ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-397/95-33

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

Inspection At: WNP-2 site near Richland, Washington

Inspection Conducted: November 26, 1995 through January 6, 1996

Inspectors: R. C. Barr, Senior Resident Inspector
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Approved: H. J. Wong, Chief, Reactor Projects Branch E — 1/31/96 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, and licensee event reports.

Results:

Operations

- The threshold for reporting and documenting potentially degraded or degraded equipment appeared high, as evidenced by equipment operator awareness of a leaking diesel generator gasket and equipment operator and shift support supervisor awareness of an unusual noise when starting the service water system (later determined to be water hammer), without documenting these as problems (Sections 3.2.1.2 and 4.1.1.2).

- While the general quality and thoroughness of shift turnovers improved from past observations, three instances of poor three-way communications were observed (Section 3.2.2).

- Based on quality assessment findings, licensee management increased oversight of the Gold Card program and provided an individual to be responsible for assuring deficiencies were properly documented in the Problem Evaluation Report program.

Engineering

- Troubleshooting to determine the cause of Diesel Generator 1's failure to start properly was generally thorough and well thought out and interorganizational communications were effective, representing improved troubleshooting and communications (Section 2.1).

- Troubleshooting associated with the lifting of a diesel air start relief valve was poor in that it was based on an assumption of the problem instead of a thorough diagnostic assessment of the problem (Section 3.2.1.1).

- Licensee investigation into a water hammer identified by an NRC inspector in Loop B of the service water system was slow (Section 4.1.1.2).

- Licensee identification and assessment of a reactor core isolation cooling pipe support that had been partially pulled from the wall due to a number of low order water hammer events was good (Section 4.3).

- Management oversight of the interdisciplinary walkdowns process requires strengthening. To date since 1993, the licensee has performed only 15 of 57 targeted systems' walkdowns (Section 4.4).

Maintenance

- Surveillance testing was generally performed and documented properly. One minor procedure nonadherence was identified that did not impact safety (Section 5).

- Maintenance tasks were generally performed and documented properly. One instance of weak work planning was identified (Sections 6.1 and 6.4).

- The material condition of the reactor closed cooling system pumps, heat exchangers, and associated piping appeared somewhat degraded (Section 7.3).

Plant Support

- Housekeeping was observed to be good with the exception of the solid radiological waste and hot metallurgical laboratory areas (Section 7.3).
- The chemistry index for reactor coolant for the last two inspection periods has been 1.0, indicating excellent reactor water chemistry (Section 7.6).
- The licensee identified the need for improved accountability of special nuclear material (Section 7.7).

Summary of Inspection Findings:

New Items

- Inspector Followup Item 397/9533-01 (Section 4.1) was opened.
- A noncited violation was identified in Section 5.1.

Closed Items

- Unresolved Item 397/9306-06 (Section 8.2) was closed.
- Inspector Followup Item 397/9429-03 (Section 8.1) was closed.

Attachments:

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

DETAILS

1 PLANT STATUS

The plant was at 97.5 percent reactor power at the beginning of the inspection period due to testing that indicated slightly elevated feedwater flow. From November 26 through December 7, the Supply System varied reactor power between 97.5 and 60 percent power periodically, due to excess electrical generation capacity in the Northwest. From December 7 through December 27, the reactor power remained at 60 percent power. On December 21, as a result of the licensee's testing and analyses of feedwater flow, the licensee adjusted the gain of nuclear instruments such that power increased by 1.24 percent. On December 27, power was increased to 100 percent for the remainder of the inspection period.

2 ONSITE FOLLOWUP TO EVENTS (93702)

2.1 Emergency Diesel Generator (DG) 1 Electronic Speed Controller Failure

Background - WNP-2 has three emergency DGs. DG1 and DG2 provide emergency electrical power to various 4160 V components. DG3 provides emergency electrical power to the high pressure core spray (HPCS) system and associated components. DG1 and DG2 use a Woodward electronic loadsharing and speed control system (9905 Series) to maintain desired speed under load changes. For redundancy, DG1 and DG2 have a mechanical governor control system to control the speed of the diesel should the electronic governor fail. Normal operation of DG1 and DG2 is controlled by the electronic governor. During DG startup, the electronic governor accelerates the DGs to 450 rpm and subsequently increases engine speed to 900 rpm.

2.1.1 Failure of DG1 to Accelerate to Idle Speed

On December 17, during postmaintenance and surveillance testing, DG1 unexpectedly accelerated to 940 rpm instead of 450 rpm during startup. At 8:06 p.m., licensed operators declared DG1 inoperable and entered Technical Specification (TS) Limiting Conditions for Operation (LCOs) 3.8.1.1.a and 3.8.1.1.d. These LCOs required the licensee demonstrate and verify the operability of the remaining AC power sources by performing certain surveillance tests. The surveillance tests included verifying the availability of offsite power and periodically starting the remaining emergency diesel generators to verify their operability. The licensee successfully conducted the initial surveillance tests.

On December 19, 1995, the licensee requested that NRC exercise discretion to not enforce compliance with the actions required in TS 3.8.1.1.a for continued testing of emergency DGs (DG2 and DG3) every 8 hours in accordance with Surveillance Requirement 4.8.1.1.2.a.4. The licensee requested enforcement discretion to eliminate unnecessary wear of DG2 and DG3. This had been previously identified by the industry and the NRC in NUREG 1434 as excessive testing. The licensee concluded that the elimination of the additional testing increased overall plant safety with no identified negative consequences. On December 19, the NRC approved the licensee's request for enforcement discretion.

