U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No:	50-397/92-43
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:	December 28, 1992 - February 15, 1993
Inspectors:	R. C. Barr, Senior Resident Inspector D. L. Proulx, Resident Inspector W. L. Johnson, Resident Intern

Approved by: [signature] 3.22.93

P. H. Johnson, Chief
Reactor Projects Section 1

Date Signed

Summary:

Inspection on December 28, 1992 - February 15, 1993 (Report No. 50-397/92-43)

Areas Inspected: Routine 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, new fuel receipt, safety assessment and procedural adherence. During this inspection, Inspection Procedures 40500, 60705, 61726, 62703, 71707, 90712, 92700, 92701, 92702 and 93702 were used.

Safety Issues Management System (SIMS) Items: None.

Results:

General Conclusions and Specific Findings

Significant Safety Matters: None.

Summary of Violations and Deviations: Two violations were identified. One violation involved failure to repair a drywell purge exhaust valve as required by the Technical Specifications. The other involved four

instances of failure to follow approved procedures related to annunciator response, the issuing of problem evaluation requests (PERs), and surveillance testing of the high pressure core spray (HPCS) battery.

One non-cited violation was also identified, involving failure to restart a continuous airborne radioactivity monitor for the reactor building.

Open Items Summary:

Two followup items and nine LERs were closed; two enforcement items and one followup item were opened. One non-cited violation was opened and closed during this inspection.

DETAILS

1. Persons Contacted

V. Parrish, Assistant Managing Director for Operations
*J. Baker, Plant Manager
L. Harrold, Maintenance Division Manager
*G. Smith, Operations Division Manager
*R. Webring, Technical Services Division Manager
G. Sorensen, Regulatory Programs Manager
D. Pisarcik, Radiation Protection Manager
A. Hosler, Licensing Manager
S. Davison, Quality Assurance Manager
J. Peters, Administration Manager
W. Shaeffer, Operations Manager
*C. Fies, Licensing Engineer

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

*Attended the Exit Meeting on March 15, 1993.

2. Plant Status

At the start of the inspection period, the plant was at 100% power. On January 21, 1993, an automatic reactor scram was received due to low level in the reactor vessel (caused by a feedwater pump trip -- see paragraph 4.a), and the licensee cooled the plant down to Mode 4 for corrective actions and other forced outage work. The shutdown time was extended an extra 5 days due to an inadvertent excessive discharge of the high pressure core spray (HPCS) battery (paragraph 4.d). Additional balancing weights were also added to the main turbine shaft based on vibration readings taken during the previous operating period.

The plant was restarted on January 28, 1993 and reached 3% power before being shut down due to a steam leak in the turbine building. The reactor was restarted on January 30, 1993, but was shut down on January 31 due to excessive turbine vibration. Adjustments were made to the main turbine balancing weights, and the reactor was restarted on January 31, but was shut down again on February 1, 1993, because of excessive turbine vibration. The reactor was cooled down to Mode 4 (Cold Shutdown) to evaluate a low oil level in a recirculation pump; the balancing weights were also removed from the turbine shaft, and other maintenance activities were performed. Drywell purge valve CEP-V-4A was also repaired (paragraph 4.e) after the licensee determined that it had not been reworked, as required, during the January 21 outage.

The reactor was restarted on February 4, 1993, but was manually scrammed from 31 percent power on February 6, because the "A" recirculation pump tripped while operators were attempting to shift it to fast speed operation (paragraph 4.f). The reactor was restarted on February 7, 1993. On February 10, when the reactor was at 92% power, the reactor automatically

scrammed due to failure of a reactor feed pump governor electrical connector. The "B" feedwater pump suction relief valve lifted and stuck open following this event, prompting operators to isolate the reactor and declare an Unusual Event because of a suspected steam line break in the feedwater pump room (paragraph 4.g). This event prompted utility management to declare a "time out" (paragraph 4.i) and the plant was placed in Mode 4 to permit an assessment of the events of the previous three weeks. The plant was in Mode 4 at 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) Followup Item (90-28-03): Weaknesses in Diesel Fuel Oil (DFO) Procurement and Testing

During a review of the licensee's program for procurement and testing of DFO, the inspector identified that the licensee's actions to demonstrate compliance with ASTM D975-81 were incomplete. The inspector was concerned with the limit established by the licensee for the "cloud point." WNP-2 procured their DFO with a cloud point of 32 degrees F on the basis of the DFO tanks being underground. The analysis by the Supply System noted, however, that when new DFO was being delivered, the tanker trucks were occasionally delayed and remained outside in very cold weather well below 32 degrees F for several days. This anomaly was addressed in licensee memorandum RFTS-10-172 dated February 6, 1990. The request for technical services (RFTS) recommended additional sampling and calculations to verify the usability of the DFO if the oil tankers had remained outside exposed to temperatures below the cloud point. This RFTS had not been acted upon several months later. In December 1992, the licensee revised Plant Procedures Manual (PPM) 7.4.8.1.1.2.3A, "Diesel Generator New Fuel Testing," to include the additional sampling and calculations recommended in RFTS-10-172. The inspector verified the licensee's actions and considered them to be satisfactory. This item is closed.

