ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-397/95-05

License: NPF-21

Licensee: Washington Public Power Supply System
3000 George Washington Way
P.O. Box 968, MD 1023
Richland, Washington

Facility Name: Washington Nuclear Project-2 (WNP-2)

Inspection At: WNP-2 site near Richland, Washington

Inspection Conducted: January 22 through March 4, 1995

Inspectors: R. C. Barr, Senior Resident Inspector
D. L. Proulx, Resident Inspector
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Approved: Dwight D. Chamberlain 4-9-95
D. D. Chamberlain, Acting Chief, Project Branch E Date

Inspection Summary

Areas Inspected: Routine, announced inspection by resident and Region-based 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.

Results:

Operations

- Operator attention to detail did not appear to be sufficiently probing when the plant computer malfunctioned. This resulted in slightly exceeding the licensed full reactor thermal power level averaged over an 8-hour period. This matter will be addressed further in NRC Special Inspection Report 50-397/95-07.

- Operations personnel did not pay sufficient attention to detail in developing a clearance order associated with containment vacuum breaker position indication that resulted in an inadvertent entry into a Technical Specification (TS) action statement. This matter will be addressed further in NRC Special Inspection Report 50-397/95-07.

- Due to weakness in communications, the initial decision to continue lower power operation with high reactor coolant system (RCS) sulfate concentration appeared not to have fully considered safety risk. Subsequent deliberations by the licensee did consider short-term and long-term risk.

- Operators did not adequately self-check when pulling fuses for work associated with a vacuum breaker that resulted in electricians inadvertently working on energized equipment. This matter will be addressed further in NRC Special Inspection Report 50-397/95-07.

- Operators did not adequately self-check when performing turbine valve testing, resulting in a reactor scram. This matter will be addressed further in NRC Special Inspection Report 50-397/95-07.

- Operators responded well to two reactor scrams; however, the log keeping associated with the scrams was not timely.

- Operator self-checking and second verification was not adequate in hanging a clearance order associated with CAC-FCV-4A, resulting in the valve switch being in a different position than the danger tag required. This matter will be addressed further in NRC Special Inspection Report 50-397/95-07.

- Operators did not perform adequate reviews of the limiting condition for operation (LCO) or surveillance logs during plant startup. This matter will be addressed further in NRC Special Inspection Report 50-397/95-07.

- Configuration management of Valve SW-V-128A was inadequate. Valve SW-V-128 was not locked-sealed, indicating a partial loss of system status control. The valve was, however, in the correct position. This matter will be addressed further in NRC Special Inspection Report 50-397/95-07.

Maintenance

- The work instructions for setting spring tension on condensate filter demineralizer (CFD) septa were not of sufficient detail for craftsmen to correctly perform the task.

- Craftsmen self-checking on the corrective maintenance associated with a condensate resin trap was inadequate.

- Supervisory involvement in the corrective maintenance of the aforementioned resin trap precluded a potentially serious event.

- Surveillances observed were performed and documented properly.

Engineering

- The system engineer exhibited a strong questioning attitude in trending the performance of the scram discharge volume (SDV) vent and drain valves.
- The licensee does not include the opening times of the SDV vent and drain valves in the inservice testing (IST) program.
- A licensee engineer exhibited a strong questioning attitude in identifying an electrical separation deficiency with the reactor recirculation system (RRC) containment isolation valve modification.
- A modification implemented during a forced outage did not establish the correct electrical separation criteria, indicating that thoroughness in developing design change packages requires strengthening.
- The licensee's resolution of discrepant reactor building differential pressure (DP) sensor problems did not appear to be timely and resulted in the need for frequent workarounds by operations personnel.

Plant Support

- Housekeeping was very good in safety-related areas.
- Housekeeping in the CFD septa work area did not meet management expectations.
- Several personnel were observed wearing their electronic dosimetry in a manner not in accordance with licensee management's expectations.
- A number of emergency response pagers were inoperable for several months, raising questions about the adequacy of the testing methodology. The licensee took appropriate action to resolve the problem.
- Actions to correct high sulfate concentration in the reactor coolant system were not timely.

Summary of Inspection Findings:

- Violation 397/9414-01 (Paragraph 8.1) was reviewed and closed.
- Unresolved Item 397/9313-02 (Paragraph 8.2) was reviewed and closed.
- Licensee Event Report 397/94-08 (Paragraph 9.1) was reviewed and closed.
- Licensee Event Report 397/94-14 (Paragraph 9.2) was reviewed and closed.

Attachments:

- Attachment 1, Persons Contacted and Exit Meeting
- Attachment 2, Acronyms

DETAILS

1 PLANT STATUS

At the beginning of the inspection period, the plant was in Mode 1 (Power Operation) at 100 percent power. On January 26, 1995, the licensee exceeded their licensed thermal power level by less than 1 megawatt compared to the licensed power level of 3323 megawatts. On January 27, 1995, reactor power was reduced to 95 percent to conduct control rod scram timing tests and was returned to 100 percent on January 28.

On February 1, 1995, operators reduced reactor power to 60 percent because sulfates in the reactor exceeded 100 parts per billion (ppb). Following resolution of the sulfate excursion, reactor power was returned to 100 percent on February 5. On February 9, reactor power was reduced to 86 percent to troubleshoot high differential pressure across the condensate filter demineralizers and was returned to full power after resolution later that day.

On February 18, reactor power was reduced to 80 percent to conduct turbine valve testing. Later on February 18, due to operator error during turbine valve testing, the reactor scrammed. Following the scram, operators cooled down the reactor and entered Mode 4 (Cold Shutdown). Following completion of forced outage maintenance activities, the plant entered Mode 2 (Startup) on February 21. Operators heated the reactor and continued to increase reactor power until Mode 1 was entered on February 21. Power ascension continued until the plant achieved 100 percent power on February 25.

On February 26, the reactor scrammed from 100 percent power due to failure of a controller card in the digital electrohydraulic system. Operators cooled the reactor and Mode 4 was entered on February 27. Following completion of forced outage maintenance tasks, operators entered Mode 2 on February 28. Operators performed a reactor heatup and continued to increase power until Mode 1 was entered on March 1. Operators continued power ascension until 100 percent power was achieved on March 3. The plant was at 100 percent power at the end of the inspection period.