The licensee developed a troubleshooting plan and determined that the Woodward electronic loadsharing and speed control system had failed. Further licensee investigation found that a capacitor had failed in the power supply of the electronic speed controller. On December 19, the licensee replaced the electronic governor and conducted the appropriate postmaintenance and surveillance testing. At 2:22 a.m. on December 20, the licensee declared DG1 operable and exited the conditions of the enforcement discretion.

2.1.2 NRC Inspection

The inspector evaluated the licensee's troubleshooting plan, interorganizational communications, request for enforcement discretion, and previous related events. The inspector concluded that generally the licensee's troubleshooting plan was of appropriate detail to determine the cause of the failure of DG1 to start and that the licensee's interorganizational communication in resolving this issue was generally effective. The inspector considered the licensee's request for enforcement discretion to be adequate; however, the inspector noted the licensee's weak knowledge of the changes to the enforcement discretion process.

With respect to the review of previous similar events, the inspector noted that on June 12, 1994, DG2 experienced the same failure as occurred to DG1 on December 17, 1995. The licensee stated that replacement of the DG1 electronic loadsharing and speed controller was planned during the 1995 refueling outage (R10), but did not take place due to outage schedule concerns. Licensee management deferred the replacement to the 1996 refueling outage (R11). The licensee considered the deferral acceptable because the mean-life of this type of electrolytic capacitor was approximately 10 years (this capacitor had been in service for at least 11 years), frequent surveillance testing would detect the failure of this capacitor, and the DG would be able to perform its safety function on the mechanical governor. The inspector concluded that the licensee's decision to defer the replacement of the electronic controller was acceptable based on DG1's ability to perform its safety function on the mechanical governor. However, their basis for not replacing the governor due to capacitor mean-life was based on accepting the risk that the electronic governor could fail. Based on the ability of diesel generator to properly function using the mechanical governor and that a management decision based on associated risks was made by the licensee, enforcement action was not considered appropriate.

2.1.3 Conclusions

The licensee's troubleshooting plan to determine the cause of DG1's failure to start properly was generally thorough and well thought out. Licensee interorganizational communication was effective during this event, representing improved communications from previous events. The licensee's enforcement discretion process had not been updated to reflect the changes published by NRC Administrative Letter 95-05, "Revisions to Staff Guidance for Implementing NRC Policy on Notices of Enforcement Discretion," on November 7, 1995. This process problem delayed issuance of the NOED, but did not impact safety decisions.

3 PLANT OPERATIONS (71707, 92901)

3.1 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
- Diesel Fire Pump Room

3.2 Inspectors' Observations

3.2.1 DG Room Tours

3.2.1.1 Emergency DG Air Start System Relief Valve

On November 28, 1995, during a tour of the emergency DG building, the inspector identified that Relief Valve DSA-RV-2B, the nonsafety-related common relief valve for the air compressor in the DG2 air start system, was lifting as the lead compressor was charging the diesel air receivers. The inspectors noted that the discharge pressure of the compressor was approximately 275 psi. Control room operators indicated that DG2 remained operable as starting air pressure was sufficient to meet TS requirements of 230 psi.

The licensee then replaced the relief valve because they suspected that the relief valve setpoint had drifted (since the relief valve had a soft seat which may have deformed, causing a change in spring tension and setpoint drift) and a replacement was readily available. The licensee's assumption differed from the inspectors' observation, since the relief valve appeared to be lifting at or near its set pressure. Upon replacement and postmaintenance testing, the replacement relief valve again lifted. The licensee subsequently determined the lift setpoint of the original relief valve to be 265 psi.

Further licensee investigation determined that there was blockage downstream of the relief valve in the air drying section of the starting air system. Licensee investigation found that the desiccant in the lower section of the

desiccant bed was clumped together, blocking the air flow and resulting in the elevated system pressure which caused the relief valve to lift. Clumping of the desiccant had been previously identified during testing of the air dryer after its replacement. To resolve clumping of the desiccant, the licensee implemented a preventive maintenance task for an equipment operator to periodically stir the desiccant. Based on this event, the licensee determined that this preventive maintenance task had not been adequate to prevent desiccant clumping. As corrective action based on vendor recommendation, the licensee plans to place marbles in the lower portion of the desiccant to prevent clumping of the desiccant.

From inspection associated with this event, the inspectors concluded that the replacement of the relief valve without a thorough diagnostic assessment of the reason the relief valve had lifted was an example of poor troubleshooting. In this instance, the licensee assumed they knew what the failure had been without thoroughly evaluating the alternative causes for the relief valve lifting. The licensee had no history of this soft-seated valve deforming and resulting in a change of setpoint. Testing of the relief valve prior to replacing the valve would have identified only a 10 pound change in its setpoint which would be expected for a soft-seated valve that had lifted and reset recently.

The licensee stated that this problem, which was a repeat problem, was a commercial issue that could be appropriately addressed by the system engineer as part of a long-term system improvement plan. The inspector agreed that this relief valve was not safety-related, but the inspector noted, however, that the clumping of the desiccant was a repeat problem and that failure of the relief valve could prevent the diesel air receivers, which are safety equipment, from being charged. Therefore, it appeared prudent to document this recurring problem to assure the root cause and corrective action would be adequate to prevent additional recurrences.