b. (Closed) Violation (92-09-01): No Flashing Light Installed at High-High Radiation Area Boundary

During a tour of the reactor building, the inspector found a High-High Radiation Area that did not have an operational flashing light to warn employees of the hazard. This was a violation of Technical Specification 6.12.1. For corrective actions, the licensee instituted a policy of requiring at least two flashing lights at each High-High Radiation Area boundary, implemented a design change to the lights to drill holes in the covers for better heat dissipation, increased the frequency of light bulb changeouts, and added an operational check of flashing lights to the daily HP tour checklists. For long term corrective actions, the licensee initiated a "Source Term Reduction Program." This program includes plans for hot spot flushing, chemical decontamination and other design changes

to reduce the number of high radiation areas. The inspector reviewed the licensee's corrective actions and considered them to be satisfactory. This item is closed.

4. Event Followup (93702)

a. Reactor Feedwater Pump (RFP) Trip and Reactor Scram

On January 21, 1993, the reactor scrammed from full reactor power due to low reactor pressure vessel (RPV) level (Level 3 at +13 inches). A trip of the "A" RFP coupled with an apparent failure of the "A" recirculation flow control (RFC) valve to run back to minimum per design was the apparent cause of the low vessel level. Just prior to the event operators received a fire alarm in the "A" RFP room. This alarm was followed shortly by "High Vibration" and "High Thrust Bearing Wear" alarms for the "A" RFP. The "A" RFP subsequently tripped. However, following the trip of the RFP, the "B" RFC valve ran back to minimum, but the "A" RFC valve ran back to 82% and stopped in that position. Due to the feed flow/steam flow mismatch, RPV level decreased to +13 inches and an automatic reactor scram occurred.

The emergency operating procedures (EOPs) were entered based on level going below +13 inches in the reactor vessel. Reactor vessel level reached a minimum of -22 inches, and operators recovered RPV level with the reactor core isolation cooling (RCIC) system. All safety systems responded as expected following the scram. The operators appeared to perform well in handling the scram. The plant was stabilized and a controlled cooldown to Mode 4 (cold shutdown) was executed.

Licensee investigation of the scram indicated that a painter had accidentally actuated the fire protection manual "deluge pull station" in the "A" RFP room, causing the sprinkler system to actuate. This sprayed water on the "A" and "B" RFP vibration monitoring panels, resulting in the above alarms and trip of the "A" RFP. The inspectors apprised licensee management that a previous inspection finding had identified a need for closer oversight of the painters. The event of January 21, 1993 indicated that additional effort in this area appeared warranted. Troubleshooting of the "A" RFC valve indicated that a servo error trip of both hydraulic power units caused the incomplete valve runbacks. The servo error trip signals were generated as a result of slow valve responses and reduced velocity feedback signal gains caused by incorrect control settings. Further investigation revealed that the licensee had not adequately tested the runback feature of the RFC valves. The inspectors reviewed the licensee's initial corrective actions for this event, which appeared to be satisfactory. The licensee submitted an LER for the event.

b. Reactor Vessel Level Anomalies

During the cooldown following the January 21 event, when the reactor was below 150 psi, operators noted RPV level anomalies. The first

level anomaly occurred on channel B of the narrow range instrumentation, in which operators logged that level "drifted" up to 42 inches and then back to 35 inches. Later, operators logged that they "experienced drifting" on both the B and C channels of RPV level. Channel C went above Level 8 (+54 inches) and then came back to 40 inches; then both channels B and C oscillated between 35 and 42 inches. Operators called the instrumentation and control (I&C) shop to troubleshoot the instrumentation. A Problem Evaluation Request (PER) was not generated to document the level anomalies as required by licensee procedure PPM 1.3.12, "Problem Evaluation Requests."

Paragraph 2.1 of PPM 1.3.12 states, in part, that "... A problem is defined as a condition where a physical or performance characteristic of a system, component, or part does not perform to the requirements of design documents, applicable standards, procurement documents, or regulatory requirements for the item." Paragraph 6.1 of PPM 1.3.12 states "... Any person who observes an actual problem or perceives a potentially significant problem shall initiate a PER." I&C contacted engineering, who recommended that the reference legs for the level instrumentation be backfilled. Engineering personnel suspected the level anomalies were due to the phenomenon of "notching" or "degassing", which is caused by voiding of the reference leg during depressurization, due to the release of noncondensible gases. However, a PER was not initiated until February 12, 1993, when the licensee discovered that the degassing could preclude an isolation of shutdown cooling in Mode 3. The licensee reported this issue to the NRC after the end of this inspection report period. The licensee's failure to write a PER on January 21, 1993, is a violation of 10 CFR 50, Appendix B, Criterion V and PPM 1.3.12 (Violation 50-397/92-43-01).

