U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No.	50-397/88-24
Docket No.	50-397
License No.	NPF-21
Licensee:	Washington Public Power Supply System P. O. Box 968 Richland, Washington 99352
Facility Name:	Washington Nuclear Project No. 2 (WNP-2)
Inspection at:	WNP-2 Site, Benton County, Washington
Inspection conducted:	August 22 - September 2, 1988

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Approved By: SJA — 11-15-88
S. A. Richards, Chief, Engineering Section — Date Signed

Inspection Summary:

Inspection on August 22 - September 2, 1988 (Report No. 50-397/88-24)

Areas Inspected: A special, announced team inspection of operations, maintenance, engineering and QA activities as they relate primarily to the EDG system and the Nuclear Steam Supply Shutoff System.

Results:

General Conclusions and Specific Findings:

1. Control of work activities and operations is weak resulting in activities being conducted and documented in an informal manner.

2. Plant problems are not being adequately identified at the working level.

3. The followup of identified plant problems is not aggressive.

Additionally, see Appendix B, Areas Inspected and Results

Summary of Violations Identified:

1. Failure to follow procedures when revising a surveillance procedure.

2. Failure to report to the NRC two Reactor Protective System actuations.

3. Failure to follow procedures in reterminating electrical connections during maintenance.

4. Failure to promptly determine the affect of the out of calibration status of testing equipment.

Open Items Summary:

Four new items open, none closed.

DETAILS

1. Persons Contacted

a. Washington Public Power Supply System

*C. M. Powers, Plant Manager
*R. L. Webring, Manager, Assistant Maintenance
*A. L. Oxsen, Assistant Managing Director, Operations
*J. W. Baker, Assistant Manager, Nuclear Plant
*M. R. Wuestefeld, Supervisor, Plant Engineering
*G. D. Bouchey, Director, Licensing and Quality Assurance
*A. G. Hosler, Manager, Project Licensing WNP2
*L. T. Harrold, Manager, Generation Engineering
*W. D. Shaeffer, Assistant Manager, Operations Nuclear Plant
*S. L. McKay, Manager, Operation Nuclear Plant
D. S. Feldman, Supervisor, Mechanical Maintenance
E. R. Ray, Supervisor, Instrument Maintenance
T. W. Albert, Engineer, Instrument Maintenance
J. O. Cooper, Engineer, Mechanical Maintenance
S. L. Gupta, Engineer, Principal Quality Control
B. Pesek, Engineer, Systems

b. USNRC

*B. F. Faulkenberry, Deputy Regional Administrator, RV
*S. A. Richards, Chief, Engineering Section, RV

* Denotes those attending the final exit meeting on September 2, 1988.

The inspectors also contacted licensee operators, engineers, technicians, and other personnel during the course of the inspection.

2. Scope and Purpose of the Inspection

This team inspection evaluated the material condition, performance, maintenance, design modifications and operating procedures of WNP-2 as they relate primarily to two selected systems. The Emergency Diesel Generator (EDG) system and the Nuclear Steam Supply Shutoff System (NS^4) were selected by the team for review. Generic precursor data associated with the systems under review was evaluated by the team to determine if the lessons learned regarding potential system degraded performance had been addressed by the licensee.

Observations of operator performance both inside and outside of the control room were conducted by the team. Maintenance and surveillance activities were observed for compliance with written instructions and procedures, and for documentation of work which was actually performed. The material condition of the plant was assessed by comparing the as found equipment status with documented procedures, drawings, specifications, vendor data and past documented industry experience.

3. Performance of the Operating Crews

The team performed several plant tours and verified the operability of the emergency diesel generator system, reviewed the tag out log, operators' logs and verified proper return to service of components. Particular attention was given to housekeeping, examination for potential fire hazards, and fluid leaks.

The team observed that operational activities were conducted in a professional manner, and the operations staff appeared to be dedicated and displayed a good attitude towards the performance of their duties. Although the licensed operators appeared to be very experienced, the team observed a number of weaknesses in the execution of the licensee's programs. Additional definition of this concern is included in paragraphs 3.a through 3.d below:

a. Operator Logs

The team reviewed the Control Operator and Shift Manager log entries and verified that logs were being kept in accordance with Administrative Procedure 1.3.4, titled "Operating Data and Logs" (Revision 9 dated April 17, 1987), and verified that Technical Specification action requirements and mode restraints were complied with for selected safety related components. Although no discrepancies were identified, the team noted the following weaknesses:

- Entries in the Control Operator's log were often abbreviated and did not provide much detail, making subsequent log reviews cumbersome and time consuming.

- Significant plant problems and inoperable equipment which could have some impact on Technical Specification requirements were not highlighted and carried forward, such that this information was not readily available.

- A formal system did not exist for tracking inoperable equipment to assure compliance with Technical Specification action statements and mode restraints.