2 ONSITE FOLLOWUP TO EVENTS (93702)

2.1 Licensee Exceeded Licensed Power Level

On January 27, 1995, the licensee exceeded their licensed full reactor thermal power level averaged over an 8-hour period by less than 1 megawatt. The plant computer failed and was not providing proper indication of average reactor power for several hours during the shift. This condition went unnoticed by the operators until the relieving crew identified the error.
The licensee initiated Problem Evaluation Request (PER) 295-0052 to address this issue and propose corrective actions. The licensee reported this condition to the NRC regional office as required by the WNP-2 operating license.

This issue will be discussed further in NRC Special Inspection Report 50-397/95-07.

2.2 High Reactor Coolant System (RCS) Sulfates Due to Resin Intrusions

At WNP-2, the licensee monitors several major RCS chemistry parameters: conductivity, pH, chlorides, and sulfates. Other RCS impurities are also monitored and tracked. Plant Procedures Manual (PPM) 1.13.1, "Chemical Process Management and Control," Revision 14, integrates diverse portions of the Chemistry Program into a single document that provides guidance for chemistry and operations personnel and specifies limits, where applicable, and expected responses to some out-of-specification results.

The limits in PPM 1.13.1 are specified as Action Levels 1, 2, and 3 for conductivity, chlorides, and sulfates. Action Level 1 limits for the above parameters are 0.30 microsiemens (μS), 5 ppb, and 5 ppb, respectively. If one or more of these parameters exceed Action Level 1, the procedure directs that corrective action be taken as soon as practicable and a PER be initiated if not reduced below the action level within 96 hours. Action Level 2 limits for the above parameters are 1.0 μS, 20 ppb, and 20 ppb, respectively. If one or more of these parameters exceed Action Level 2, the procedure directs that corrective action be taken as soon as practicable and, if not reduced below the Level 2 action value within 24 hours, an orderly shutdown should be initiated. Action Level 3 limits for the above parameters are 5.0 μs, 100 ppb, and 100 ppb, respectively. If one or more of these parameters exceed Action Level 3, the procedure directs that an "orderly shutdown should be initiated immediately with reduction of coolant temperature to less than 100 degrees Celsius as rapidly as other plant constraints permit."

On January 31, 1995, at 10:18 p.m., operators noted that reactor power had decreased without flow change or rod movement and that reactor water conductivity had increased. At 11:06 p.m., operators entered Action Level 2 because RCS sulfates had reached 21.8 ppb. Operators initiated PER 295-0064, noting that the high sulfates were likely caused by placing a CFD on service. At 5:32 a.m., February 1, 1995, operators entered chemistry Action Level 1 for a conductivity of 0.317 μS. At 6:49 a.m., RCS sulfate level increased to 115 ppb, operators entered Action Level 3 and initiated PER 292-0065. At 6:54 a.m., operators reduced power to 1000 MW by decreasing flow. At 7:40 a.m., operators began reducing power to 75 percent. At 8 a.m., with the reactor at 75 percent power, RCS sulfate concentration reached 136 ppb, conductivity reached 0.476 μS, and pH had decreased to 7.02. At 10:05 a.m., due to the power decrease, RCS sulfates had decreased to 106 ppb. At 10:16 a.m., operators began reducing reactor power to 60 percent. At 12:31 p.m., operators exited Action Level 3 with conductivity at 0.293 μS, sulfates at 75 ppb, and chlorides less than 1 ppm. At 7:33 p.m., operators exited Action Level 2 when sulfates reached 20 ppb. At 8:25 a.m., on February 2, 1995, operators began increasing power to 100 percent when sulfates had reached a level of 7.2 ppb. At 1:10 p.m., operators exited Action Level 1. From this point to when the reactor reached 100 percent power, operators frequently entered and exited from Action Level 1, with

sulfates reaching values as high as 12.5 ppb. At 12:28 p.m., on February 5, 1995, the reactor achieved 100 percent power.

The inspector conducted followup of this event due to the effect that high RCS sulfate concentration can have on stress corrosion cracking (SCC) in stainless steel (SS) and the repeated number of resin intrusions that have resulted in high RCS sulfate concentration. The inspector reviewed plant logs, observed selected portions of the replacement of septa in several condensate filter demineralizers, attended several licensee meetings on this subject, spoke with the vendor representative for the CFD septa, and discussed the event with licensee engineers and managers.

The Electric Power Research Institute (EPRI) has performed a number of studies associated with SCC. These studies have characterized the effects of impurities in a boiling water reactor coolant system on SCC. One of the impurities evaluated was sulfate concentration. EPRI project interim Report 2293-1 noted that chloride in RCS water increased the crack rate initiation and propagation rates of SS in SCC, but less so than sulfates. In this document, EPRI noted that constant-extension-rate tests found that sulfates and chlorides at a fraction of a parts per million severely enhanced cracking of Type 304 SS. The report indicated that the effects of high sulfate concentrations are cumulative with respect to crack propagation. In the conclusions of the report, EPRI noted that with RCS sulfate concentrations of 25 to 100 ppb, crack propagation rates increase by a factor of 100.

The inspector first learned of the significant increase (Action Level 3) in RCS sulfates at 7:30 a.m., on February 1, 1995, during a conversation with the shift manager. The shift manager indicated that he was going to reduce power to 75 percent in the next 15 minutes.

The licensee met at 8:30 a.m., to discuss the resin intrusion. At the meeting it was noted that power had been reduced to 75 percent and that sulfate concentration had started to decline. The chemistry manager and chemistry support personnel indicated that they believed the high sulfate concentration was due to a combined resin intrusion and an organic intrusion. The Quality Assurance manager noted that plant procedures stated the reactor "should" be immediately shutdown if Action Level 3 values were exceeded. The group discussed the advantages of remaining operating and shutting down. The group's consensus was that continued reactor power operation was acceptable at lower power levels, since sulfate concentration was declining and removal of the sulfates would likely be more rapid at higher power levels.

At the conclusion of the meeting, the inspector expressed concern that the meeting had not addressed the near- and long-term safety risk of continuing power operation with high sulfates. The inspector was also concerned that the licensee's use of the term "should" in such situations does not clearly communicate management expectations and potential safety implications. The group decided to reconvene with metallurgical engineers to discuss the safety risk of continued power operation. The engineers noted that the probability of crack initiation would increase by a factor of three and that crack

propagation would be affected by a factor of 100. They pointed out that only one weld in the inservice inspection of RCS recirculation piping had a small indication and that the worst case projected growth rate for the crack was well within allowable values. The engineers concluded that continued power operation at reduced power was acceptable. The followup actions were discussed and the action plan to reduce sulfate concentration modified. The licensee will be conducting inservice inspection examinations during the refueling outage scheduled for April 1995, which will include piping and internal reactor vessel components, including the core shroud. These examinations should provide information to further assess the potential affects of the sulphate intrusions.