Following the January 21 event, licensee engineering personnel presented the data obtained to the Boiling Water Reactor Owner's Group (BWROG). Licensee personnel stated that they and the BWROG both concluded that the degassing was bounded by previous BWROG analyses. The licensee conducted further training for the operators to provide them with increased awareness in recognizing the degassing and notching phenomena. The NRC will evaluate ongoing licensee actions related to this issue during the next inspection period.

c. <u>Diesel Generator Failures</u>

On January 21, 1993, while performing a test of the #2 diesel generator (DG-2) (unrelated to the reactor trip on that date), DG-2 failed to achieve rated voltage within the required 10 seconds. DG-2 started and increased to approximately 3800 volts, paused, and then slowly increased to rated voltage (4160 V) in about 17 seconds. Operators declared DG-2 inoperable. The plant was in Mode 3 due to the scram discussed in paragraph 4.a above. This event appeared to be a repeat of the failure of DG-2 to achieve rated voltage in the required time in November of 1992.

In November 1992, during a monthly operability test, DG-2 failed to achieve rated voltage in the required 10 seconds. The licensee attempted to repeat the failure to aid in troubleshooting, but was unsuccessful. Licensee engineering and root cause personnel were unable to determine the exact failure mode of DG-2. However, licensee engineers believed that the failure was most likely due to a faulty voltage regulator, which was replaced. After several successful starts, the licensee declared DG-2 operable.

After approximately 15 successful starts following the November 1992 replacement of the voltage regulator, DG-2 failed on January 21. Because of the repeat nature of the problem, the licensee initiated an in-depth troubleshooting plan. DG-2 and its attendant electronic controls were instrumented. The licensee started DG-2 approximately 15 times, and repeated the failure. Licensee analysis of the recorded data revealed that the most likely cause of the failure of DG-2 was in the method the licensee used in setting up the field flash and voltage regulator relays.

During the 1991 refueling outage, because of slow starting times, the licensee replaced the relay which transfers the generator from field flash to voltage regulator control. Instead of using one relay with "open" and "closed" contacts to make the transfer, separate relays were used (after obtaining concurrence from the voltage regulator vendor). The licensee concluded that occasionally, due to the tolerance of the relay actuation times, the voltage regulator was activated before the field flash was terminated. This resulted in the generated output voltage not reaching the minimum Technical Specifications (TS) voltage in the required time. The licensee could not provide a technical explanation of the exact electrical interaction that caused the delay in reaching rated voltage. However, the licensee redesigned the relaying scheme to remove this interaction. DG-2 was then started successfully 10 times, and was declared operable.

The inspectors discussed the repeat failures with licensee management. This issue was also discussed at length with the licensee by Region V and NRR management. During these discussions, licensee management noted that this event emphasized that a thorough investigation must be undertaken when problems first occur, in order to prevent recurrence.

d. <u>Excessive Discharge of the High Pressure Core Spray (HPCS) System Battery</u>

On January 24, 1993, at 11:25 a.m., with the plant in Mode 4 at approximately 140 degrees F, WNP-2 operators removed the high pressure core spray (HPCS) system from service to repair several HPCS fire seals per Maintenance Work Request (MWR) AR9551. Clearance Order (CO) 93-01-0144 established the HPCS system electrical configuration to conduct these repairs. The CO, which had been reviewed by the Clearance Order Review Committee (CORC), the Plant Operations work control representative, and the Shift Manager, had operators secure the HPCS battery charger to ensure

that all cables passing through the fire seals were deenergized. Because the battery charger had been removed from service and DC loads had not been removed from the battery bus, the HPCS battery continuously discharged during the maintenance.

At approximately 5:45 a.m. on January 25, the 125 volt DC low voltage alarm annunciated in the control room, alerting operators that HPCS battery voltage had dropped to approximately 118 volts. The control room operators acknowledged the alarm, referred to the alarm response procedure (P.P.M. 4.601.A1) and notified the Control Room Supervisor (CRS). The CRS did not take the four actions specified in the procedure, one of which was to notify electrical maintenance of the low voltage, because the voltage was considered to be low due to the ongoing maintenance. This is an additional example of a violation of 10 CFR 50, Appendix B, Criterion V (50-397/92-43-01). The CRS also did not require more frequent monitoring of the DC bus voltage.

At approximately 1:50 p.m. on January 25, while attempting to rack in breaker SM-4-2, which had been racked out for this work, electricians were unable to insert the breaker using the rack-in motor, which is powered from the 125 volt DC bus. The electricians also detected the smell of burning insulation when they attempted to insert the breaker. The electrician then inserted the breaker manually. The electricians tried to close the breaker; however, the breaker would not close. At 3:30 p.m. on January 25, 1993, an equipment operator (EO) found the HPCS soak-back pump (powered from 125 volt DC power) with its power supply breaker closed but not rotating. The EO notified the control room operators, who initiated an investigation and a problem evaluation report (PER). Plant electricians found HPCS battery voltage to be approximately 54 volts. The control room operators immediately removed the DC loads from the battery.

Plant management convened an Incident Review Board (IRB) to determine the most probable cause of the event. The IRB concluded in their February 3, 1993 report that the cause was rooted in planning and preparation for the work -- specifically, CO 93-01-0144, the barrier used to mitigate the risk associated with the work, was less than adequate. The report also noted the following factors which contributed to the excessive discharge: inadequate communication of control room personnel, lack of Operations attention and response to a system problem, and lack of procedural guidance. The licensee will document a complete root cause in Problem Deficiency Report (PDR) 293-0080.

