U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

REGION V

Report No. 50-397/84-22

Licensee: Washington Public Power Supply System
P. O. Box 968
Richland, WA 99352

Facility Name: Washington Nuclear Project No. 2 (WNP-2)

Docket No.: 50-397

License No.: NPF-21

Inspection at: WNP-2 Site near Richland, Washington

Inspectors: D. Heno, Jr. 10/1/84
A. D. Toth, Senior Resident Inspector Date

D. Haar, Jr. 10/1/84
R. S. Waite, Resident Inspector Date

Approved by: D. Haar, Jr. 10/1/84
P. H. Johnson, Chief Date
Reactor Projects Section 3

Summary:

Inspection on August 4-31, 1984 (Report No. 50-397/84-22)

Areas Inspected:

Routine, monthly inspection by the resident inspectors of control room operations, engineered safety feature status, surveillance program, maintenance program, power ascension test program, licensee event reports, special inspection topics, and licensee action on previous inspection findings.

The inspection involved 176 inspector-hours onsite by two resident inspectors, including 43 hours during backshift work activities.

Results:

No violations or deviations were identified.

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DETAILS

1. Persons Contacted

Washington Public Power Supply System

*R. Corcoran, Operations Manager
*K. Cowen, Technical Manager
*R. Graybeal, Health Physics and Chemistry Manager
*J. Landon, Maintenance Manager
*J. Little, Training Coordinator
*J. Martin, Plant Manager
*M. Monopoli, Manager of Quality
*J. Peters, Administrative Manager
*P. Powell, Licensing Manager
*C. Powers, Assistant Plant Manager
*J. Shannon, Assistant Managing Director For Operations
*J. Sorensen, Regulatory Programs Manager
*D. Walker, Plant Quality Assurance Manager

Energy Facility Site Evaluation Council

*W. Fitch, Executive Secretary

The inspectors also interviewed various control room operators, shift supervisors and shift managers, engineering, quality assurance, and management personnel relative to activities in progress and records.

*Denotes those present at the exit interview.

2. General

The Senior resident inspector and/or the resident inspector were onsite August 6-10, 12-17, 20-24, and 27-31. Backshift inspections were conducted August 6, 7, 9, 12, 15, 20, 23, 28, and 29.

Several regional office inspectors visited the site this month for routine inspection activities. Their activities were documented in other separate inspection reports.

3. Plant Status

The plant had completed test condition #2 power ascension tests, to power levels of 50%. Delays had been experienced due to condenser tube leaks and damage to feedwater piping.

4. Operations Verifications

The resident inspectors reviewed the control room operator and shift manager log books on a daily basis for this report period. Reviews were also made of the Jumper/Lifted Lead Log and Non-conformance Report Log to verify that there were no conflicts with Technical Specifications and that the licensee was actively pursuing corrections to conditions listed in either log. Events involving unusual conditions of equipment were discussed with the control room personnel available at the time of the review and evaluated for potential safety significance. The licensee's adherence to LCO's, particularly those dealing with ESF and ESF electrical alignment, was observed. The inspectors routinely took note of activated annunciators on the control panels and ascertained that the control room licensed personnel on duty at the time were familiar with the reason for each annunciator and its significance. The inspectors observed access control, control room manning, operability of nuclear instruments, and availability of onsite and offsite electrical power. The inspectors also made regular tours of accessible areas of the facility to assess equipment conditions, radiological controls, security, safety and adherence to regulatory requirements. The following items were identified during the above inspections:

a. Standby Service Water

During a weekly operability verification of the Standby Service Water System the inspector noted that remote indication for several valves in the flowpath for both the A and B loops were inoperative. Licensee procedure 2.4.5, "Standby Service Water System", which provides detailed instructions for placing the Service Water System in Standby, specifies in steps 10, 11, and 12 to observe position indication and proper control switch orientation in the control room for these valves. These steps cannot be completed as written because a prerequisite for this procedure requires the breakers for these valves to be locked open and tagged thus deenergizing the position indication in the control room. The inspector visually observed that the valves were in the correct position and the breakers locked open and tagged. The valves had been positioned appropriately and the breakers deenergized as part of a plant modification.