3.2.1.2 Leaking DG Gasket

On December 28 and 30, 1995, the inspector toured the DG rooms. The general material condition of the equipment was good, but there were a number of oil leaks noted (especially after a diesel run) around the upper lube oil gasket seals. The equipment operator was aware of the leaks and indicated that the leaks were "normal" and were usually wiped up after a diesel run. While the existing leak rate appeared not to be severe enough to affect the operability of the DG engine, the inspector was concerned that an increased degradation of the gasket seals may affect the engine's operability. On December 28, licensee compliance personnel indicated that the leakage rate had increased slightly and that replacement gaskets had been ordered.

The inspectors expressed concerns to licensee operations management that the threshold for equipment operators to report deficient or degraded equipment might be below management expectations. Licensee management agreed with this observation and stated that human performance issues and expectations were being addressed at all levels of the organization and were of the highest priority.

3.2.2 Operating Logs, Records and Control Room Observations

The inspectors observed that the control room operators were generally attentive to plant parameters and conditions. The reactor operators (ROs) were observed to silence alarms, announce alarms, check condition and, after referring to the alarm response procedure following initial receipt of the alarms, periodically referred to the alarm response procedures.

The inspectors reviewed operating logs and records against TS and administrative control procedure requirements. The inspectors noted the licensee changed from hand-written logs to electronic logs. This transition appears to have been effectively implemented. Operator maintenance of the logs appeared acceptable.

The inspectors observed a number of shift turnovers. Generally, the quality and thoroughness of shift turnovers improved from past observations. The inspectors observed that each offgoing crew member reviewed the previous shift activities with the oncoming crew member. The reviews included discussion of logs, work orders, and night orders. While walking down the control room panels, the crew members examined pertinent tags, noted unusual or important indications, and discussed ongoing evolutions. The inspectors determined that the watchstander turnover activities appeared adequate. Following the individual watchstander turnovers and watch turnover, the control room supervisor (CRS) briefed the crew on planned activities and abnormal equipment lineups for the shift. Other watchstanders were then called upon to present pertinent information that they had learned through their individual turnovers. This evolution was supervised by the shift manager (SM), who also outlined the planned evolutions expected during the shift. Shift equipment operators and the duty shift engineer were also present during this meeting.

The inspector assessed the effectiveness of control room operator communications. The inspectors concluded that communications had generally improved. However, the inspectors observed on three separate occasions inadequate three-way communications in that the CRS (or his representative) did not acknowledge the RO's announcement of alarms. The SM informed the inspector that either the lead RO, or, in the lead RO's absence, the CRS, is responsible for acknowledgement and oversight of alarm conditions. The SM stated that he would discuss these observations with the control room crew.

During a control board walkdown, inspectors noted a large number of white control room indication deficiency stickers on balance of plant instrumentation, some dating from July 1995. The inspector discussed the number of deficiencies with the operations manager who stated that the situation did not meet his expectations and that a new program to track, prioritize repair, and reduce the backlog of inaccurate control room indication had recently been implemented. The operations department has

assigned a shift technical advisor duties to assist maintenance in tracking and prioritizing the repair of control room deficiencies. The inspector noted that the deficiency backlog was trending downward at a consistent rate.

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.

3.2.4 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. Appropriate entry into TS LCO was verified by direct observation.

3.2.5 Equipment Tagging

The inspectors observed selected equipment for which tagging requests had been initiated and verified that tags were in place and the equipment was in the condition specified.

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 anomalies 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 selected portions of the following systems:

Diesel Generator, Division 1 and 2
Low Pressure Coolant Injection Train B and C

High Pressure Core Spray
Standby Gas Treatment Train B
Standby Liquid Control
Standby Service Water System Train A and B
125-Vdc Electrical Distribution, Division 2
250-Vdc Electrical Distribution

The inspectors noted that the engineered safety features (ESF) systems were generally in good material condition and were aligned in accordance with applicable licensee procedures for the portions of the systems walked down.

4 ONSITE ENGINEERING (37551, 92903)

4.1 Service Water (SW) System

Background - Within the last 3 years the licensee has experienced problems with biofouling. During this time, the licensee has introduced chemical agents to the SW in an effort to reduce biofouling. Leaks have recently been identified in the SW; and additional dynamic loads, which had not been considered in the original design analysis, have also been identified. The inspector was concerned because a break in the SW could cause flooding and a loss of cooling capability. This was identified in the licensee's Individual Plant Examination Probabilistic Risk Assessment to be a major contributor to core damage frequency.

4.1.1 Leaks in the Service Water System

On November 29, 1995, an NRC inspector and a licensee equipment operator identified a leak near the high point of the service water line Loop B. A stream of water was spraying from the leak onto an adjacent motor control center (MCC). The licensee initiated a problem evaluation request (PER). The initial evaluation conservatively concluded the line to be inoperable. The licensee cleaned and checked the affected MCC and restarted the SW pump in order to assure the MCC was adequately protected. Precautions included erecting a shield around the pipe with a drain system to carry away the leaking water. The licensee determined that the leak was from a pinhole in the center of a 3/4-inch pipe nipple to sockolet.