As immediate corrective action, the licensee slowly recharged the battery over the next three days. The HPCS battery problem and the licensee's actions were also discussed extensively during conference calls with Region V and NRR management. All battery cells returned to within the requirements of the Technical Specifications; however, several days later the licensee replaced nine of the battery cells because three of the cells exhibited low cell voltages.

The inspectors discussed the event with selected licensee personnel (operators, craftsmen, CORC members, work control personnel, supervisors, and managers), observed battery surveillance testing and cell replacements, reviewed the clearance order, reviewed the maintenance work order, and reviewed and discussed the IRB report with licensee management.

The inspectors found that initial planning for MWR AR9551 estimated the repair would take in excess of 30 hours. However, because management still desired to accomplish the fire seal work during the outage, the job was reviewed again and it was determined that it would take at most 12 hours. The MWR contained no precautions to be applied if the work should exceed the scheduled 12 hours. In the process of drafting the clearance, which would result in discharging the battery because the HPCS diesel soakback pump would be left operating to maintain the HPCS diesel at temperature, the CORC recommended installation of temporary power to maintain a float charge on the battery. However, the Operations representative to the Work Control Center, without referring to the appropriate Technical Specifications or design documents, concluded that discharging the battery was acceptable because the work would be of relatively short duration. (Had the individuals referred to the design basis, they would have recognized that the battery would have been discharged to approximately 90% of its capacity (assuming a 12-hour work duration) and would have been inoperable until fully recharged.)

The job was completed on time; however, during the removal of fuses to establish the initial conditions for the maintenance, a fuse clip was damaged. This was not discovered until restoration of the clearance was initiated. The additional time to correct this problem resulted in the battery being discharged for approximately 26 hours.

The inspectors concluded that the root cause of the event was failure of the licensee to establish an effective forced outage plan and a process for reviewing changes to that plan. Contributing causes were insufficient knowledge of the design basis and the Technical Specifications, and not adhering to procedures (e.g., the annunciator response procedure). The inspectors noted that the IRB review would have been more complete if it had been more critical of management's role in the event and of the forced outage planning process. The inspectors also concluded that the event had no safety significance, because the HPCS battery was not required to be operable for the plant conditions at the time of the event. It appeared, however, that had the EO not been particularly alert and recognized that the soakback pump was not running, Operations may have proceeded with plant restart without recognizing that the HPCS battery was inoperable.

The failure of control room personnel to adhere to the alarm response procedure is a violation of NRC requirements. While the operators were aware that maintenance was in progress involving the HPCS battery, the battery and the HPCS EDG were still considered to be operable. Planning for the fire seal work had assumed that the

battery would remain operable. This violation was identified by the IRB, in parallel with review by the inspectors. However, the inspectors noted that there have been other recent examples of operators' failure to follow alarm response procedures (e.g., see Inspection Report 50-397/92-35). This failure is therefore being cited as a violation, since it appears that it should have been prevented by the licensee's corrective actions for the previous violations.

e. Containment Exhaust Purge Valves 3A/4A (CEP-V-3A/4A)

In November 1992, the licensee deinerted and entered the drywell to identify the source of an increase in drywell unidentified leakage. After locating and correcting the source of the leakage, the licensee reinerted the drywell, then performed a local leak rate test (LLRT) of CEP-V-3A and 4A. The valves failed the LLRT (measured leakage greater that 0.05 L_a). However, TS surveillance requirement 4.6.1.8.2.b allows, if measured leakage is greater than 0.05 L_a but within other specified limits, that the valves may be considered operable if they are secured in the closed position and repaired during the next cold shutdown. The Shift Manager, in entering this requirement into the Limiting Conditions for Operation (LCO) status book, anticipated that the next cold shutdown would be the refueling outage, and indicated repair of the valves as a constraint for restart following the next refueling outage. In addition, the Management Review Committee (MRC) review of the PER generated for the LLRT failure did not identify the requirement in the TS. The containment also was not deinerted during this shutdown period, so no additional LLRT was required.

During the shutdown following the January 21, 1993 scram, the licensee did not repair CEP-V-3A/4A as required by the Technical Specifications. The Plant Operations Committee (POC) also did not identify repair of these valves as a restart constraint, because the POC relied on the Shift Manager's entry in the LCO status book, rather than researching the Technical Specifications. On January 28, 29 and 31 the licensee started up the reactor prior to repairing the CEP valves, in violation of the TS.

On January 29, 1993 the reactor was shut down to repair a steam leak in the turbine building. While the plant was operating, operators had also received an alarm indicating a low oil reservoir level in a recirculation pump motor bearing. Therefore, the licensee deinerted the drywell and entered the drywell. After containment was reinerted on the subsequent startup, an LLRT was performed for CEP-V-3A/4A. This LLRT was in excess of 0.05 L_a, and the licensee entered the TS action statement. However, upon reviewing the PER, the system engineer discovered that previous startups had been conducted in violation of the TS. A PER was generated, and the valves were repaired.