b. Wrong Valves Installed in RHR System

The inspector noted during a review of clearance orders and maintenance work requests (MWR's) that globe valves RHR-V-85A, 85B, and 85C were being modified and/or replaced because GE design required stop check valves in these positions. The licensee reported in a Nonconformance Report on November 17, 1983 that the wrong valves were installed in the above positions. These valves were apparently discovered as part of the "As-Built" program during this time period. In resolution of the NCR, engineering justification was made to leave these valves installed until the first refueling outage. This matter was reviewed and accepted by the resident inspector as part of the work completion, master work list review in December. On December 5, 1983 a request was made to GE to accept these valves "As Is". GE's reply on January 6, 1984 specified that this was unacceptable. The licensee then issued two Project Engineering Directives to replace the valves; an associated controlling Plant Modification Record was reviewed and approved by the Plant Operations Committee (POC) on March 14, 1984. Procurement was accomplished, implementing maintenance work requests were prepared, and the work was completed on July 30, 1984. The established plant verification efforts, apparently, properly identified the discrepancies and effected corrective action. The interim acceptance pending GE review appeared to have sound technical basis, although it did not recognize the particular aspects subsequently raised by GE.

c. Radiation Work Permit Procedure Implementation

Two Bechtel field engineers entered and exited a radiation controlled area without adhering to procedures governing such actions. Mitigating circumstances were such that the actions did not appear to be an item of noncompliance with NRC regulations. The area had been surveyed and found to involve surface contamination less than 1000 dpm, except at the surface of some flanges which ranged from 2000 to 10,000 dpm. The controlled area had been established for work which would involve handling of insulation and repair of the flanges. Dress in coveralls, gloves and shoe covers was prescribed on the radiation work permit as conservative precautionary measures.

(1) The field engineers entered the controlled area for inspection of feedwater system piping that had been damaged due to a plant transient. They did not sign the specific radiation work permit (RWP-594) nor enter the applicable information on their dosimetry cards as prescribed by the RWP procedure 11.2.7.2. Apparently they considered that verbal health physicist foreman approval the prior day (for entry to this area for inspection purposes) was also applicable the next day; however, in the interim the area boundaries and conditions had changed.

(2) When the engineers exited from the controlled area, the inspector observed that they performed a personal radiation survey with an instrument that was not functional (expired battery and not connected to an external power source). This had been set in place the prior day and had been missed by the routine daily source checks of such instruments on August 24. The health physics staff took prompt corrective action which included (a) immediate replacement of the instrument, (b) identification of personnel signed into the two applicable RWP logs and radiation survey of them and their work places, and (c) initiation of a daily check-off list of all portable personal radiation monitors established in the plant (to assure that daily source checks are not missed).

The licensee also committed to review the adequacy of health physics procedures with respect to practices of granting exceptions to specific radiation work permits, such as for inspection purposes versus hands-on work, and the verbal versus written aspects. Resultant management actions will be reviewed during future inspections (84-22-01)

No violations or deviations were identified.

5. Engineered Safety Feature Verification

The inspector performed a detailed walkdown of the A.C. and D.C. Power Distribution Systems in Divisions 1, 2, and 3 and performed a review of licensee procedure 7.4.8.3.2, "Division 1, 2, 3 AC & DC Weekly Breaker Alignment Check". The Onsite Power Distribution System lineup and the licensee procedure were verified to be in accordance with Technical Specification 3.8.3.1 and the FSAR.

The inspectors identified that four heaters of the main steam isolation valve leakage collection system (MSIV-LCS) were not connected to the labelled and activated circuit breakers (13B, 13C, 13D, and 13E) of motor control center MC-7B-A. These breakers were not connected to any loads, and were properly identified as spares on the applicable drawing E509-7 (Revision 38, April 9, 1984); the drawing was available in the control room. However, the Main Steam System operating procedure 2.2.6 revision 3 still showed these breakers as supplying the heaters, as did page 56 of the AC Electrical Power Distribution System operating procedure 2.7.1 revision 2 checklist. Page 144 of this lineup checklist accurately showed the heaters as supplied by breakers in power panel PP-7B-C. This inclusion of the proper breakers in procedure 2.7.1 appeared to provide adequate assurance that the breakers will be properly aligned, since this procedure is directly referenced in the reactor Master Startup Checklist procedure 3.1.1. The procedural inconsistencies appeared to have been due to the informal consideration given to plant procedures when design changes were processed prior to system turnover to the Operations Department prior to plant startup in 1983. Currently, a Plant Modification Procedure specifically requires responsible system engineers to assess the need for operating procedure changes for each plant modification. Correction of the procedure inconsistencies, and licensee actions to consider the generic aspects of this matter, will be reviewed during future inspections. (84-22-02)

No violations or deviations were identified.