The licensee removed the flawed section from the piping in order to perform destructive examinations to determine the cause and type of failure. Initial results of the evaluation indicated that the pinhole leak had resulted from bio-induced corrosion which had caused a pit to initiate from the inside of the pipe wall at the crevice formed by the joining of the sockolet connection. (Proper welding of sockolet fittings requires that the male end of the fitting be inserted with a small gap between its end and the receptacle shelf of the female end.) The licensee noted that the piping in the failed location was sometimes wetted by the SW and sometimes exposed to the air inside the pipe. The area of pitting was confined along only a few degrees of the circumference of the pipe and along a very short distance of the pipe's axis. Although the flaw had caused a leak in the pipe, it would not have been a significant impact on its structural integrity. The licensee concluded that the type of flaw which had caused the pinhole leak would likely be detected by observing a leak well before any break would occur.

The inspectors noted that in late 1995 a leak was observed on the 18-inch SW recirculation line near one of the SW pumps. The inspectors questioned licensee personnel about their investigation of that leak and if any similarity existed between the leak in the 18-inch line near the bottom of the SW system and the leak on the small bore SW line near the top of the SW system. The licensee explained that investigation of the leaks and the cause of the failure was still ongoing. Nondestructive examination of the piping at the 18-inch line and the adjacent piping did not reveal any overall pipe wall thinning, but did identify flaws similar to those in the small bore line, i.e., the flaws seemed to be in the form of pits confined to a few degrees along the pipe circumference and a small distance (apparently less then a 1/4 inch) along the pipe's axis. The flaw on the 18-inch line occurred at approximately the 4 o'clock location along the pipe circumference. A drain line entered the line near the location of the flaw. It was noted that the location of the flaw, and proximity of the drain line, subjected the 18-inch line at the flaw location to the same type of wetting and drying action which was present at the flaw on the small bore piping near the top of the SW system. As with the small bore pipe flaw, the identified leak did not appear to pose any threat to the structural integrity of the pipe. As such it appeared that any flaw would first be detected as a leak well before any catastrophic break could occur.

The inspectors inquired about the various chemicals introduced in recent years to combat biofouling. The licensee indicated that they had performed extensive research before introducing the chemicals. For example, chlorides, which would have been the best means of fighting biofouling, were not used because of the susceptibility of the SW piping to chloride-induced stress corrosion cracking. At the time of the inspection, the scope of the licensee's studies indicated that the corrosion was likely biologically induced.

The licensee was planning to remove a section from the 18-inch SW recirculation line during the next refueling outage to determine the cause of the pinhole leak in that section of piping. The licensee anticipated that at that time a more accurate determination of the flaw type, failure mechanism, and any similarity with the small bore line failure could be determined, and appropriate corrective actions could be devised. The licensee's further evaluation of the type of flaw, root cause, and corrective actions will be reviewed by the inspectors as a followup item.

4.1.2 Service Water System Water Hammer

As part of the troubleshooting associated with the SW pinhole leak, on November 29, 1995, an NRC inspector, along with licensee personnel that included equipment operators, the system engineer, and the shift support

supervisor, observed the restart of the SW line Loop B. The observers heard a bang in the system, which the inspector characterized to the licensee as an apparent water hammer.

In followup to this observation, another NRC inspector noted that no formal documentation, such as a PER, had been initiated. Based on discussions with several licensee personnel, including the observers of the event, the inspector noted that the licensee had not initiated the PER because they viewed the bang as a normal occurrence during startup of the SW system. The licensee informed the inspector that a startup of the SW would be performed on December 12, 1995, to investigate the bang. The inspector and licensee personnel including the system engineer and a representative from the licensee's piping stress analysis group observed the performance of the system startup and noted a loud bang. The licensee then initiated a PER for evaluation of the event. The system engineer noted that the bang observed on December 12 was significantly louder than that which was observed on November 29, possibly because on November 29, the SW may not have drained to the extent it would had it been in standby for a long period. The inspector considered that the licensee had not been timely in initially evaluating the bang in the SW line Loop B. It appeared that the willingness of the licensee to initially accept the noise in the SW may, in part, have been a consequence of not fully considering the extent of SW draindown on startup loads and not initially involving the pipe stress analysis group.

The recommended corrective action of the PER stated, "Perform field testing and/or analysis to quantify the startup forces exerted on the system piping in this area and address the impact on allowable stresses." The inspectors agreed that the loads associated with the bang needed to be quantified and evaluated. After review of the licensee's current stress analysis of the SW system, the inspectors noted that significant stress margins were available. The inspectors also noted that movement of the SW line during the noise was small and that the licensee's examination of the SW restraints and piping following the bang found no evidence of damage. For these reasons, the inspectors did not consider SW operability to be an immediate concern.

As part of the evaluation of the SW system for water hammer, the licensee also performed a startup of the SW line Loop A. The licensee noted a bang in Loop A, but of a lower magnitude than that of Loop B. Further investigation by the licensee identified a difference in opening times for the butterfly valves which control service water flow at the initiation of SW system startup. The control circuitry of the butterfly valves limits their opening during the initial seconds of system startup in order to limit the initial flow of water and to soften its impact on the partially voided SW system. In the case of Loop A, the initial flowrate was limited through the butterfly flow control valve to about 10 seconds longer than that of its counterpart on Loop B, which the licensee believes may be contributing to the magnitude of the water hammer. The licensee was in the process of investigating to determine the optimal flow initiation characteristics for the SW flow control valves. Any changes in valve opening times would require changes to the valve control circuitry and accompanying evaluations for such a modification. The inspectors considered that the differences between the opening times of the flow control valves on the two loops of the SW demonstrated a weakness in the licensee's design controls for SW.