Additional inspector review revealed that the CEP valves had been redesigned twice, and repaired several other times. The licensee is considering replacing the CEP valves in a future refueling outage,

and will submit an LER for this event.

The failure to repair CEP-V-4A during the next cold shutdown after a failed LLRT was a violation of the requirements of TS 4.6.1.8.2.b (Violation 50-397/92-43-02). While the licensee identified this violation, it is being cited because the licensee had not taken appropriate corrective actions by the end of this inspection period. Although the Shift Manager was counseled and disciplined, other actions were not taken to address weaknesses in management oversight and in the reviews performed by the MRC and POC.

f. Recirculation Pump Trip and Manual Reactor Scram

On February 6, 1993, when attempting to shift the "A" reactor recirculation (RRC) pump to 60 Hz, the A RRC pump tripped. Operators manually scrammed the reactor in accordance with operating procedures.

Licensee procedures prescribe increasing power through the region of increased awareness in a controlled manner, with several hold points, including 32 ± 1% power. When the rod pattern analyzed for 32% power was achieved, reactor power was actually at 30.7% power. The licensee procedure allowed for slight deviations from the power band provided a management decision was made that there would be little impact on core stability. Rather than inserting control rods to 25% power and obtaining a new analyzed rod pattern, the Operations Division Manager made the decision to proceed with recirculation pump transfer because little effect on core stability was evident. However, at this lower power level, the licensee was observing intermittent indications on the low feedwater flow interlock indicator lights.

The low feedwater flow interlock trips the recirculation pump if the pump is in fast speed (60 Hz). An operator recalled that there was a 15-second time delay associated with this interlock. Also, the Shift Technical Advisor (STA) found this interlock with a 15-second time delay on a drawing in the control room. The system engineer was not consulted, and no further research into the system design was done. The Operations Division Manager made the decision to attempt the pump shift. However, when attempting to upshift the pump, the pump tripped. Operators manually scrammed the reactor, per licensee procedures. The licensee requires a reactor scram upon recirculation pump trip because single loop operation has not been analyzed for stability considerations. The scram was handled well by the operators without the aid of ECCS systems or RCIC.

After the scram, following considerable additional review of system drawings, licensee engineers found that there was also an instantaneous trip associated with the low feedwater flow interlock. This interlock was installed to permit initial preoperational testing of the system, and was disconnected (after discussions with General Electric) before plant restart. The Supply System stated that the root causes for this event included operators proceeding in the face of uncertainty (e.g., without the aid of the technical experts), and

management oversight being too close to the decision making process.

g. Automatic Reactor Scram due to RFP Governor Failure

On February 10, 1993, following an abrupt stop of the "B" RFP, the reactor automatically scrammed from 92% power due to low level in the reactor vessel (+13 inches). Shortly after the scram the B RFP room was found engulfed with steam. Due to concerns that a steam line break had occurred in the RFP room, the operators shut the main steam isolation valves (MSIVs) and declared an Unusual Event. Operators entered the EOPs, due to low level in the RPV, and supplied makeup to the reactor using RCIC. Pressure was controlled by cycling safety/relief valves (SRVs), and initiating suppression pool cooling. Upon isolation of the source of steam, operators fed the reactor using condensate booster pumps, reopened the MSIVs, and cooled down the plant using bypass valves to the main condenser. The Unusual Event was then terminated. Operators appeared to handle the event well and in a conservative manner with respect to personnel and reactor safety.

The cause of the low level in the reactor vessel appeared to be the sudden stopping of the B RFP due to failure of a electrical connector in the governor. Since the RFP did not trip, but suddenly stopped, a runback of the recirculation flow control valves did not occur. The steam in the RFP room was caused by actuation of the feed pump suction relief valve, which did not reseat. Lifting of the suction relief valve apparently resulted from a pressure surge following the sudden stopping of the "B" RFP. The licensee determined, however, that system pressures had remained well below design pressure.

The failure of the electrical connector in the feed pump governor was a repeat event. Previous licensee analysis had indicated that the mean time to failure for these connectors was approximately two years. The licensee was planning to replace these connectors during the R8 refueling outage. The licensee stated the electrical connectors had a tendency to corrode because of moisture intrusion in the connector's housing. The licensee was considering a design change to the RFP governor electrical connectors to alleviate this problem. The licensee is submitting an LER for this event.

h. Other Performance Issues

On January 21, 1993, just prior to the cooldown following the scram, a licensee employee noted steam issuing near MS-V-239. The valve packing was replaced. On January 29, 1993, steam was again seen issuing near MS-V-239, but this time a more thorough investigation revealed that a cracked weld was the cause of the steam leak.

On three occasions during this report period, the licensee attempted to rebalance the main turbine to reduce vibration. Two of these unsuccessful attempts required the reactor to be shut down again for rebalancing. As also concluded by licensee management during their "time out" (see below) this and other instances indicated that

licensee management was too involved in some technical decisions and was not providing sufficient oversight of the decision process.

