U.S. NUCLEAR REGULATORY COMMISSION

REGION V

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| Report No: | 50-397/92-28 |
| Docket No: | 50-397 |
| License No: | NPF-21 |
| Licensee: | Washington Public Power Supply System<br>P. O. Box 968<br>Richland, WA 99352 |
| Facility Name: | Washington Nuclear Project No. 2 (WNP-2) |
| Inspection at: | WNP-2 site near Richland, Washington |
| Inspection Conducted: | July 13 - August 23, 1992 |
| Inspectors: | R. C. Sorensen, Senior Resident Inspector<br>D. L. Proulx, Resident Inspector |

Approved by: P H Johnson 9/16/92
P. H. Johnson, Chief, Reactor Projects Section 1 — Date Signed


Summary:

Inspection on: July 13 - August 23, 1992 (50-397/92-28)

Areas Inspected: Routine inspection by the resident inspectors of control room operations, licensee action on previous inspection findings, operational safety verification, surveillance program, maintenance program, licensee event reports, special inspection topics, and procedural adherence. During this inspection, Inspection Procedures 61702, 61705, 61706, 61726, 62703, 71707, 71711, 90712, 92700, 92701, 92702 and 93702 were used.

Safety Issues Management System (SIMS) Items: None.

Results:

General Conclusions and Specific Findings

Significant Safety Matters: None.

Summary of Violations and Deviations: One violation was identified involving failure to maintain proper posting for a radiation area.

Open Items Summary:

One followup item and seven LERs were closed; one new item was opened.

## DETAILS

1. Persons Contacted

   V. Parrish, Assistant Managing Director for Operations
   *J. Baker, Plant Manager
   L. Harrold, Assistant Plant Manager
   *D. Pisarcik, Radiation Protection Manager
   *J. Harmon, Maintenance Manager
   *H. McGilton, Operational Assurance Manager
   *G. Sorensen, Regulatory Programs Manager
   *J. Wyrick, Outage Manager
   *J. Peters, Administrative Manager
   W. Shaeffer, Acting Operations Manager
   *R. Webring, Plant Technical Manager
   *M. Mann, Acting Assistant Operations Manager
   *C. Fies, Compliance Engineer
   *D. Schumann, Operational Events Assessment Engineer

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

   *Attended the Exit Meeting on August 26, 1992.

2. Plant Status

   At the start of the inspection period, the plant was in Mode 4 (cold shutdown) to perform an investigation on the two failures of safety relief valve MS-RV-3B and install a replacement. In addition, the startup was on hold to address issues related to the inability of fire seals between the ECCS pump rooms to withstand flooding. The reactor was restarted on July 18, and then was manually scrammed from 7% power to support testing of the scram discharge volume vent and drain valves. Following recovery from this planned scram, the licensee commenced reactor startup on July 19. Later that day, MS-RV-3B was successfully retested and the licensee commenced power ascension. On July 21, the licensee held at 11% power to support torsional testing of the new low pressure turbine rotors. After successful testing, the licensee continued with power ascension, until achieving 100% power on July 27.

   On July 31, the licensee began a scheduled downpower to repair steam leaks and the dump valve for #1 feedwater heater. However, just after commencing this downpower maneuver, operators noted that the "B" phase-to-phase fault protection had failed on the "B" main transformer. Reactor power was reduced to 15%, and the main generator was removed from the grid on August 1. The "B" phase was switched to the spare transformer, and the generator was reconnected to the grid. The reactor achieved 100% power again on August 4.

   On August 4, NRC Chairman Ivan Selin, accompanied by Regional Administrator John Martin and the Senior Resident Inspector, toured the site, and met with licensee management.

The reactor remained at full power until August 13, when an increase in unidentified leakage to 5 gpm required the licensee to declare an Unusual Event and commence a reduction in reactor power to 5% to attempt to identify the leakage. On August 14, with the plant at 5% power the licensee entered the drywell and located the leak. The leak was from the packing of valve RWCU-V-103, which was subsequently backseated to stop the leak. Later on August 14, the licensee commenced power ascension with the intent of achieving 100% power. However, on August 15, with the reactor at 36% power, the reactor experienced power oscillations. Power oscillated from 23 to 47% power peak-to-peak every two seconds. Operators manually scrammed the reactor and declared an Unusual Event. The reactor was subsequently cooled down to Mode 4 (cold shutdown). An NRC Augmented Inspection Team (AIT) was dispatched to the site to investigate this event. The reactor was in Mode 4 at the end of the inspection period.