In PER 295-0064, the licensee concluded that the root cause of the resin intrusion was that the septa filter media had been damaged. The licensee identified the following major contributing causes: several nylon septa showed signs of shrinkage that were believed to be caused by drying out during CFD vessel inspection during Outage R9; improper septa spring pressure could have allowed septa to lift during high pressure air surges of backwash and precoat evolutions; and improper timer settings during the backwash and precoating evolutions. The licensee replaced all the septa in the three CFDs that appeared to be the major contributors to the resin intrusions and repaired leaking air valves. To further evaluate the resin intrusion, the licensee established 11 actions to further assess the need to change procedures or operations of the CFDs. None of these actions had been implemented by March 22, 1995. The inspector was concerned that the initial decision to continue power operation did not fully evaluate the near- or long-term risks of continued power operation and the apparent slowness to correct the resin intrusion problem. The plant manager indicated the intent to reevaluate corrective actions for these issues.

The inspector reviewed licensee logs and found that, since Refueling Outage R9, there had been greater than 15 resin intrusions that resulted in exceeding Action Level 1 sulfate levels. The inspector found that three of these intrusions exceeded the Action Level 2 value of greater than 20 ppb. The inspector noted that not until the event of February 1, 1995, had a detailed assessment of sulfate intrusions occurred.

The inspector observed selected portions of the replacement of the CFD D septa. During the replacement of the septa, the inspector observed that the craftsmen who were performing the work did not appear to be completely familiar with instructions for setting the spring tension of the CFD septa. The tension of the spring assures the proper preload of the septa into the nozzle at the base of the demineralizer. If the setting was incorrect, a potential for the septa to lift from the nozzle would exist. The inspector discussed this observation with the system engineer and the septa vendor. The vendor and the system engineer clarified the process to the craftsmen. The system engineer indicated that, during the removal of the septa, the spring tension values had been found to vary significantly and that many were found outside the vendor recommended value; however, none of the septa had been found outside their nozzle fitting. The inspector also observed that work

debris was located across the roped off contaminated area and, in general, the housekeeping in the area was poor. The inspector shared these concerns with the responsible health physics technician who corrected the problems.

The inspector discussed the decision to continue power operation with the chemistry manager, the operations manager, the plant manager, and the Vice President Nuclear Operations. From these conversations it appeared to the inspector that the near- or long-term risks had not been fully discussed at the time of the decision to continue operations at a lower power level. The conversations also did not appear to discuss the previous cumulative affects of operating at high sulfate levels. Subsequent licensee meetings determined that the near- term safety risk was very small and that the long-term risk was limited. The inspector considered that communications in making the decision could have been improved by involving Supply System metallurgical engineers early in the decision process to fully assess safety risk.

In summary, the inspector was concerned that the first decision to operate at lower power levels did not fully assess safety risk and corrective actions did not address the broader issue of timely corrective action for the previous sulfate intrusions.

2.3 Corrective Maintenance on Incorrect Resin Trap

On Saturday, February 11, 1995, operations authorized work on condensate demineralizer Resin Trap COND-RST-1D. A clearance order had been hung on the appropriate valves to isolate the resin trap. A team of three mechanics had been assigned to perform the work. Two of the individuals were to perform the work and a third individual, located outside the contaminated work area, was a runner. After the work had been started, the crew supervisor arrived at the work location and found that the craftsmen had started work on COND-RST-1E instead of Resin Trap COND-RST-1D. The supervisor directed the craftsmen to stop work. The supervisor was notified and PER 295-097 was initiated. An investigation was conducted.

The licensee found that the craftsmen had opened a vent plug on top of the resin trap to depressurize the trap. Water issued from the vent plug. The mechanics consulted with the equipment operator (EO) who hung the clearance to describe the water leakage from the vent. The EO did not observe the vent leakage. The crew supervisor arrived during this time and the group concluded that the vent leakage was residual pressure in the system. The supervisor directed that the craftsmen continue work by loosening the cover retaining bolts. The first bolt had been loosened when the crew supervisor recognized that the craftsmen had been working on the wrong resin trap. The supervisor directed the craftsmen to retorque the loosened bolt, then stopped work.

As corrective actions, the supervisor counselled the individuals, called a time-out for all mechanical work in progress, and planned to incorporate this event into a lessons-learned training program.

The inspector discussed this event with the acting maintenance manager and the crew supervisor, observed the labeling of components in the work area, and reviewed the PER. The inspector concurred with the licensee's root cause evaluation that the workers failed to adequately self-check. The inspector noted that the supervisor limited the significance of this error by being at the work site, observing the activity.

2.4 Incorrect Fuse Pulling in Support of Vacuum Breaker Task

On February 14, 1995, the licensee experienced two self-disclosing events of incorrect fuse pulling as discussed below.

2.4.1 Inadequate Clearance Order

On February 14, 1995, the licensee pulled the wrong fuses associated with repair of relays in Vacuum Breaker CVB-V-1EF. The clearance order incorrectly specified removing the fuses for the front disk indication of the vacuum breaker along with the rear disk indication. This caused an inadvertent entry into a TS action statement. The licensee initiated PER 295-0106 to document this issue. In addition, the licensee initiated an Incident Review Board (IRB) to gather the facts of the event and propose corrective actions. This issue will be further discussed in NRC Special Inspection Report 50-397/95-07.

2.4.2 Inadequate Fuse Verification

On February 14, 1995, operators pulled the wrong fuses associated with the repair of relays in Vacuum Breaker CVB-V-1EF. The operator failed to exhibit a strong questioning attitude, resulting in the error. The licensee initiated a PER. This issue will be further discussed in NRC Special Inspection Report 50-397/95-07.

2.5 Reactor Scram on Turbine Trip While Conducting Turbine Valve Testing

At 12:29 p.m., on February 18, 1995, while conducting turbine valve testing per PPM 2.5.7, "Main Turbine Generator," the reactor scrammed from 80 percent power due to a turbine trip. All safety systems functioned as designed. Control Rod 22-03 experienced a position indication "data fault" and did not indicate fully inserted. At 12:34 p.m., the shift engineer verified on the auto scram timer that Rod 22-03 had fully inserted. At 12:40 p.m., operators notified plant management of the reactor trip. Operators initiated a PER to document the scram and management established an IRB to collect facts associated with the scram.