The licensee's evaluation of the SW system leaks, the quantifying and evaluation of water hammer loads on the SW system, the control of SW flow control valve opening times, and subsequent corrective actions associated with these issues will be tracked as a followup item (Inspector Followup Item 397/9533-01).

4.2 Reactor Core Isolation Cooling (RCIC) Check Valve RCIC-V-28

The licensee replaced the 150 psi pressure rated carbon steel plug check valve with a 600 psi pressure rated stainless steel swing check valve, a more suitable valve for the application. The inspectors verified that the licensee had considered the heavier weight of the replacement valve in their stress analysis of the system. Since installation of the replacement valve involved a carbon steel to stainless steel weld, the inspectors also verified that the licensee had considered the additional thermal radial stresses imposed by the different expansion rates of carbon steel versus stainless steel. The inspectors concluded that the licensee had adequately demonstrated that the change in loads and stresses imposed by the installation of the replacement check valve remained within the approved acceptance criteria. The inspectors identified a minor discrepancy in the installation of the check valve (Section 6.4).

4.3 Baseplate of RCIC Three-Way Pipe Support Pulled from Wall Due to High Axial Loading

On December 7, 1995, the licensee identified that the baseplate of three-way Support RCIC-41 on the 4-inch diameter RCIC steam supply piping had partially pulled away from the wall to which it was attached. The licensee initially considered the RCIC system to be inoperable. The baseplate was separated approximately 1/8 to 1/4 inch from the wall. There appeared to be no damage to the concrete of the wall other than minor spalling. The separation of the baseplate from the wall appeared to have been caused by excessive loading along the axis of the pipe. The licensee noted that the wall had been painted approximately 20 months earlier and that most of the damage appeared to have occurred after the painting. Evidence appeared to suggest that the loading which caused the damage was induced by a steam induced water hammer event.

Investigation by the licensee involved performance of nondestructive examinations at the location of the damaged support and adjacent piping points susceptible to high loads. No damage was found other than the damage to Support RCIC-41. Examination of a nearby downstream 1/4 snubber also detected no damage. This was significant because the snubber, which was expected to have been subjected to similar loads to those experienced by Support RCIC-41, had a low design load capability of approximately 350 pounds. This and other evidence suggested that the load was of low magnitude and had likely originated in the vicinity of Support RCIC-41.

This line (which carries steam) was supposed to be sloped to prevent any condensation from accumulating. Subsequent evaluation by the licensee found that a portion of horizontal pipe near the damaged support appeared to be level and not sloped as required. This was noted while the pipe was in its cold condition. An existing anchor on the adjacent riser was located approximately 40 feet above the elbow connecting the horizontal pipe. When at operating temperature, the pipe would expand downward, causing a slope in the wrong direction on the horizontal line and creating a pocket at the elbow in which to accumulate condensed steam. The licensee postulated that the accumulated water would be expected to impact the piping upon system startup and create the additional loads likely responsible for the damaged support.

The licensee repaired the damaged restraint by relocating anchor bolts of similar diameter and type, but of longer length. The load profile at the new anchor bolt locations was approximately the same as that which existed before the repair, but the repaired restraint was considered to be of a stronger design due to the use of the longer anchor bolts.

The licensee was considering options to either provide a means of removing the accumulated condensate in the line or to reslope the line during the next refueling outage (R11), scheduled to begin in April 1996.

The inspectors were concerned about the operability of the line during the period of time until the next refueling outage. The inspectors noted, however, that evidence indicated that the loads were not high and that the damage to the three-way support likely occurred over several years. Furthermore, the load capacity of Support RCIC-41 had likely increased by the addition of the longer anchor bolts and the calculated system stresses were low.

In order to obtain additional assurance that system operability would not be challenged by excessive loads during system startup, the inspectors and several of the licensee's engineers observed critical points on the piping system during a start of the RCIC system. The start was uneventful. The inspectors considered that there would be reasonable assurance of RCIC operability until additional corrective actions could be implemented during the April 1996 refueling outage. The inspectors concluded that the licensee's investigations into the cause of damage to Support RCIC-41, operability evaluations, and completed and planned corrective actions were thorough and comprehensive with an appropriate emphasis on safe system operation.

4.4 Interdisciplinary System Walkdowns

To improve support of plant operations, the licensee stated their intention to conduct interdisciplinary system walkdowns and periodic reviews for targeted systems under the system management concept. Additionally, the licensee's Performance Enhancement Strategy indicates that quarterly interdisciplinary system walkdowns would be performed. An inspector evaluated the status of these walkdowns and their impact in improving plant operations.

The inspector found that the licensee had targeted 57 systems for interdisciplinary walkdowns. To date (7 months after the R10 outage) 15 of the targeted 57 systems had been walked down by interdisciplinary teams and the last walkdown had been performed in August 1995. The inspector reviewed some of the findings from the 15 completed walkdowns. In these walkdowns the licensee identified errors in, or potential improvements to drawings, the Final Safety Analysis Report, system operating and surveillance procedures, and the systems' material condition.

The inspector discussed the limited progress that the licensee had made in performing the interdisciplinary walkdowns for the 57 targeted systems. The licensee indicated that the walkdowns were useful, but involved more resources than they initially envisioned. The licensee also noted that system engineers had been conducting weekly walkdowns of the 57 targeted systems. The purpose of the weekly walkdowns is to assess the systems' material condition and to trend systems' performance. The inspector noted that the system engineers did not use drawings nor was it management's expectation for the system engineers to use drawings when performing the weekly walkdowns. The licensee indicated the weekly walkdowns, in conjunction with rotating maintenance work week, have resulted in improved plant material condition.