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

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

a. (Closed) Violation (397/91-44-06): Failure to Report Containment Atmosphere Control (CAC) Flow Controller Deficiency in a Timely Manner

The licensee had identified a deficiency with the CAC flow controllers that rendered the CAC system inoperable. The discovery was made on August 7, 1991 but the 50.72 notificatio was not made until October 31. The LER was not issued until December 2.

In their response, the licensee indicated that the reason for the excessive length of time was an inadequate management process that allowed reportability decisions to extend beyond reasonable timeframes. The licensee implemented the following corrective actions:

- Action was taken to reduce the backlog of items requiring a reportability evaluation to less than ten. As of August 13, 1992, the backlog of reportability evaluations stood at five.
- The responsibility for root cause analyses for NRC violations was transferred from the Compliance organization to the Operating Experience Assessment group. This allowed more time for Compliance to perform reportability evaluations.
- An independent assessment was conducted by an outside contractor of the reportability evaluation process and a number of improvement actions were recommended.

The inspector concluded that the licensee's corrective actions were appropriate. This item is closed.

4. Root Cause Assessment of Stuck Safety Relief Valve (93702)

During the previous inspection period (Inspection Report 50-397/92-23, paragraph 4), MS-RV-3B initially failed to open from the control room during testing at 15% power on July 6, 1992, and then failed to reseat when operated from the remote shutdown panel. The licensee's initial investigation appeared inadequate, attributing these failures to an intermittently sticky solenoid on the valve operator. The solenoid was replaced. When the valve was retested during the subsequent startup on July 11, however, it opened but again failed to reseat, prompting another reactor scram.

The subsequent investigation, which appeared very thorough, was coordinated by a team of licensee personnel led by the Engineering Director. This investigation included the use of offsite vendor testing facilities. The licensee determined the root cause of the event to be an oversized blowdown ring which was installed in the valve during the 1992 refueling outage. This blowdown ring was taken from onsite spares, but had inadvertently not been identified by the vendor (prior to initial plant startup) as a part to be recalled when a design change was issued for the safety relief valves. The team appeared to insightfully develop a thorough fault tree that methodically tested each potential cause for the event, and appeared to perform in a formal, deliberate manner. MS-RV-3B was repaired and successfully retested on July 19. LER 92-33 was issued to further document the licensee's findings and corrective actions.

No violations or deviations were identified.

5. Unusual Event (UE) due to High Unidentified Leakage (93702)

On August 12, during day shift, operators noted that drywell unidentified leakage had increased from 0 gpm to approximately 0.8 gpm during the shift. Operators also reported that the containment LOCA radiation monitors increased from 100 to approximately 70,000 counts per minute for particulates. The licensee closely monitored these parameters over the next 24 hours, and reported that drywell unidentified leakage had very slowly increased to 1.6 gpm, and the containment LOCA radiation monitor indicated approximately 130,000 counts per minute of particulates at the end of day shift on August 13. At 6:55 p.m. on swing shift, drywell leakage started increasing rapidly and exceeded a 2 gpm increase in unidentified leakage over a four-hour period. A reactor shutdown was commenced at that time as required by the Technical Specifications. At 7:36 p.m., drywell unidentified leakage reached its peak level of 5.02 gpm, prompting the shift manager to declare an Unusual Event at 7:40 p.m. as prescribed by the licensee's Emergency Plan. As power was decreased, unidentified leakage decreased to about 2.8 gpm due to lower reactor pressure. The NRC was notified of the UE at 8:36 p.m.

The licensee decreased reactor power to 5% and deinerted the drywell to make an entry to locate the leak. The licensee entered the drywell at 7:46 a.m. on August 14, and the Shift Support Supervisor (SSS) found the leakage to be a valve packing leak on RWCU-V-103. The UE was exited at 8:58 a.m. based on identification of the leak. The SSS promptly backseated RWCU-V-103, and drywell leakage immediately decreased to 0.6 gpm.