The licensee proceeded to cold shutdown to correct a previously identified single failure concern with containment isolation valves in the hydraulic lines for the reactor recirculation flow control valves and to assess and correct leakage of the containment exhaust purge valves.

The IRB determined that the turbine tripped and the reactor scrammed because an EO had operated the turbine reset valve instead of the turbine test valve while conducting monthly turbine valve testing. The EO appeared to have failed to adequately self-check that he had selected the correct valve. A shift support supervisor who was supervising the EO was also involved in the test; however, the two had not established a routine for verifying that the proper equipment was selected prior to its operation. The two valves were labeled with metal tags and the surveillance procedure was clear on which valves were the test and reset valves.

At 1:45 p.m., the licensee notified the senior resident inspector of the reactor trip. The inspector responded to the site, observed control room activities, and observed the conduct of the IRB.

Upon arriving in the control room, the inspector noted that plant parameters had been stabilized following the reactor trip. The inspector verified that operators had completed the scram immediate and followup actions required by procedures. The inspector noted that, approximately 2.5 hours after the scram, the operators had not updated the control room log to contain the actions that had been performed during and following the reactor scram. The inspector noted that the operators had a rough log that they had been maintaining. When the operator transcribed the rough log to the control room log, the inspector noted that the sequence of the entries on the rough log was not exactly the sequence that had been transcribed to the control room log. The inspector considered that the operators were late in updating the control room log and could have more accurately transcribed the log. The inspector discussed this issue with the plant manager who took actions to address the inspector's concerns.

Additional inspection associated with this event will be documented in NRC Special Inspection Report 50-397/95-07.

2.6 Mode 4 to Mode 2 Transition

On February 21, 1995, the licensee transitioned from Mode 4 to Mode 2 with the Main Steam Leakage Control System inoperable. Instrument and control personnel backed out of a partial surveillance without restoring the system to its standby configuration. In addition, operators did not review the surveillance LCO log prior to operational mode transition. The licensee initiated PER 295-0128 to document this issue and to propose corrective actions. This issue will be further addressed in NRC Special Inspection Report 50-397/95-07.

2.7 Diesel Generator Automatic Starts

On February 22, 1995, at 5:47 p.m., the Division 1 and 2 diesel generators (DGs) automatically started due to a grid disturbance. The grid disturbance was caused by loss of the Priest Rapids line. The annunciator alarmed on an undervoltage of approximately 80 percent. The DGs did not load onto the emergency busses because the busses remained energized from offsite

power. The operators tripped the DGs shortly thereafter and restarted the DGs in idle for cooldown. At 7:02 p.m., the DGs were secured and returned to their normal standby lineup.

The licensee initiated PER 295-0133 to document this issue. The licensee performed a reportability evaluation and determined that this event was not reportable. The licensing organization stated that the WNP-2 Final Safety Analysis Report does not list the DGs as engineered safety features, therefore, this event did not constitute an ESF actuation. The inspector noted that NUREG 1022 states that several plants do not consider the DGs to be ESFs, but the NRC requests that these licensees submit DG starts as voluntary License Event Reports (LERs), so that the NRC can evaluate performance on a consistent basis. The licensee subsequently decided to submit voluntary LERs for events of this type involving DG starts.

2.8 Reactor Scram Due to Fast Governor Valve Closure

At 5:39 p.m., February 26, 1995, the WNP-2 reactor, which was at 100 percent power, scrammed as a result of high (flux) power as indicated by the average power range neutron monitors. The high power (119 percent) signal stemmed from a fast closure (approximately 2 seconds) of the turbine governor valves. A closure of these valves caused an increase in reactor pressure and power, resulting in a reactor scram. All safety systems functioned as designed.

Following the reactor trip, the main turbine experienced high vibration (19 mils) between 1200 to 1500 rpm. The licensee's initial assessment of the cause of the high vibration was that water backed up into main turbine seals because of the seal steam evaporator control system being in manual, as a result of an electronic failure in the level control system. The failure occurred during the startup on the February 21, 1995.

The licensee determined that the cause of the turbine governor valves' fast closure was that the valve limiter solid state control card, a printed circuit card in the digital electrohydraulic control system, failed. The licensee conferred with the turbine vendor and verified that the seal steam system in manual control could cause main turbine high vibration.

The senior resident inspector was notified of the reactor scram at 6:50 p.m., on February 26, 1995, and responded to the site. This issue will be discussed further in NRC Special Inspection Report 50-397/95-07.

3 PLANT OPERATIONS (71707, 92901)

3.1 Plant Tours

The inspectors toured the following plant areas:

- Reactor Building
- Primary Containment
- Control Room

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

3.2 Inspector Observations

3.2.1 Operating Logs and Records

The inspectors reviewed operating logs and records against TS and administrative control procedure requirements.

3.2.1.1 Improper Operational Mode Change

On February 22, 1995, while reviewing the control room operator's log, the inspectors identified that the licensee had entered Mode 1 (Power Operation) with one of the containment vacuum breakers indication inoperable. The inspectors notified the shift manager, who initiated PER 295-0136 to address this event. The inspectors were concerned because the licensee had previously transitioned from Mode 4 to Mode 2 with the Main Steam Leakage Control System inoperable, and the licensee had apparently not taken sufficiently effective or timely corrective action to control mode changes. The inspector noted that the licensee does not have a specific step in their plant startup procedure to perform reviews of the LCO or surveillance logs, but it would be expected that operators would make use of these logs.

In addition to the above concerns, the licensee performed reportability evaluations for the two TS 3.0.4 violations. The licensee determined that these events were not reportable in an LER. The inspector discussed this issue with the licensing manager. The licensee stated that the intent of the requirement in 10 CFR 50.73 that requires an LER for "operation that is prohibited by the Technical Specifications" was to report only violations of LCO action statements and not all violations of the TS. The licensee stated that a draft revision to NUREG 1022 implied this line of reasoning. The inspector noted that NUREG 1022 states that the licensees were not required to report administrative violations, such as violations of TS 6.8.1. However, the inspector noted that NUREG 1022 lists as an example of a reportable event as having fewer than the required number of licensed operators on shift. The inspector noted that this is not an LCO action statement violation that was considered reportable and, therefore, the licensee's rationale was not believed to be valid. The inspector concluded that the licensee's reportability evaluations did not appear conservative. This matter will be reviewed further during future inspections.