6. Surveillance Program Implementation

The inspectors ascertained that surveillance of safety-related systems or components was being conducted in accordance with license requirements. In addition to observation of, and sometimes witnessing and verifying daily control panel instrument checks, the inspectors observed portions of several surveillance tests by operators and instrument and control technicians. Typical activities included the following:

a. Recirculation Flow Unit C

The inspector observed portions of the licensee's performance of approved surveillance procedure 7.4.3.6.24, "Control Rod Block Recirc. Flow Upscale, Inop and Comparator Channel C - CC". This procedure provides instructions for calibration of the Recirculation Flow Units which provide a flow reference signal to the Average Power Range Monitors and the Rod Block Monitors. This procedure performance received special attention by the inspector because prior performance of procedure 7.4.3.6.11 (identical surveillance procedure for Channel A) on August 16 had contributed to a Reactor Trip due to procedural deficiencies. A Procedure Deviation had been made prior to performance of this surveillance and the procedure was completed without incident. The inspector verified that required test instrumentation was calibrated, testing was coordinated with the control room operators, and testing was conducted in accordance with the approved test procedure, and independently verified that the system was returned to service.

b. ADS Trip System B

The inspector observed licensee performance of approved surveillance procedure 7.4.3.3.1.46, "ADS Trip System B Reactor Water Level Low - Level 3 - CFT". The inspector verified that required administrative approvals were obtained prior to commencement of the test, required test instrumentation was calibrated, testing was coordinated with the control room operators, and testing was conducted in accordance with the approved test procedure; and independently verified that the system was returned to service.

c. Primary Containment Personnel Airlock

The inspector observed a portion of the licensee's performance of approved surveillance procedure 7.4.6.1.3.1, "Personnel Airlock Door Seal Leak Test". The inspector verified that required administrative approvals were obtained prior to performance of the test, that the appropriate Radiation Work Permit was used, and that testing was conducted in accordance with the approved test procedure.

No violations or deviations were identified.

7. Monthly Maintenance Observation

Portions of selected safety-related systems maintenance activities were observed. By direct observation and review of records the inspector determined whether these activities were conducted in accordance with applicable LCOs; the proper administrative controls and tagout procedures were followed; and equipment was properly tested before return to service. The inspector independently verified that the equipment was returned to service. The inspector also reviewed the outstanding job orders to determine if the licensee was giving priority to safety related maintenance and that backlogs which might affect system performance were not developing. The systems selected for maintenance observation are listed below:

a. GE SBM Switches Cam Follower Deterioration

The inspector observed performance of MWR AX7048 by the electrical shop. This MWR required the visual inspection of all installed SBM switches manufactured by General Electric to determine if any of the Lexan cam followers were deteriorated. Deterioration and cracking of cam followers had been identified by the licensee during routine maintenance being performed on a similar switch in the shop when the switch was exposed to contact cleaner. SBM switches manufactured between May, 1975 and April, 1981 have Lexan cam followers. The inspector reviewed the licensee's inspection program and preliminary results of the visual inspection. The inspector determined that the licensee's program for detection of the defective switches was adequate.

b. Fuse Block Lug Loosening

The licensee instigated an inspection and corrective maintenance program to rework fuse blocks in the control room and at the remote shutdown panel. GE has identified that these fuse blocks may experience potential loosening of the bottom lug. Loosening of the bottom lug could cause loss of power to the circuits. The plant engineering staff was responsible for the preparation and following of the program and they developed a "Special Lug Inspection Report" to provide tracking of all work. The inspector observed that work was closely coordinated with the operations staff and that the corrective action appeared adequate.

c. LPCS-P-1 and LPCS-P-2 Preventative Maintenance

The inspector observed the performance of licensee procedure 10.25.12, "A. C. Motor and Control Test" on the Low Pressure Core Spray (LPCS) pump and its associated "keep fill" pump. An "Insulation Resistance Test" was also performed in accordance with procedure 10.25.9. The inspector verified that proper administrative controls were obtained prior to initiating the work, that the procedure used was adequate to control the activity, and that measuring equipment was calibrated. The inspector also observed the preparation of the tagout for performance of this work, verified proper selection and placement of breaker and switch positions, and independently verified that the equipment was returned to service.

The inspector observed that in order for this procedure to be performed, Technical Specification Action Statement (TSAS) 3.4.9.2 was entered. The decision to enter the action statement was made after discussion among the operating staff present in the control room at the time. The inspector verified that the TSAS was adhered to.

No violations or deviations were identified.