On February 2, 1993, water was found in the RFP lube oil system due to running the condensate booster pumps without maintaining a vacuum in the main condenser. This problem had been seen previously but was not addressed in operating procedures.

i. Management "Time Out"

On February 11, 1993, in response to the events of the previous three weeks, licensee management initiated a "time out." The purpose of the time out was to determine common themes and lessons learned from the events of this inspection period. Following the time out, licensee management presented their findings and lessons learned to the inspectors on February 14, and discussed them with NRC management during a meeting on March 4, 1993. Management's findings from their time out, as discussed during the management meeting, included conclusions that (1) managers were too involved in technical or operational decisions and were not providing sufficient oversight of the decision process and (2) a perception of excessive pressure for plant restart interfered with effective planning during forced outages. In addition, the licensee conducted integrated plant walkdowns of several safety-related and balance-of-plant systems.

j. Conclusions

The inspectors discussed the events of January 21 through February 10, 1993 with Supply System management. The inspectors noted that these issues indicated a clear and continuing need for more effective management oversight of licensed activities, along with continued weakness in procedure quality and compliance, in supervisory control of plant evolutions, and in individual attention to the proper performance of assigned tasks. These concerns were also discussed with licensee management during a management meeting on March 4, 1993 (to be addressed in Meeting Report No. 50-397/93-08). Licensee management agreed that prompt corrective actions were necessary to address the performance issues of this inspection period.

Two violations were identified, as discussed above.

5. Operational Safety Verification (71707)

a. Plant Tours

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:

(1) Operating Logs and Records. The inspectors reviewed records against Technical Specification (TS) and administrative control procedure requirements.

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

(3) Shift Manning. The inspectors reviewed 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) Equipment Lineups. The inspectors verified that valves and electrical breakers were 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) Equipment Tagging. The inspectors observed selected equipment, for which tagging requests had been initiated, to verify that tags were in place and the equipment was in the condition specified.

(6) General Plant Equipment Conditions. The inspectors observed plant equipment 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.

On January 11, 1993, during a tour of the reactor building, the inspector found a fire door propped open by a piece of string. No one was in the immediate area of this fire door, nor was a "Fire Impairment Checklist" present. Two contract employees were working on scaffolding approximately thirty feet above floor level. Plant Procedures Manual (PPM) 1.3.10, "Fire Protection Program," paragraph 6.1.2.c required impairments involving passive fire protection components (i.e., fire doors) to be documented by use of a Fire Impairment Checklist unless all of the following criteria were met: (1) the component was impaired as part of an approved surveillance, test or maintenance task, (2) the impaired component would never be left unattended, and (3) the impaired component could be safely returned to an operable status prior to leaving the area in the event that an evacuation becomes necessary.

The inspector notified the Shift Manager of the discrepancy. The Shift Manager informed the Shift Support Supervisor (SSS), who initiated a Fire Impairment Checklist to correct the immediate problem. However, the Shift Manager did not write a Problem Evaluation Request (PER) to document the occurrence as was required by paragraph 6.1.4.b of PPM 1.3.10. The licensee initiated a PER on January 14 when this was questioned by the inspector. The failure to write a PER for this fire protection infraction, as prescribed by the PPM, is an additional example of a violation of 10 CFR 50, Appendix B, Criterion V, (Violation 50-397/92-43-01).

Subsequent investigation revealed that the contractor employees, who were tasked to work on reactor building seals, had asked the SSS if a Fire Impairment Checklist was required to prop open the fire door to support temporary power installation. The SSS told these workers that a Fire Impairment Checklist would not be required if the fire door was continuously manned. The contractor employees apparently assumed that being in the area, but 30 feet above floor level was adequate to meet this requirement.

The inspector discussed these findings with licensee management, who stated that the employees' interpretation of the fire protection requirements and the Shift Manager's handling of the problem did not meet their expectations.

(8) Plant Chemistry. The inspectors reviewed chemical analyses and trend results for conformance with Technical Specifications 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.

On December 28, 1992, during a tour of the reactor building, the inspector found that regulated air pump RB-3R was turned off and was cold. RB-3R is an airborne radioactivity monitor used for trending of iodines and particulate airborne activity. The inspector reported this condition to Health Physics (HP), who stated that the HP technician apparently forgot to return

the unit to service when the charcoal and HEPA filters were replaced on December 24, 1992. PPM 11.3.24, "Health Physics Tours," requires these monitors to be operating continuously and requires that the sample from this equipment be taken weekly and trended. Because RB-3R was not in continuous operation for a four-day period, inaccurate trending data were obtained, in violation of TS 6.8.1 and PPM 11.3.24. The HP technician changed out the HEPA and charcoal filters on RB-3R, and returned it to service.

The inspector discussed this finding with the HP supervisor, who stated that HP personnel should in the future be aware of the status of the regulated air pumps during routine HP tours. The HP supervisor conducted an investigation and concluded that the root cause of the problem was a personnel error and appropriate actions were taken. In addition, this problem will be discussed in the next continuing training session with the HP staff, with emphasis on self-checking and attention to detail. Because adequate corrective actions were initiated, and because the other criteria of Section VII.B(1) of the Enforcement Policy were met, this violation was not cited (NCV 50-397/92-43-03).