This issue will be discussed further in NRC Special Inspection Report 50-397/95-07.

3.2.2 Monitoring Instrumentation

The inspectors observed process instruments for correlation between channels and for conformance with TS requirements, and no discrepancies were identified.

3.2.3 Shift Manning

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. The inspectors concluded that shift manning was in conformance with the applicable requirements and operators were generally attentive to duties. The control room was observed to be free of distractions such as nonwork-related radios and reading materials.

3.2.4 Equipment Lineups

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.

3.2.5 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.

On February 8, 1995, during a walkdown of Clearance Order 95-02-005, the inspector noted that the control room switch for Valve CAC-FCV-4A was in the incorrect position as required by the danger tag. The valve switch was in the "AUTO" position, but the danger tag required the valve switch to be in the "CLOSED" position. The inspector notified the shift manager, who initiated a PER to address the issue. The shift manager cleared the tag on the switch, repositioned the switch to the "CLOSED" position, and rehung the danger tag.

The inspectors discussed this issue with the operations manager. The inspectors noted that this tag was hung by a licensed operator, but was second verified by an equipment operator. The inspectors noted that a number of recent self-disclosing or NRC identified issues have indicated that Operations' attention to detail and second verification have not been adequate. The inspectors noted that errors of this type were of concern because under different conditions a potential for personnel injury or equipment damage could result from tagout errors and that prompt and thorough corrective actions were necessary. The operations manager stated that this issue was not significant because the containment atmospheric control (CAC) system was already inoperable for maintenance and that fuses were also removed from the system, so the potential did not exist for equipment damage or

personnel injury. This issue will be discussed further in NRC Special Inspection Report 50-397/95-07.

3.2.6 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. No problems affecting system function were identified.

3.3 Engineered Safety Features Walkdown

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. 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	February 9, 15, 17
Low Pressure Coolant Injection Trains A, B, and C	February 6, 17
Low Pressure Core Spray	February 6
High Pressure Core Spray	February 6
Reactor Core Isolation Cooling	February 6
RHR Trains A and B	February 6, 17
Standby Gas Treatment	February 7, 15
Standby Liquid Control	February 7, 15
125V DC Electrical Distribution, Divisions 1 and 2	February 7, 17
250V DC Electrical Distribution	February 7, 17

3.3.1 Valve Not Locked Per Procedures

On February 7, 1995, the inspector found that Valve SW-V-128A was not lock-sealed in the throttled position. Valve SW-V-128A is a throttle valve that supplies cooling water to the CAC aftercooler. The lock-seal was broken and was near the valve handwheel. The inspector notified the shift manager, who initiated PER 295-0087.

Following notification of this deficiency, the licensee took immediate corrective action to verify proper valve position and place a new lock-seal on the valve. The licensee performed surveillance PPM 7.4.7.1.1.1, "Standby Service Water Loop A Valve Position Verification," and verified Valve SW-V-128A to be locked-sealed in its throttled position and found no additional discrepancies. To attempt to quickly identify the apparent root cause of this event, the licensee checked clearance orders and work orders, and found no documented evidence that the valve had been repositioned or the lock-seal cut. The licensee had performed no further investigative actions by the end of the inspection period.

The inspectors noted that on January 30, the licensee initiated a troubleshooting plan on Valve CAC-TCV-4A (a valve downstream of Valve SW-V-128A). Following the troubleshooting plan, the licensee effected repairs on Valve CAC-TCV-4A, per Work Order Task TF9101. When the maintenance was complete, the licensee performed surveillance procedures PPM 7.4.6.6.1E and 7.4.6.6.1.1, each of which verifies proper operation of the CAC system, including service water flows through the system. The inspectors also noted that the licensee had not conducted interviews with any of the personnel involved in performance of the troubleshooting, repair, or retesting of Valve CAC-TCV-4A. This issue will be discussed further in NRC Special Inspection Report 50-397/95-07.

3.3.2 Steam Leak in Reactor Core Isolation Cooling (RCIC) System

On February 6, 1995, the inspector found a steam leak on Valve RCIC-V-739. Valve RCIC-V-739 is an instrument root valve on the steam supply portion of the RCIC system. The valve had a steam plume of approximately 1 foot coming out of the packing of the valve. The inspector notified the shift manager, who informed the system engineer. Craftsmen attempted to tighten the packing of the valve and found that the packing was failed. Operators backseated the valve and the steam leak stopped. The system engineer initiated a work request to replace the packing and determined that the steam leak did not impact the operability of the RCIC system. The inspector discussed this observation with the plant manager and noted that better attention to detail by equipment operators and system engineers could have resulted in the licensee identifying the deficiency.

4 ONSITE ENGINEERING (37551, 92903)

The inspectors performed inspections of the following onsite engineering related activities during this inspection period:

4.1 Slow Response of SDV Vent and Drain Valves

On February 18, 1995, following the reactor scram discussed in paragraph 2 of this report, the SDV vent and drain valves were determined to have exhibited elevated times for opening. The system engineer, who was performing trending of these valves stroke times, identified that the opening times of the SDV valves had increased from the nominal time of approximately 5 seconds to 6 minutes. The draindown time of the SDV increased from the nominal time of 2 minutes to 6 minutes. The licensee initiated PER 294-0137 to document this issue and to propose corrective actions. The inspector was concerned that the SDV draindown system was degrading such that the ability to drain down the SDV and rescram the control rods, following an anticipated transient without scram scenario, would be delayed.

The inspector interviewed the system engineer concerning this event. The inspector concluded that the system engineer exhibited a strong questioning attitude in trending and identifying this issue. The system engineer noted that the nominal 5 second opening time for Valves CRD-V-181 and -11 was based on a design specification to prevent water hammer in the system. The system engineer found that this design specification was no longer applicable to WNP-2 because the configuration of the control rod drive system was different than that specified in the original design specification. Therefore, no specific timing requirement existed for reopening of the scram discharge vent and drain valves. The licensee did consider it important for the SDV vent and drain valves to reopen in a timely manner and will evaluate whether to develop acceptance criteria for the opening times of the SDV vent and drain valves.