The inspector concluded that in general, based on the system walkdowns, the material condition of the ESF systems had improved and that the limited number of interdisciplinary walkdowns that had been completed were useful in that the walkdowns identified discrepancies and recommended improvements. The inspector also concluded that the licensee had been slow in performing the interdisciplinary walkdowns of the targeted 57 systems. The inspector concluded that management oversight of the interdisciplinary walkdowns process required strengthening.

5 SURVEILLANCE TESTING (61726)

The inspectors reviewed TS surveillance tests on a sampling basis to verify that:

- a technically adequate procedure existed for performance of the surveillance tests;
- the surveillance tests had been performed at the frequency specified in the TS and in accordance with the TS surveillance requirements; and
- test results satisfied acceptance criteria or were properly dispositioned.

5.1 Plant Procedure Manual (PPM) 7.4.3.1.1.16, "RPS Scram Discharge Volume Level Channels A & C 1/2 SCRAM and Control Rod Block on Channels G & H - CFT/CC"

The inspectors observed the portion of this test pertaining to the calibration check for control rod drive (CRD) scram discharge volume Level

Switch CRD-LS-13A. Level Switch CRD-LS-13A is a part of the reactor protection system instrumentation and is required by TS to be performed quarterly. This test had the potential to scram the reactor if not properly performed.

With one exception, the test was performed in accordance with the procedure. One of the procedural steps required signoff by operations that a valve was closed and sealed. The test personnel verified that the valve was closed. Operations had not yet arrived to sign off the step, but the test personnel proceeded with two more steps in the procedure until questioned by the inspectors. The inspectors considered that the crew had not followed the procedure, but that there was minor safety significance, since the valve was fully closed. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

Other observations during the licensee's performance of PPM 7.4.3.1.1.16 included good skill and knowledge on the part of personnel performing the surveillance; steps were performed in a deliberate manner with second verification being clearly present, and self-critical and conscientiousness in proposing better ways to perform the work next time. For example, part of the surveillance required manipulation of a valve carrying demineralized water. The valve was adjacent to a high radiation source (approximately 600 mrems/hour). The crew proposed a way to reroute the demineralized water line and valve. It appeared that the proposed modification would be minor. The valve would then be in an area of about 30 mrems/hour, a significant reduction in personnel exposure. The inspectors considered that the Instrument and Control (I&C) technicians performing the surveillance test appeared well qualified and had demonstrated an attitude of plant ownership.

The inspectors witnessed portions of the following surveillance tests and identified no significant strengths or weaknesses:

Procedure	Description
7.4.8.1.1.2.11	DG Monthly Operability Test
15.1.4	Diesel Fire Pump Monthly Operability Test
7.4.3.8.2.1	Turbine Governor Valve Test
7.4.7.1.1.1	Standby Service Water Loop A Valve Position
7.4.7.3.3B	RCIC Quarterly Operability Test

6 MAINTENANCE OBSERVATIONS (62703)

During this 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/quality control involvement, proper use of clearance tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting.

6.1 Rep'a^ement of Handwheels on Scram Discharge Volume (SDV) System Valves

In conjunction with the performance of PPM 7.4.3.1.1.16, the I&C crew was also changing out some valve handwheels for color-coded handwheels. The purpose of color coding the handwheels was to aid in prompt identification of certain SDV valves during performance of periodic surveillance testing of the SDV system. The inspectors considered this to be a positive action by the licensee to assist workers in promptly identifying plant equipment and thereby reduce radiation exposure to crews in the future.

During performance of the handwheel changeouts, the inspectors observed that the crew did not initially have the correct socket for removing the handwheels. The crew identified that mechanical maintenance could have been contacted beforehand to identify the correct socket, thus eliminating any extra time spent in a significant radiation area (approximately 30 mrem/hour and greater in some areas). The inspectors agreed that this activity could have been better planned to reduce radiation exposure to the I&C technicians performing the handwheel changeouts. The inspectors also noted that the technicians were only able to install two of the nine handwheels scheduled for replacement because the dose allowed for the job would have been exceeded had any more work been performed. The inspectors noted that the licensee decided to identify the remaining handwheels with large tags.

6.2 Reactor Feedwater Pump A Lube Oil Temperature Controller, TSW-TIC-14a

On January 4, 1996, the inspectors observed maintenance on the turbine service water (TSW) lube oil temperature control valve Controller, TSW-TIC-14a, for reactor feed Pump A. This job required coordination with operations to stabilize lube oil temperatures with the plant operating at 100 percent power. The inspectors observed two instrument technicians remove the controller from Instrument Rack E-IR-16 for calibration work in the instrument shop. The work was supervised by the associated systems engineer. The inspectors observed good maintenance practices. The work was prebriefed with the duty operations shift support supervisor and well planned. The work was coordinated by the licensee's work control group work-week leader. The work appeared in compliance with the licensee's administrative and maintenance procedures. The required QA/quality control processes were used. The pneumatic controller was cleaned, recalibrated and reinstalled. The system was returned to service on January 5, 1996.