10) <u>Plant Housekeeping.</u> The inspectors observed plant conditions and material/equipment storage to determine the general state of cleanliness and housekeeping. The inspectors evaluated housekeeping in the radiologically controlled area with respect to controlling the spread of surface and airborne contamination.

(11) <u>Security.</u> 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. <u>Engineered Safety Features Walkdown</u>

The inspectors walked down selected engineered safety features (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. The inspectors also observed that proper lubrication and cooling of major components were adequate. The inspectors 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 indicated dates:

System	Dates
Diesel Generator Systems, Divisions 1, 2, and 3.	January 18
Hydrogen Recombiners	January 20
Low Pressure Coolant Injection (LPCI) Trains "A", "B", and "C"	January 20
Low Pressure Core Spray (LPCS)	January 20
High Pressure Core Spray (HPCS)	January 15
Reactor Core Isolation Cooling (RCIC)	January 15
Residual Heat Removal (RHR), Trains "A" and "B"	January 15, 20
Scram Discharge Volume System	January 20
Standby Gas Treatment System (SGTS)	January 20
Standby Liquid Control (SLC) System	January 15
Standby Service Water System	January 15
125V DC Electrical Distribution, Divisions 1 and 2	January 15, 20
250V DC Electrical Distribution	January 15, 20

Two violations were identified, as discussed in paragraphs 5.b(7) and (9) above.

6. New Fuel Receipt (60705)

The inspector reviewed the new fuel receipt evolution, including reviewing the procedures for adequacy, verifying that personnel were complying with procedures, confirming that qualified personnel were used for the operation, and witnessing portions of the fuel receipt operations, from arrival of the fuel on site to placing the fuel into the spent fuel pool. The inspector used the following licensee procedures as guidance:

Procedure No.	Title
PPM 6.2.1	New Fuel Handling, Delivery Truck to Railroad Bay
PPM 6.2.2	New Fuel Handling, Railroad Bay to Refuel Floor
PPM 6.2.3	New Fuel Handling on the Refueling Floor

PPM 6.2.4 New Fuel Inspection

PPM 6.3.9 Channeling and Dechanneling Irradiated Fuel

The inspector observed the adequacy of procedure changes and corrective actions for previous problems during new fuel receipt. The licensee had revised the new fuel handling procedures and added specific hold points to prevent dropping the fuel during critical steps. The inspector observed portions of the fuel handling, and concluded that licensee personnel were using the requisite care in handling the fuel and were adhering to their procedures. In addition, the licensee had revised PPM 6.2.4 to provide for QC inspectors observing the engagement of the tie rod locking lugs, to ensure that the lugs did not become disengaged during fuel channelling, as occurred in 1992. The inspector observed portions of the new fuel inspection and fuel channelling and noted that QC was aware of and adhering to the revised procedures.

On February 2, 1993 while witnessing the installation and torquing of the channel fasteners on the fuel per PPMs 6.2.3 and 6.3.9, the inspector noted that the refueling engineer was signing off procedure steps as they were being accomplished. The refueling engineer was located about 20 feet from where the torquing was performed, and could not hear the click of the torque wrench or see the dial on the torque wrench. The inspector noted that the refueling engineer signing for the torquing had not been trained on torquing procedures, and could not verify that proper torque was being applied. The inspector also did not observe any oral communication between the refueling engineer and the craftsman who was applying the torque to the fastener. The inspector noted that PPM 6.3.9 also contained signature blocks for torquing of the channel fasteners. Neither procedure appeared to be clear to where the signatures were required to be made. Because of this observation the inspector questioned the licensee as to the acceptability of containing the same signoff in two procedures. The inspector was concerned that the confusing nature of these two procedures could lead to missing the signoffs. In addition, PPM 6.2.3 did not contain acceptance criteria for the torque wrench range or calibration due date.

The inspector notified the Quality Control (QC) Manager of his concerns. The QC Manager discussed these findings with the appropriate personnel, and PPM 6.2.3 was revised to include data blocks for the serial number and calibration due date for the torque wrench. In addition, QC conducted training for the engineers on torque verification. The Fuels Engineering Manager also stated that the refueling engineer was not performing an independent verification of the torquing, but was signing off on the procedure to maintain a status of the steps accomplished. However, licensee management acknowledged that PPMs 6.2.3 and 6.2.9 contained weaknesses, and that improvements will be made in the future. The inspector will followup the licensee's actions in a future inspection. (Inspector Followup Item (IFI) 50-397/92-43-04)

No violations or deviations were identified.

7. Safety Assessment (40500)

The inspector reviewed the licensee's self assessment capability with respect to the offsite review committee, the Corporate Nuclear Safety Review Board (CNSRB). The inspector used the Technical Specifications and licensee procedures as guidance. In addition, the inspector attended the CNSRB meeting of February 5-6, and reviewed the minutes of that meeting.