TS 4.1.3.1.4.a requires the SDV vent and drain valves to be demonstrated operable by verifying that these valves close within 30 seconds of a scram and reopen when given a reset signal. Because there was not a TS time limit for the valves to reopen, the licensee did not have specific acceptance criteria for the SDV valve opening. The inspector reviewed the IST program for the facility and noted that the SDV valve opening time was not included in the program. The licensee stated that these valves did not perform a safety function in the open direction and, therefore, an acceptance criteria for opening time was not required. The inspector noted that the Emergency Operating Procedures took credit for timely reopening of the SDV vent and drain valves to drain the SDV and rescram the rods in an anticipated transient without scram scenario. The inspector also noted that, if the opening stroke times of the valves were tracked in the IST program, the licensee could initiate increased testing frequencies or corrective action if the stroke times exceeded certain thresholds. The inspector will further review the issue of including the SDV valves in the IST program in a future inspection period and the licensee indicated the intent to review this matter further.

4.2 Inadequate Design Change

On February 23, 1995, following completion of a design modification, the licensee initiated PER 295-0138 to address an electrical separation deficiency that resulted from the design change. This electrical separation deficiency

occurred as a result of implementing Basic Design Change (BDC) 94-0329-0. BDC 94-0329-0A was designed to eliminate a single failure possibility on RRC Hydraulic Line Isolation Valves HY-V-17A and -B, -18A and -B, -19A and -B, -20A and -B, -33A and -B, -34A and -B, -35A and -B, and -36A and -B. The licensee committed to resolve the single failure vulnerability during the next cold shutdown as corrective actions for a Notice of Enforcement Discretion that was issued for this problem in 1994. Although the single failure vulnerability was corrected, the licensee introduced a new deficiency (electrical separation) in implementing this BDC.

In development of the BDC, several spare conduits and cables were combined from both Division 1 and 2 to create the new required circuits. These circuits were located in relay cabinets E-CP-RC/1 and /2. The cables had been properly isolated using a technique called "siltemp" in the appropriate cabinets, but two flexible conduits, 1MISC-0454-001 and 2MISC-0453-002, were in physical contact with flex conduits of the opposite division.

The licensee's operability assessment stated that the equipment was degraded but operable. The deficient flexible conduits were located completely in the main control room floor area, and continued operability was allowed with implementation of compensatory actions, including a fire impairment in a continuously manned area until a modification could be implemented.

The inspector concluded that the engineer walking down the modification exhibited a strong questioning attitude in identifying the electrical separation deficiency. In addition, the inspector concluded that the licensee's compensatory and corrective actions were satisfactory to allow for continued operation. However, the inspector noted that several recent licensee and NRC identified issues have indicated a lack of thoroughness in the development of design change packages. The inspector discussed this issue with the Plant Manager, who stated that licensee long-term improvement programs already in place would continue to pursue improvements in engineering performance.

4.3 Problems with Reactor Building (Secondary Containment) Differential Pressure (DP)

The inspectors reviewed Engineering's evaluation and assessment of two issues involving reactor building (RB) DP. The first issue involved alarms associated with insufficient RB DP, operator workarounds required to deal with the alarms, and proposed modifications to resolve the problem. The second issue involved a recent event wherein insufficient RB DP was experienced for a brief period. Maintaining RB DP is important because the lower RB pressure provides the means of controlling and minimizing leakage from the primary containment to the outside atmosphere during a postulated loss of cooling accident and from the refueling facilities (including the spent fuel pool) during a postulated refueling accident.

The reactor building pressure control system for WNP-2 is designed to maintain a minimum negative pressure of at least 0.25" H_2O in the RB during normal and

emergency operations. Differential pressure is monitored by eight DP transmitters (four in each division), which measure DP between the inside of the RB at approximately the 572-foot elevation and the outside air on the four sides of the RB. These DPs are compared and the lowest value is used as the controlling signal. This signal is supplied to the RB DP controllers which maintain building pressure by adjusting the operating RB exhaust fan variable pitch suction vanes.

4.3.1 Reactor Building DP Alarms

Concerning the first issue, the inspectors reviewed a number of PERs which described situations where control room alarms or erratic DP readings indicated a degradation in DP between the RB and ambient air. PER 293-045 dated January 15, 1993, recognized that the control room alarms and erratic readings resulted from water blocking the small holes in the DP sensors which were exposed to the outside atmosphere. Water blockage occurred during rainy periods and during freezing weather when winds would envelope the RB in the cooling tower water vapor. Once a low pressure alarm or erratic reading would occur, the operators were instructed to shift DP control to the other division and to blow down the sensing lines on the side that was no longer controlling. The licensee's engineering group proposed modifications to the sensing lines, but at the time of the inspection, the proposed modifications had been delayed in favor of higher priority modifications.

The inspectors noted that, if the DP sensors become plugged, the failure mode is conservative in that a low pressure would be sensed. Furthermore, the operators had been instructed on restoration of RB DP by placing the DP controller in the manual mode and adjusting it manually from the control room to produce the desired flow.

The inspectors considered this first issue to be an example of a long-standing problem where operators had for years been forced to compensate for a system design deficiency with workarounds. The inspectors further noted that, for the 10-month period just prior to this inspection, the licensee had encountered problems with RB DP control room alarms and RB DP erratic readings more than 20 times. At the time of the inspection, the inspectors reviewed a proposed modification for the RB DP sensing probes, which the licensee was proposing to install within the year.

4.3.2 Reactor Building DP Outside of TS

The second issue involved a January 31, 1995, event in which RB DP decreased to negative 0.17 inch H_2O, which was outside of the TS RB DP limit of negative 0.25 inch H_2O. The degraded condition lasted for approximately 2 minutes.

The engineering group evaluated the condition and postulated that the condition was caused by abnormal wind conditions combined with slow RB DP controller response. Prior to the incident, the licensee had completed drywell ventilation. Drywell ventilation requires the standby gas treatment system (SGT) to be placed in service. When in service, the SGT also draws

down RB pressure, and the RB DP controller responds by cutting back on the RB exhaust. Approximately 15 minutes prior to the event, drywell ventilation was completed and the SGT was secured. Licensee meteorological records show significant increases in wind speed and changes in wind direction which could account for a rapid drop in ambient pressure. Engineering believed the RB DP controller was slow to respond, having not yet fully recuperated from compensating for the SGT which had been in service just prior to the event. The inspectors agreed that the cause of the event postulated by the engineering group was credible.

5 PLANT SUPPORT ACTIVITIES (71750)

The inspectors evaluated plant support activities based on observation of work activities, review of records, and facility tours. The inspectors noted the following during this evaluation.

5.1 Fire Protection

The inspectors observed firefighting equipment and controls for conformance with administrative procedures. Due to concerns with thermolag and fire seals, and because a number of fire doors were propped open to support work, the inspectors noted that a high number of fire impairments existed for which fire tours were being conducted.