The inspector entered the drywell with licensee personnel to tour the drywell and to attempt to identify the source of the final 0.6 gpm leakage. The licensee determined the leakage to be condensation from the drywell coolers and four minor packing leaks. The licensee also ensured that RWCU-V-103 was not leaking. The inspector concurred with the licensee's conclusions. At 5:10 p.m. the licensee commenced power ascension and was synchronized to the grid at 9:09 p.m. The licensee reported this event pursuant to 10 CFR 50.72, but determined that the event was not reportable in accordance with 10 CFR 50.73, because the shutdown was not completed.

No violations or deviations were identified.

6. Operational Safety Verification (71707)

a. Plant Tours

The following plant areas were toured by the inspectors during the course of the inspection:

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

b. The following items were observed during the tours:

(1) Operating Logs and Records. Records were reviewed against Technical Specification and administrative control procedure requirements.

(2) Monitoring Instrumentation. Process instruments were observed for correlation between channels and for conformance with Technical Specification requirements.

(3) Shift Manning. Control room and shift manning were observed for conformance with 10 CFR 50.54.(k), Technical Specifications, and administrative procedures. The attentiveness of the operators was observed in the execution of their duties, to ascertain if the control room was free of distractions. No radios or non-work related reading materials were noted in the control room.

On August 8, however, the inspector noted that the entire complement of on-shift operators were participating in General Employee Training (GET) in the control room. This training included taking examinations while on shift. In discussion with the Assistant Plant Manager, the inspector questioned whether it appeared appropriate to conduct GET during the crew's shift. The licensee subsequently installed a video cassette recorder (VCR) and a monitor in one of the back rooms of the control room with the intent of one operator at a time watching the video while on shift. However, the on-shift crew (without the knowledge of plant management) moved the VCR and monitor to the control room operating area so that the entire crew (except one crew member attending to the panels) could watch the video at the same time. The inspector met with the Assistant Plant Manager, the Operations Manager, and the Deputy Managing Director on August 9 concerning these actions of the operating crew, and they agreed with the inspector that this type of distraction was inappropriate for operating crews on shift while the plant was at power. The monitor and the VCR were immediately removed from the control room.

(4) Equipment Lineups. Valves and electrical breakers were verified to be in the position or condition required by Technical Specifications and administrative procedures for the applicable plant mode. This verification included routine control board indication reviews and conduct of partial system lineups. Technical Specification limiting conditions for operation were verified by direct observation.

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

(6) General Plant Equipment Conditions. Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that would prevent the system from fulfilling its functional requirements. Annunciators were observed to ascertain their status and operability.

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

(8) Plant Chemistry. Chemical analyses and trend results were reviewed for conformance with Technical Specifications and administrative control procedures.

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

During a tour of the reactor building (RB) on July 31, 1992, the inspector noted that the northwest valve room on the 471-foot level of the RB was not posted as a radiation area as it had been previously. The radiation area sign was resting on a single padeye, obscured from sight. The inspector notified the Technical Manager, who was also touring the plant, who subsequently informed HP. The Technical Manager guarded the area as a compensatory measure until the HP technician arrived. The HP technician surveyed the area to confirm that a radiation area still existed and subsequently reposted the area. Radiation measurements indicated various radiation levels up to 10 millirem per hour in the area. The licensee wrote a PER and convened an incident review board (IRB) to determine the cause of this event. The IRB found that mechanics had removed the posting to support installation of a metal gate to the entrance of the northwest valve room, but failed to involve HP for compensatory measures. The failure to maintain proper posting for a radiation area is an apparent violation of 10 CFR 20.203 and TS 6.8.1.k (Violation 397/92-28-01).

(10) Plant Housekeeping. Plant conditions and material/equipment storage were observed 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. The licensee initiated an aggressive plant cleanup and painting evolution that significantly improved the overall material condition of the plant during the inspection period.