6.3 Install New Filter Head Assembly for the Digital Electrohydraulic Control System, DEH-P-1B, Discharge Full Flow Filter

On January 5, 1996, the inspectors observed the installation of a new prefabricated filter head assembly for the digital electrohydraulic control system (DEH-P-1B) discharge full flow filter. The inspectors observed good maintenance practices. The work was prebriefed with the duty operations shift support supervisor and well planned. The work was coordinated by the licensee's work control group work-week leader. The work appeared in compliance with the licensee's administrative and maintenance procedures. The required QA/quality control processes were used.

6.4 Valve RCIC-V-28 Replacement

Inspectors observed Valve RCIC-V-28 following its installation. The inspectors noted that the installation appeared acceptable with the exception that the flange faces of the connecting piping appeared not to be perpendicular. The inspectors requested that the licensee verify correct alignment of the flanges. As corrective actions the licensee verified that the flange did not leak during postmaintenance testing and plans to further investigate the cause of the misalignment during the upcoming refueling outage.

The inspectors considered the licensee's response to this problem timely and the corrective actions adequate.

7 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.

7.1 Fire Protection

The inspectors observed firefighting equipment and controls for conformance with administrative procedures. The inspectors noted that a high number of fire impairments existed for which fire tours were being conducted because of concerns with Thermo-Lag and fire seals.

7.2 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.

7.2.1 Licensed Operator Access to Radiologically Controlled Areas (RCA) Without Proper Dosimetry

In an incident on December 28, 1995, a licensed operator left his direct reading dosimetry in the control room where he had been reviewing a piping diagram. The error was detected when this individual attempted to egress the RCA. The duty shift manager generated a PER on this incident; the individual was remediated on management expectations, and was directed to send an e-mail to all of his peers regarding this issue. The inspectors determined that

these actions were appropriate since the individual had made a direct exit from the control room to the RCA egress point and his current exposure could be accurately determined. To address personnel entering the RCA without the required dosimetry, the licensee is in the process of installing turnstiles at the entrances to the RCA. The inspectors viewed this as a positive effort by the licensee to prevent employees from entering the RCA without dosimetry, a problem in the past.

7.2.2 Measures to Limit Contamination of Air and Water Hoses

During observation of a surveillance test, the inspectors noted that the licensee had installed air and water connections at the boundary to the surface contaminated area (SCA) in order that future work in the SCA which might require air or water could access the air and water outside the SCA without needlessly contaminating hoses. The inspectors viewed this as a positive effort by the licensee to limit contamination of air and water hoses.

7.3 Plant Housekeeping

The inspectors observed plant conditions and material and equipment storage to determine the general state of cleanliness and housekeeping. Housekeeping in the RCA was evaluated with respect to controlling the spread of surface and airborne contamination. Generally, housekeeping was observed to be good with the exception the solid radiological waste and hot metallurgical laboratory areas. The material condition of the reactor closed cooling (RCC) system pumps, heat exchangers, and associated piping appeared somewhat degraded over what the inspectors had observed a year ago. However, the operability of the RCC system appears not to have been affected. While the visible vent screens on the HPCS pump were clean and free of dust and debris, the vent screens on the underside of the pump were almost closed with dust, indicating that periodic cleaning of these components may focus more on the visible portions of the components.

7.4 Security

The inspectors periodically observed security practices to ascertain that the licensee's implementation of the security plan was in accordance with site procedures, the search equipment at the access control points was operational, the vital area portals were kept locked and alarmed, personnel allowed access to the protected area were badged and monitored, and the monitoring equipment was functional. No problems were noted during these observations.

7.5 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.

7.6 Plant Chemistry

The inspectors reviewed chemical analyses and trend results for conformance with TS and administrative control procedures. Plant chemistry was good during this inspection period. The inspectors noted that the chemistry index for reactor coolant for the last two inspection periods has been 1.0, indicating excellent reactor water chemistry.

7.7 Special Nuclear Material Issue

On December 29, 1995, the licensee informed the inspectors that an internal audit on December 28, 1995, revealed that less than 2 mg of special nuclear material (SNM) were unaccounted for in the licensee's records. Possession of the SNM was provided in the WNP-2 license, Section 2.B(3). The material (uranium oxide) was part of a new intermediate range monitor (IRM) that had been stored in the radwaste building. The IRM had been damaged and had never been used. The IRM was apparently moved after the June 1995 outage along with other excess outage equipment to a double-locked cargo van that was found in a locked warehouse area near the site. This area is outside the licensee's protected area, but still within the owner-controlled area. Therefore, the licensee was reasonably assured that they had not lost control of the SNM during the 5 months that it was unaccounted for. Because the material was less than 2 mg, the issue was not required to be reported to the NRC. However, because of the sensitivity of SNM, the licensee informed the resident staff and wrote a PER on the issue and evaluated if their accountability procedures were adequate. On January 4, 1996, the licensee informed the inspectors that their assessment concluded that two actions to improve SNM accountability would be implemented:

- Improvement of SNM accountability procedures.
- Development of a program to insure that all SNM on site is properly labeled with instructions not to move without proper authorization.

The inspectors determined that these actions were adequate.

7.8 Conclusions

Plant support performance was generally good during this inspection period. The licensee has or is taking actions to correct identified weaknesses in this functional area.

8 FOLLOWUP - ENGINEERING (92903)

8.1 TS Fuel Operational Limits

Twice in November 1995, while increasing power following maintenance on the control rod drive hydraulic power units, the licensee exceeded the maximum fraction of limiting power density (FDLRC) for Siemens fuel. The licensee

took the required action of TS 3.2.2 and adjusted average power range monitor setpoints each time. The inspectors questioned the licensee about these two entries into the TS action statement because the response of the operating crews was different and it appeared that better planning could have avoided entry into the action statement.