5.2 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 several occasions during February 1995, the inspector noted that a number of individuals were wearing their electronic self-reading dosimeters improperly. General Employee Training and licensee procedures state that individuals should wear their thermoluminescent dosimeter (TLD) and self-reading dosimeters together at the chest. The inspector noted that maintenance, operations, and health physics personnel were wearing their TLDs in the proper location, but were wearing the self-reading dosimeters in their pants pockets, or at their side on their belts, and in one case in the back pocket.

The inspector notified the radiation protection monitor, who discussed this issue at the morning meeting to emphasize to plant supervision the need to ensure appropriate health physics practices are being utilized by plant personnel.

The inspector noted that these radiation detection devices were required to be worn together to preclude discrepancies between the two devices. If an individual wears them separated and works near a hot spot, the doses recorded by the TLD and electronic dosimetry may differ and yield an inaccurate dose assessment.

The inspector discussed these observations with the plant manager who stated that management will continue to emphasize the need for personnel to utilize appropriate health physics practices. The plant manager issued a memorandum to all employees to discuss this issue.

5.3 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 safety-related areas was generally very good during the inspection period.

5.4 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, that personnel allowed access to the protected area were badged and monitored, and that the monitoring equipment was functional. No problems were noted during these observations.

5.5 Emergency Planning

The inspectors toured the emergency operations facility, the Operations Support Center, and the Technical Support Center and ensured that these emergency facilities were in a state of readiness. Housekeeping was noted to be very good and all necessary equipment appeared to be functional, with the exception of the following observations.

5.5.1 Inoperable Emergency Response Pagers

On February 11, 1995, the licensee initiated PER 294-0109, indicating that a number of individuals on the roster for Emergency Response were carrying inoperable pagers. The PER stated that emergency planning (EP) management had received several complaints over several weeks of time that their pagers had not been working. These pagers had been inoperable despite a number of fully successful tests of the pagers over several months. The inspector was concerned that the licensee may not have been able to adequately respond to an emergency if a significant number of positions could not be filled due to inability to notify them.

The licensee's PER noted that a total of 35 personnel in the emercency response organization were carrying inoperable pagers. The following individuals were affected: 25 of 30 field team members, 3 of 5 electrical engineers, 3 of 5 core thermal engineers, 3 of 5 mechanical engineers, and 1 of 5 radiological emergency managers.

The inspector questioned the licensee on why they did not report this event per 10 CFR 50.72. 10 CFR 50.72(b)(1)(v) requires notification of the NRC within 1 hour via the emergency notification system for loss of emergency assessment, offsite response, or communications capability. The inspector noted that the failure to notify a significant number of people of an emergency could impair the ability to adequately man the emergency response facilities and, therefore, degrade their emergency assessment or offsite response capability. The licensee performed a reportability evaluation following discussions with the inspector. The licensee determined that this was not a significant degradation of the emergency plan and, therefore, was not reportable. The licensee noted that there was at least one individual carrying an operable pager for each position and also noted that, in the event that an individual does not respond to the beeper, the "autodialer" will call them at home to notify them of an event.

The inspector also questioned why the quarterly tests of the beepers did not catch this deficiency. The licensee stated that most of their testing of the beepers was done on day shift during normal working days. Just prior to the tests, the control room would announce, on the plant-wide intercom, that WNP-2 was conducting a test of the emergency response beepers. A significant percentage of the emergency response personnel would call in to acknowledge satisfactory performance of the test based on hearing the control room announcement, not on their beepers activating. The inspector determined that this appeared to be inadequate testing of the pagers and that the period of inoperability of the pagers was indeterminate and may have been a significant length of time.

The inspector discussed this issue with the EP Manager. The EP manager stated that the root cause of this issue was a modification to the software of the telecommunications system that caused the beepers in question to be inoperable. The licensee corrected the software problems in the telecommunications system. He also stated that the Supply System would conduct training and would consider testing the pagers during backshifts to get a more representative test for corrective actions.

5.6 Plant Chemistry

The inspectors reviewed chemical analyses and trend results for conformance with TS and administrative control procedures. Events involving RCS sulfite intrusion are discussed in Section 2.2 of this report.

5.7 Conclusions

Plant support performance was generally good during this inspection period. Personnel were observed wearing dosimetry improperly. Testing for operability of the emergency response pagers appeared to be inadequate to verify operability or identify problems. Security performance was very good during this period. The licensee's response to the resin intrusion appeared to correct the problem, but the solution was not viewed by the inspectors as initially being formulated in a methodical manner.

6 SURVEILLANCE TESTING (61726)

The inspectors reviewed surveillance tests required to be performed by the 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 tests on the dates shown:

Procedure	Description	Dates Performed
7.4.8.1.1.2.12	High Pressure Core Spray (HPCS) Diesel Test	February 13
7.4.3.2.1.80	RCIC Steam Supply High Flow CFT - CC	March 1

The inspectors concluded that these surveillances were performed and documented properly.

7 MAINTENANCE OBSERVATIONS (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 quality assurance/quality control involvement, proper use of clearance tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting.

The inspectors witnessed portions of the following maintenance activities:

Description	Dates Performed
HH6210 Blow Out Reactor Building Sensing Lines	February 17

Repair Battery Charger C2-1	February 28
CFD Septa Replacement	February 4

The inspectors determined that these maintenance activities were performed and documented properly. Inspector observations on the replacement of CFD septa is documented in paragraph 2.2.

8 FOLLOWUP (92901, 92902, 92903, 92904)

The inspectors reviewed records, interviewed personnel, and inspected plant conditions relative to licensee actions in response to previous open items.

8.1 (Closed) Violation 397/9414-01: "Inadequate Corrective Action on Recirculation Valve"

This violation involved the licensee's failure to adequately correct the erratic operation of an RRC flow control valve (FCV) (RRC-FCV-60A). The erratic operation of the FCV throttled position was not significant during full power, full flow conditions, because small changes in the valve's throttled position do not significantly affect reactor core flow when the valve is near its full open position. However, at 50 percent power, the condition of the plant on April 26, 1994, the erratic operation of the RRC FCV caused significant changes in core flow and reactor power fluctuations which prompted the licensee's operators to manually scram the reactor. Details of the circumstances of this event were discussed in LER 397/94-008, Revision 0, which was also reviewed and closed during this report period. (Refer to Section 9 of this inspection report.)