The inspector concluded that, overall, the CNSRB provided an objective review of Supply System performance. The CNSRB was particularly critical of the Plant Operations Committee (POC). The CNSRB noted that the POC did not adequately question the reason for numerous changes to procedures that had been performed numerous times in the past, nor had POC trended these numbers. Some CNSRB members also commented that the Plant Manager (PM) should not be a member of POC so that the PM can have more of an oversight role and less of a line function. The inspector also considered observations of the CNSRB on LER reviews and discussions of the power oscillation event of August 15, 1993 to be positive.

However, the inspector questioned the depth of CNSRB review of changes made pursuant to 10 CFR 50.59. Several of the CNSRB members commented that the 50.59 safety evaluations completed by the Supply System appeared to be of the same quality they had seen at other sites. The inspector noted to the CNSRB that these reviews appeared to be cursory in nature. In addition, the licensee's QA organization also had performed more in-depth technical reviews of the Supply Systems's 50.59 safety evaluations and made a presentation to the CNSRB. Neither the QA organizations nor the CNSRB members had any findings. During this same period, however, the NRC had cited the licensee three times for problems with the 50.59 process.

The inspector discussed the above observations with the QA Director, who stated that improvements would be made in the quality of 50.59 reviews, in that they are considering the establishment of a CNSRB subcommittee which would perform a more in-depth technical review.

No violations or deviations were identified.

8. Surveillance Testing (61726)

The inspectors reviewed surveillance tests required to be performed by the Technical Specifications 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.

Portions of the following surveillance tests were observed by the inspectors on the dates shown:

Procedure	Description	Dates Performed
7.4.3.7.1.16	Area Radiation Monitor (ARM) Channel Functional Test	January 20
7.4.8.1.2.1.2	HPCS Monthly Operability Test	January 28
7.4.3.6.1.13	Intermediate Range Monitor C Channel Functional Test	January 22
7.4.3.1.1.64	Scram Discharge Volume Float Switch Operability Checks	January 22

In addition to the above surveillance observations, the inspector followed up on Unresolved Item 92-36-03 associated with the HPCS battery surveillance. During a previous inspection the inspector noted that PPM 7.4.8.2.1.23, "HPCS-B1-DG3 Quarterly Operability Checks," required the user in step 7.1.7 to check the internals of the battery for evidence of flaking and sediment. However, the battery racks were constructed such that the bottom of the cells' internals were obstructed from sight. This step was signed off as satisfactorily completed despite the inability to see if any sediment was present. Further inspector investigation revealed that proper performance of this step was possible in that the licensee used a borescope to verify satisfactory sediment levels in the HPCS battery during subsequent performances of 7.4.8.2.1.23. Failure to inspect the battery for sediment during the surveillance performed on October 20, 1992, as required by PPM 7.4.8.2.1.23, is an additional example of violation of the requirements of 10 CFR 50, Appendix B, Criterion V (Violation 50-397/92-43-01). Unresolved Item 397/92-36-03 is Closed. The licensee adopted a practice of using a borescope to inspect the HPCS battery for sediment, and revised the surveillance procedure to provide appropriate guidance. In view of the actions taken by the licensee, and confirmed by the inspector before issuance of this report, a written response to this violation is not required.

One violation was identified as discussed above.

9. Plant Maintenance (62703)

During the inspection period, the inspectors observed and reviewed documentation associated with maintenance and problem investigation activities to verify compliance with regulatory requirements and with administrative and maintenance procedures, required 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
AP2219; SM-7 and SM-8 Undervoltage Relay Redesign and Replacement	January 21-23
AP2145; Replace and Reset Voltage Regulator Relays for DG-2	January 24
AP1527; Repair Plant Computer	February 2

No violations or deviations were identified.

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

The inspectors reviewed the following LERs associated with operating events. Based on the information provided in the report it was concluded that reporting requirements had been met, root causes had been identified, and corrective actions were appropriate. The below LERs are considered closed.

LER Number	Description
50-397/91-22	Shutdown Cooling Isolation
50-397/91-24	Main Steamline Break Outside Containment -- Unanalyzed Condition
50-397/91-27	Inadequate Jet Pump Surveillance Testing
50-397/91-36-01	Missed ASME Section XI Surveillance
50-397/91-41	Offsite Power Source Inoperable Due to Low Voltage
50-397/91-41-01	Offsite Power Source Inoperable Due to Low Voltage

The following LERs are closed based on the inspection performed and documented in NRC Special Inspection Report No. 50-397/91-44:

50-397/91-25-01	"A" Train of the Containment Atmosphere Control System Inoperable Due to Low Oil Level in the Recombiner Blower
50-397/91-29	Both Trains of Containment Atmosphere Control Systems Inoperable due to Recycle Flow Control Valve Deficiencies
50-397/91-29-01	Both Trains of Containment Atmosphere Control Systems Inoperable due to Recycle Flow Control Valve Deficiencies

No violations or deviations were identified.

11. <u>Exit Meeting</u>

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 March 15, 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 licensee did not identify as proprietary any of the information reviewed by or discussed with the inspectors during the inspection.