The inspectors discussed these two items with the operating crews and the manager of reactor fuels. The licensee appeared to have fully evaluated the conditions that led to the entry into the TS action statement prior to entering the action and determined that the fuel would not be adversely impacted. The licensee acknowledged that the operating crew response to entering this action statement should be consistent and that management expectations would be clarified in procedures to obtain a consistent response. The licensee also indicated that in the future their planning would attempt to minimize the time in the action statement. The inspectors had no safety concerns and the licensee action appeared acceptable.

8.2 <u>(Closed) Unresolved Item 397/9306-06: Suppression Pool Cooling Mode (SPCM) Test was Augmented</u>

This item was opened to evaluate the licensee's use of the wetwell spray line during surveillance testing of the spent fuel cooling mode for the residual heat removal system. The use of the wetwell spray line to achieve the flow required by TS was not described in the FSAR, nor had the emergency operating procedures or system operating procedures recognized its use.

The TS did not specify the pathway for return of flow to the suppression pool. From a safety perspective, the use of both the return line and wetwell spray lines was evaluated to be acceptable since the system safety function is to return cooled suppression pool water to the suppression pool. This is accomplished by either flowpath. The licensee provided an evaluation which showed that a reduced flow of 7000 gpm was sufficient for accomplishing suppression pool cooling.

The licensee has made changes to FSAR Section 6.2.2.1 and system operating Procedure PPM 2.4.2 to reflect the wetwell flowpath. The applicable emergency operating procedure refers to the system operating procedure and therefore, appropriately reflects the use of the wetwell spray line. The inspectors noted that FSAR Section 7.3.1.1.5.b had not been changed. Licensee personnel indicated that this FSAR section would be revised to be consistent with Section 6.2.2.1 and the operating procedures. These actions were acceptable.

The use of the wetwell spray line during surveillance testing, although not reflected in the FSAR or operating procedures, was not considered to be safety significant.

8.3 <u>(Closed) Inspectors Followup Item 397/9429-03: Inservice Testing of Waterleg Pumps</u>

This followup item documented that the licensee had not included the Emergency Core Cooling System and the RCIC waterleg pumps in their inservice testing program. The licensee concluded this was acceptable because the pumps were not required to perform a specific safety function. The pumps ran continuously and were monitored by control room indication and alarms, and alternate methods were available to keep the injection lines filled if the waterleg pumps failed.

The Office of Nuclear Reactor Regulation reviewed the licensee's justification for not including these waterleg pumps in the inservice testing program and concluded that the licensee's rationale was acceptable.

ATTACHMENT 1

1 PERSONS CONTACTED

Washington Public Power Supply System

J. Albers, Radiation Protection Manager
*D. Atkinson, Reactor and Fuels Engineering Manager
*J. Baker, Training Director
*R. Barbee, System Engineering Manager
*W. Barley, Quality Assurance Director
P. Bemis, Regulatory and Industry Affairs Director
*D. Coleman, Regulatory Services Manager
L. Fernandez, Licensing Engineer
*N. Hancock, Shift Manager
V. Harris, Maintenance Specialist
*P. Ingersoll, NSSS Supervisor
*A. Langdon, Assistant Operations Manager
T. Love, Chemistry Manager
*J. McDonald, Assistant Engineering Director
M. Monopoli, Maintenance Manager
J. Muth, Quality Support Manager
W. Oxenford, Outage/Work Control Supervisor
V. Parrish, Vice President Nuclear Operations
*J. Pedro, Compliance Specialist
*B. Pesek, Project Management Supervisor
*W. Pfitzer, Compliance Specialist
W. Rigby, Health Physics Supervisor
G. Sanford, Planning, Scheduling, Outage Manager
*C. Schwarz, Operations Manager
L. Sharp, Assistant Engineering Director
*G. Smith, Plant General Manager
*J. Swailes, Engineering Director
D. Swank, Licensing Manager
P. Taylor, Shift Manager
*J. Weber, System Engineer
*R. Webring, Support Services Director

U.S. Nuclear Regulatory Commission

*R. Barr, Senior Resident Inspector
*G. Replogle, Resident Inspector
*G. Johnston, Senior Project Inspector
H. Wong, Chief, Reactor Projects Branch E (by phone)

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

*Attended the exit meeting on January 18, 1996.

2 EXIT MEETING

An exit meeting was conducted on January 18, 1996. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspectors' findings. The licensee did not identify that any proprietary information was provided to, or reviewed by, the inspectors.

ATTACHMENT 2

ACRONYMS

CRD	control rod drive
CRS	control room supervisor
DG	diesel generator
ESF	engineered safety features
FSAR	Final Safety Analysis Report
HPCS	high pressure core spray
I&C	instrument and control
IRM	intermediate range monitor
LCO	limiting condition for operation
MCC	motor control center
NRC	U.S. Nuclear Regulatory Commission
PER	problem evaluation request
PPM	plant procedure manual
QA	quality assurance
RCA	radiologically controlled area
RCC	reactor closed cooling
RCIC	reactor core isolation cooling
RO	reactor operator
SCA	surface contaminated area
SDV	scram discharge volume
SM	shift manager
SNM	special nuclear material
SW	service water
TS	Technical Specifications
TSW	turbine service water
WNP-2	Washington Nuclear Project-2