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

c. Engineered Safety Features Walkdown

Selected engineered safety features (and systems important to safety) were walked down by the inspectors to confirm that the systems were aligned in accordance with plant procedures. During 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.

Accessible portions of the following systems were walked down on the indicated dates.

| System | Dates |
|---|---|
| Diesel Generator Systems, Divisions 1, 2, and 3. | July 31, August 11 |

| | |
|---|---|
| Hydrogen Recombiners | July 31 |
| Low Pressure Coolant Injection (LPCI) Trains "A", "B", and "C" | August 11 |
| Low Pressure Core Spray (LPCS) | August 11 |
| High Pressure Core Spray (HPCS) | August 11 |
| Reactor Core Isolation Cooling (RCIC) | August 11 |
| Residual Heat Removal (RHR), Trains "A" and "B" | August 11 |
| Scram Discharge Volume System | July 31 |
| Standby Liquid Control (SLC) System | July 31 |
| 125V DC Electrical Distribution, Divisions 1 and 2 | July 31 |
| 250V DC Electrical Distribution | July 31 |

One violation was identified, as discussed above.

7. Plant Startup from Refueling (71711)

The inspector observed portions of the licensee's startup from the R7 refueling outage, from criticality to 100% power. Plant Procedures Manual (PPM) procedure 3.1.2, "Reactor Plant Cold Startup," was used by the inspector as guidance. Operators appeared to perform their duties in a formal and deliberate manner, and power ascension to full power was completed with no problems.

No violation or deviations were identified.

8. Core Power Distribution (61702)

The inspector reviewed the licensee's process for determining power distribution limits. The inspector used licensee procedure 7.4.2.1, "Power Distribution Limits," as guidance. The licensee used a computer code called "POWERPLEX" to perform the calculations necessary to determine the linear heat generation rate (LHGR), average planar linear heat generation rates (APLHGR), and minimum critical power ratios (MCPR). POWERPLEX performs these calculations and compares them to the Technical Specification thermal limits based on reactor power, total core flow, core life, and type of fuel assembly. In addition, the program ensures that the Lead Test Assemblies (LTAs) do not lead the core in bundle or nodal power. The inspector concluded that the licensee's process for determining these parameters appeared to be proper, and that the values obtained from July 25 to July 27, during initial power ascension, were within TS limits.

No violations or deviations were identified.

9. Incore/Excore Detector Calibration (61705)

The inspector reviewed the licensee's program for calibrating the local power range monitors (LPRMs) by reviewing licensee procedures, interviewing personnel, and witnessing portions of the licensee's calibration activities. The inspector reviewed licensee procedure PPM 9.3.3, "LPRM Calibration," to ascertain whether it was in accordance with the TS and the FSAR.

During review of PPM 9.3.3, the inspector noted that the procedure was written solely for use of all five traversing incore probe (TIP) machines for full core calibration of the LPRM detectors, including inserting all 5 TIP machines through a common LPRM string to calibrate the TIPs for operability per TS 4.3.7.7. However, TS 3.3.7.7.b. states that "with four traversing in-core probe machines, an inaccessible LPRM string may be calibrated using a traversing in-core probe scan from a symmetric string provided that an 'A' type control rod pattern is in use and the total core TIP asymmetry is less than 6% (standard deviation)." PPM 9.3.3 did not provide for the use of four TIP machines for calibration of the LPRMs, nor was there any other implementing procedure for employing this option in the TS. On July 25, the inspector apprised the Supervisor of Reactor Systems of this observation, who stated that the licensee would generate a change to PPM 9.3.3 to implement TS 3.3.7.7.b if it became necessary.

On July 29, while the licensee was obtaining data using the TIPs for LPRM calibration, the "B" TIP indexer became stuck at position B-3. Operators were unable to complete calibration of the LPRMs, because the licensee had no implementing procedure to allow LPRM calibration with four TIP machines. Plant Technical personnel subsequently cycled the "B" TIP indexer switch several times to free the B indexer from the B-3 position, and completed data acquisition for the full core LPRM calibration. The LPRMs were subsequently adjusted per the TS.