8. Power Ascension Test Program

The inspectors examined equipment, interviewed personnel, and reviewed records and procedures relative to conduct of the power ascension program described in Chapter 14 of the FSAR. The inspector examined the "Apparent Test Results Form" for each of the tests conducted under test condition #2, and interviewed the test director who presented this data to the Plant Operations Committee on August 8. The test results were approved by the POC and the plant manager, and appeared consistent with the requirements of Table 14.2.4 of the FSAR, and related level 1 and level 2 acceptance criteria. The inspector also reviewed selected aspects of the initial supporting data, such as the graphs from the computer technical data acquisition system (TDAS) for the pressure relief valve, generator trip, loss of power, and control rod drive tests.

a. Turbine Generator Trip Tests

The generator load rejection within bypass valve capacity was conducted August 7, and discussed briefly in NRC inspection report 84-18. During this report period the inspector examined the completed "Acceptance Criteria Evaluation" forms of the test procedure, and verified compliance with the FSAR criteria. Some of the criteria were not applicable to this test condition, since the test was run at 25.2% thermal power (less than 50%). No flooding of steam lines occurred (reactor water level remained below 43" from instrument reference), electrical loads transferred as expected, no reactor scram occurred, no relief valves lifted, bypass valves handled the full steam flow, and no automatic RCIC nor HPCS actuation was needed or occurred.

Although not required for this test condition, predicted values of reactor vessel dome pressure and simulated heat flux were derived from the FSAR accident analysis section curves (Figure 15.2-1 of Amendment 23) and included in the licensee's evaluation sheets. A 5% heat flux rise and 125 psi pressure rise were defined for full power operation; a 3.5% heat flux rise and 37 psi pressure rise were experienced for the actual test condition (which was not at full power conditions). The incorrect inclusion of the criteria, and superfluous inclusion of the test data was apparently not recognized by the test engineer, his supervision, nor the full time onsite General Electric Company consultant staff. The power ascension test program does not include a formal "checking" of calculations by second persons. The POC did not have an opportunity to identify this matter, since the "Acceptance Criteria Evaluation" sheets are not provided to the POC for review. Acceptance criteria are, rather, provided to POC in abbreviated form in the "Apparent Test Results" forms. The plant manager stated that more detailed test data are not required by the POC at this time. He also noted that formal checking of test program calculations is not a regulatory requirement, and that existing informal reviews of test results are adequate. The case of the superfluous, incorrect evaluation information had no impact on the conclusion of acceptability of the test. Similarly, the previously identified error in manual calculations of core thermal power (NRC report 84-13) was of little consequence. However, NRC review of test results will consider associated calculations more carefully in future inspections (84-22-03).

b. Loss Of Power Test

The loss of turbine generator and offsite power test was conducted August 7, in the early morning of the graveyard shift. Extra crews of operators and engineers were present to observe individual system reactions. The plant was at about 30% power level at the time of the trip. All backup diesel generators started successfully, and electrical busses were loaded as anticipated. Little perturbation of reactor level and pressure occurred. The RCIC was manually used to control reactor level. No automatic HPCS injection was called for nor did it occur. Test level 1 acceptance criteria were achieved.

The inspector independently verified several prerequisites and initial conditions described in the applicable plant procedure No. 8.2.31 Revision 1. The licensee was observed to have completed all prerequisities and cautions, initiated computer data acquisition, and tended to the required data sheets. Appropriate crew briefings, and review of procedures for anticipated plant response appeared to have been conducted. The crew performance was orderly and appeared to be thorough in checking and resolving all annunciators which occurred. Minor problems experienced (such as grounding indication of 250 VDC system) were identified and promptly addressed.

c. Core Performance Tests

The inspector reviewed thermal limits computer calculations for compliance with the criteria of FSAR section 14.2.12.3.19, and interviewed the shift technical advisor relative to the data. For test conditions 2 and 3, the following conditions were achieved:

TC#2	974MWT	TC#3	2478 MWT
MLHGR=	5.24	MLHGR=	9.30
MCPR=	3.021	MCPR=	1.898
MAPLHGR=	4.46	MAPLHGR=	8.11

d. Pressure Relief Valve Testing

The inspector observed portions of the relief valve performance testing on August 7, in preparation for the loss of power test. The bypass valves responded positively as each valve was individually closed. Acoustical monitors were checked by instrument technicians to determine gain adjustment factors. Tail pipe temperatures were also monitored to ascertain closure of each valve. Test results were held open (with POC concurrence) pending higher-flow calibration data for the bypass valves at the test condition 3. The preliminary test results appeared acceptable.

No violations or deviations were identified.

