pfitzer, Licensing Engineer
G. Smith, Plant General Manager
J. Swailes, Engineering Director
D. Swank, Regulatory Affairs Manager
R. Webring, Vice President Operations Support

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observations
IP 71707:	Plant Operations
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
TI 2515/134:	Licensee Onshift Dose Assessment Capabilities

ITEMS OPENED AND CLOSED

Opened

50-397/9624-01 URI	Incorrect HPCS instrument installation
50-397/9624-02 URI	Failure to review calculations for power uprate
50-397/9624-03 URI	Failure to write PERs

Closed

50-397/9617-01 URI feedwater pump trip test deferral

Discussed

50-397/9621-01 IFI RHR keepfill pump failure

LIST OF ACRONYMS USED

CFT	channel functional test
ECCS	emergency core cooling system
FSAR	Final Safety Analysis Report
HPCS	high pressure core spray
IST	inservice testing
LOCA	loss of coolant accident
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
PER	Problem Evaluation Request
PPM	plant procedure manual
RFW	reactor feedwater
RHR	residual heat removal
RRC	reactor recirculation control
URI	unresolved item
WNP-2	Washington Nuclear Project-2
WOT	work order task