The "B" TIP indexer was declared inoperable on July 30. The licensee then issued deviations to PPM 9.3.3, and other appropriate procedures to implement the allowance of four TIP machines for full core LPRM calibration for the subsequent occasion (1000 effective full power hours of plant operation) of LPRM calibration. On August 14, when the licensee reduced power to 5% and entered the drywell to backseat RWCU-V-103, the licensee replaced the B TIP indexer, and declared it operable.

No violations or deviations were identified.

10. Core Thermal Power Evaluation (61706)

The inspector evaluated the licensee's process for determining that the core thermal power (CTP) was less than or equal to the licensed full power level of 3323 thermal megawatts. The inspector's evaluation consisted of review of procedures, observation of licensee personnel, and hand calculation of core thermal power using the licensee's procedure.

The licensee's process for computing core thermal power employs three methods: (1) the plant process computer continuously calculates CTP based on inputs from plant instrumentation; this program also computes 1-minute, 15-minute, 2-hour, 4-hour, and 8-hour averages on a continuous basis to ensure compliance with the licensed power level; (2) operators obtain data from the appropriate control room instrumentation and input this data into a personal computer program; and (3) operators obtain data from control room instrumentation and manually hand calculate CTP per PPM 9.3.1, "Manual Core Heat Balance." The licensee considers the process computer the primary method of calculating CTP.

The inspector determined that the primary method of calculating CTP used the appropriate inputs from calibrated instrumentation and appeared to properly compute CTP. The inspector manually calculated CTP using PPM 9.3.1 and obtained results within one percent of the values the process computer displayed. However, the inspector noted errors in the PPM 9.3.1 and PC program methods for determining CTP.

The inspector noted that both the PC program and PPM 9.3.1 required inputs that appeared to be from the wrong instrumentation for reactor water cleanup (RWCU) inlet and outlet temperatures. If an operator calculated CTP using the PC program and/or PPM 9.3.1 as written, the results would apparently be 10 megawatts thermal less than actual CTP. These apparent errors could have been significant if the licensee was operating at what would appear to be 100% power and was using one of these methods for computing CTP for an extended period of time (e.g., exceeding the licensed full power level for greater than eight hours). In addition, the inspector found three other minor apparent errors in PPM 9.3.1, in that the wrong line numbers were referenced for transferring data from the data table to the equations where the hand calculations were made. While these errors represented potential problems if use of the backup calculation methods had been necessary, the licensee considered the process computer to be the primary method of calculating CTP. As previously noted, this was determined to properly calculate CTP. The above errors were discussed with the licensee, who corrected these errors before the end of the inspection period.

No violations or deviations were identified.

11. Surveillance Testing (61726)

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

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

| Procedure | Description | Dates Performed |
|---|---|---|
| 7.4.4.2.1.2 | Safety Relief Valve Acoustic Monitor Channel Functional | July 19 |

Test and Auto-Depressurization
System (ADS) Operability

No violations or deviations were identified.

12. Plant Maintenance (62703)

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

The inspector witnessed portions of the following maintenance activities:

| Description | Dates Performed |
|---|---|
| AR-9805, Troubleshoot and Repair Valve Position Indication for MS-RV-3B | July 14 |

No violations or deviations were identified.

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

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

| LER NUMBER | DESCRIPTION |
|---|---|
| 92-18 | Appendix R Concerns |
| 92-19 | ADS Potentially Inoperable |
| 92-26 | Spring Pack Gap Improperly Set on Drywell Spray Valve |
| 92-27 | Lack of Breaker Coordination Caused By Instantaneous Trip Circuitry |
| 92-29 | Shutdown Cooling Isolation Due to Transfer of RPS "B" to Alternate Power Supply |
| 92-31 | Potential For Diesel Generator Overload Due to Electrical Separation Problems |
| 92-33 | Improper Safety/Relief Valve (SRV) Reseat Pressure and Reactor Scram |

No violations or deviations were identified.

14. Exit Meeting

The inspectors met with licensee management representatives periodically during the report period to discuss inspection status, and an exit meeting was conducted with the indicated personnel (refer to paragraph 1) on August 26, 1992. The scope of the inspection and the inspectors' findings, as noted in this report, were discussed with and acknowledged by the licensee representatives.

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