The licensee identified degraded position Transmitter RRC-POT-26A as the root cause for the erratic operation of Valve RRC-FCV-60A. The licensee had previously identified the problem on August 16, 1993. At that time, as an interim measure until the position indicator was replaced, the licensee system engineer recommended that the valve be "locked up" once it was placed in its desired position. Operating Procedure PPM 2.2.1, "Reactor Recirculation System," was revised to incorporate the recommendation. However, the valve was not "locked up" at the time of the event. According to the licensee, a secondary cause of this event was that PPM 2.2.1 was not clear as to when to "lock up" the degraded valve, because neither the system engineer who made the recommendation for the procedure change nor anyone else from plant technical personnel was involved in the concurrence process to assure that their recommendation had been appropriately included and clearly worded.

The inspectors verified that the licensee had completed the following corrective actions:

(1) The position transmitters for Valve RRC-FCV-60A and similar Valve RRC-FCV-60B were replaced and successfully tested to verify proper operation.

(2) The associated LER, LER 397/94-008, was required as mandatory reading for

WNP-2's licensed operators and documentation was provided as evidence that this had been accomplished.

(3) Operations Instruction 12, "Operational Cycle Concerns," added a section to address "Procedure Deviation for Inop/Malfunctioning Equipment." In referring to malfunctioning equipment that must remain in use and requires a procedure change to do so, Operations Instruction 12 now requires that: "A procedure change to address inoperative or malfunctioning equipment must have plant technical concurrence prior to implementation."

The inspectors considered that the corrective actions addressed the postulated root causes of the violation and that the corrective actions had been accomplished.

8.2 (Closed) Unresolved Item 93-13-02: Leaking HPCS Flange

During a walkdown of the HPCS system on May 3, 1993, an NRC inspector found a flange on a Restriction Orifice (HPCS-RO-06) on the HPCS pump minimum flow line leaking at the rate of about 20 drops per minute. The flange of the orifice constitutes a portion of the containment boundary. A concern of the inspector was that the flange was not isolable from the containment. The licensee stated they would evaluate the deficiency.

The inspector reviewed the licensee evaluation of the leakage from the flange. The licensee evaluated the leakage from the viewpoint of an HPCS leak and did not aggressively pursue the containment integrity issue. The inspector found the analysis of the leakage from the flange, relative to the allowable leakage in the HPCS system, to be thorough in determining the leakage to be of low significance. However, the inspector determined that the licensee's analysis of the leak and it's effect on containment integrity was lacking in depth. Specifically, the licensee did not make an attempt to determine how the leakage would contribute to the overall containment leak rate. Following a discussion of this issue, the licensee staff provided the inspector an analysis which determined that the leakage was within the projected overall containment leak rate (L_a). The inspector concluded that the leakage was minor and did not significantly contribute to the overall containment leakage rate.

9 REVIEW OF LERs (90712, 92700)

During this inspection period, the inspectors reviewed the following LERs associated with operating events.

9.1 (Closed) LER 397/94-08, Revision 0: "Manual SCRAM Due to Observed Reactor Core Power Fluctuations"

This LER concerned an April 26, 1994, manual SCRAM due to observed reactor core power fluctuations. The cause of the SCRAM was a faulty RRC FCV position transmitter and procedures which were not sufficiently clear as to when to

lock up the degraded valve to keep it from "hunting" (i.e., to keep it from making small changes in its throttled position).

The licensee's corrective actions included:

(1) replacement of the faulty RRC FCV position transmitters,

(2) calibration testing of the replacement FCV position transmitters, and

(3) required reading of LER 397/94-008 by the WNP-2 licensed operators.

The inspectors reviewed the LER and considered the corrective actions to be appropriate to the circumstances. The inspectors verified that the corrective actions had been accomplished.

9.2 <u>(Closed) LER 397/94-14, Revision 0: Engineered Safety Feature Actuation Due to Test Lineup Error Caused by Noncompliance with Testing Procedure</u>

The inspector performed an in-office review of this LER and noted that it contained a satisfactory description of the event, and the root causes and corrective actions were identified and appeared appropriate.

ATTACHMENT 1

1 PERSONS CONTACTED

Washington Public Power Supply System

*V. Parrish, Vice President Nuclear Operations
*J. Burn, Engineering Director
*G. Smith, Quality Assurance Director
P. Bemis, Regulatory and Industry Affairs Director
*J. Swailes, Plant General Manager
*M. Reddemann, Technical Services Division Manager
*C. Schwarz, Operations Manager
*T. Love, Chemistry Manager
*R. Barbee, System Engineering Manager
J. Albers, Radiation Protection Manager
*D. Swank, Licensing Manager
*J. Muth, Plant Assessments Manager
*M. Nolan, Radwaste Supervisor
*N. Zimmerman, BOP Technical Services Supervisor
*M. Monopoli, Maintenance Specialist
*R. Utter, Emergency Planner
*A. Barber, Senior Quality Assurance Engineer
*M. Hedges, Corporate Chemist
*J. Pedro, Licensing Engineer

Bonneville Power Administration

*D. Williams, Nuclear Engineer

U.S. Nuclear Regulatory Commission

*D. Chamberlain, Chief, Project Branch E
*J. Clifford, Senior Project Manager, Office of Nuclear Reactor Regulation
*R. Barr, Senior Resident Inspector
*D. Proulx, Resident Inspector

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 March 16, 1995.

2 EXIT MEETING

An exit meeting was conducted on March 16, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspectors' findings. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

ACRONYMS

BDC	basic design change
CAC	containment atmospheric control
CFD	condensate filter demineralizer
DP	differential pressure
DG	diesel generator
EO	equipment operator
EP	Emergency Planning
EPRI	Electric Power Research Institute
ESF	engineered safety feature
FCV	flow control valve
HPCS	high pressure core spray
IRB	Incident Review Board
IST	inservice testing
LER	licensee event report
LCO	limiting condition for operation
NRC	U.S. Nuclear Regulatory Commission
PER	problem evaluation request
ppb	parts per billion
PPM	plant procedures manual
RB	reactor building
RCIC	reactor core isolation cooling
RCS	reactor cooling system
RRC	reactor recirculation system
SCC	stress corrosion cracking
SDV	scram discharge volume
SGT	standby gas treatment
SS	stainless steel
TLD	thermoluminescent dosimeter
TS	Technical Specifications
WNP-2	Washington Nuclear Power Supply System, Unit 2