9. Special Inspection Topics

The inspectors examined records, interviewed personnel, and inspected plant conditions to determine training materials accuracy relative to actual plant conditions. This included attendance at two days of training classes for an operations crew "A", and one day for equipment operators.

The training classes used actual plant spare hardware for visual aids, and discussed specific applications in the plant. Five specific applications selected were based upon operations and maintenance personnel requests for training in those items, or instructor selection as topics to illustrate complex or often used principles. Handout material appeared to correspond to actual plant configurations, and class attendees did not identify any inaccuracies based upon their experience in the plant.

The training classes included four plant modifications (i.e. Enclosure Tab 9 of the August 31, 1984 letter to NRC, GO2-84-0490). The Plant Training Coordinator has logged and compiled copies of such plant modification records (PMRs) issued since fuel loading, and has commenced reviews of these for training needs. Such review is described in procedure 1.4.1 for plant modifications. Some of these PMRs had been reviewed, and provided to the corporate training group for consideration; however, the training group had not maintained records of those received and acted upon. At the time of the inspection, the training group was organizing a working filing system and a tracking log system to assure that training material and the simulator are revised as necessary relative to such plant design changes; this system was not yet in place. Also, corporate procedures had not yet been issued, although they were apparently under development, to describe how the training department would conduct its program, such as illustrated by the PMR situation. Existing procedures did not establish goals and peformance standards for timing of incorporation of plant changes into training material. Issuance of the training department procedure, completion of the PMR handling system, and action on backlogs are jointly an unresolved matter. (84-22-04)

The simulator group has provided simulator change request forms for any personnel, including operators working/training on the simulator, to identify problems such as discrepancies with actual plant hardware, or simulator behavior inconsistent with actual plant experience (software problems). An extensive backlog of such items has been compiled. This backlog has been prioritized to emphasize those matters relating to training for operator license examinations.

The mechanics for identifying required changes appeared adequately developed, although the licensee had allocated limited resources for achieving such upgrading. There appeared to be no performance standards defined for incorporating such individual changes into the simulator (however, general program goals and schedules have been defined for general upgrading of the simulator to actual plant configuration).

The inspector selected one engineered safety feature for detailed review of training material; the main steam isolation valve leakage control system (LCS). Provisions of the FSAR, system procedures, surveillance procedures, controlled system drawings, and actual hardware were compared to the "WNP-2 Requalification Program" manual chapter on this system. The manual was dated May 1983, and contained 10 pages devoted to the LCS. It contained the following discrepancies (licensee management representatives stated that setpoint discrepancies were of little significance, particularly at this time of the power ascension program where setpoint values are in many cases being adjusted and revised):

a. The LCS discharge was shown into the reactor building space, whereas the actual plant configuration, and plant drawings, showed a plant change to connect the discharge directly to the standby gas treatment equipment.

b. The heater trip setpoint was described as 225 F, whereas the actual setpoints of 300 F were identified in the calibration procedure 7.4.6.1.4.25.

c. The fan isolation setpoint of 55 scfm and 250 seconds was not consistent with the actual setpoint of 50 scfm in procedure 7.4.6.1.4.22, and the 10 minute timer shown on drawing E519 Sheet 30. Additionally, plant procedure 2.2.6 "Main Steam System" was also found to describe a 150 second isolation, (although apparently in error, this setpoint is not used directly by the operators, in that it is an automatic feature set by instrument technicians).

The accuracy of plant training manuals will be further reviewed during future inspections. (84-22-05)

No violations or deviations were identified.

10. Licensee Actions on Previous NRC Inspection Findings

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

a. (Closed) Followup item (84-09-07) - Plant surveillance procedure 7.7.0 did not include certain area temperature limits identified in the technical specifications.

Procedure 7.7.0 Revision 6 has now been issued with the appropriate criteria included.

b. (Open) Followup Item (84-15-01) - During a team inspection, observations were made that senior licensee management had not been observed in the plant during the course of the inspection.

During the current period, the resident inspectors have routinely observed senior management in the plant, including corporate technical and general managers and directors. Attendance at the daily morning plan of the day meetings included every onsite supervisor, and often a corporate manager. Senior plant management was observed intimately involved in the plant at troubleshooting activities for significant equipment.

11. Management Meeting

On August 31 the inspectors met with the plant manager and his staff to discuss a summary of the inspection findings for this period. Attendees at this meeting included the plant department managers, and other identified (*) in paragraph 1. Additionally, approximately weekly the senior resident inspector met with the Plant Manager to discuss inspection issues and NRC interfaces. The inspector met with the department managers weekly to discuss inspection issues requiring detailed records or interviews.