The team discussed these observations with the Operations Manager, who acknowledged the team's comments and stated that programmatic improvements in these areas were currently being considered.

b. Event Reports

During review of the control room logs, the team observed that the following actuations of the reactor protection system (RPS) occurred and were not reported to the NRC:

- At 0844 on May 29, 1988, during Mode 5 operation, an RPS actuation occurred during initial testing of the alternate rod insertion (ARI) system. The RPS actuation occurred when air pressure bled off the scram valves after the ARI system was

placed in the test mode and the scram air header was isolated. Although the Shift Manager's log stated that this action is normal with supply air off during the initial testing of ARI, it appeared that this conclusion was reached after the RPS actuation occurred. The team reviewed the procedure which was used for testing the ARI system (TP 8.3.94) and discussed the actuation with the cognizant engineer. The team concluded that the RPS actuation was not anticipated in the test procedure, and control rod drive air system leakage was an abnormal condition which resulted from undocumented air system leaks.

- At 1553 on August 26, 1988, during Mode 5 operation, an RPS actuation occurred when Division II RPS power was transferred from alternate to normal. The Shift Manager's log made reference to nonconformance report (NCR) 288-379, and the Control Operator's log stated that the actuation was due to switch over-travel. NCR 288-379 stated that this event was not reportable because it occurred during equipment testing. The Operations Manager stated that a similar event was reported to the NRC which had occurred on August 25 when Division I RPS power was transferred from alternate to normal. The RPS actuation that occurred on August 26 was due to subsequent testing and was not felt to be reportable. The team observed that the control room logs did not indicate that testing was in progress at the time of the RPS actuation, and the licensee could not produce a maintenance work order or other documentation to demonstrate that testing was in progress during the August 26 event.

10 CFR 50.72 requires the licensee to report RPS actuations which are not part of a preplanned sequence within 4 hours of actuation. The licensee's assessment of the reportability of these events was incorrect, and the required 4 hour reports were not made to the NRC. Failure to report these events is an apparent violation (50-397/88-24-01).

c. <u>Housekeeping/Material Plant Condition</u>

While making rounds with equipment operators and during general plant tours, the team made the following observations relative to housekeeping and material plant condition:

- The team toured the drywell during the inspection. The drywell was accessible because the unit was shutdown for an unscheduled outage. Equipment in the drywell did not appear to be well preserved in that there appeared to be excessive rust on piping and other components. Following the last scheduled outage, miscellaneous debris such as fire retardant covers, a plastic bag fashioned into a seat cushion, and a pair of goggles, had not been identified and removed from the drywell. The team also observed that a grounding cable had been left attached to one of the reactor vessel instrument nozzles. It was apparently a remnant from startup testing. The cap was noted to be missing from an electrical connector for temperature

element CMS-TE-52 used to measure upper return ring header air temperature in the drywell at the 575 foot elevation. With the exception of the rust and the grounding cable, the licensee stated that these conditions would be corrected prior to startup from the current outage.

- Felt tip pen was used extensively for component identification. In addition, graffiti was prevalent throughout the plant. Licensee management acknowledged the teams concern and stated that a program was being developed to address plant labeling. In addition, painting of the facility was in process during the inspection.

- Electrolyte levels for many of the batteries used for emergency lighting were not properly maintained. For example, batteries 441/2, 441/7, 441/8, 441/9, SWA7-1X, SWA7-2X, SWA5-6, SWA6-4, and SWS3-3 were all low on electrolyte level. The team noted that Electrical Maintenance Procedure 10.25.63, titled Emergency Lighting Inspection (Rev. 3 dated June 17, 1988) identified batteries SWA7-1X and SWA7-2X as 8-hour units required to satisfy the requirements of 10CFR50 Appendix R. The licensee stated that Electrical Maintenance Procedure 10.25.63 would be changed to include verification of proper battery electrolyte level.

- Housekeeping deficiencies outside the drywell included several instances where ladders were not properly stowed, one instance where a liquid nitrogen bottle was left on a dolly unsecured and unattended, a large accumulation of trash on the 467' level of the radwaste building, and many observations where tools were not properly stored.

- Transformer TR-7A-A (DIV 1) circuit 1M-7AA-150-1 was missing a condulet cover, and a grounding cable near MCC-8C-A was not secured.

- Handwheels were not secured on valves RHR-PI-VX-74A, RHR-PI-VX-74B and HPCS-V-69.

- Breaker indicating lights were not working for high pressure core spray (HPCS) diesel generator (DG) room fan DMA-FN-31 and HPCS DG oil transfer pump DO-P-2. The licensee stated that the indicating lights were burned out and that the bulbs were subsequently replaced to resolve the problem.

The team discussed these observations with station management, noting that a program for maintaining adequate plant material condition did not appear to have been established. Although the licensee had undertaken maintenance efforts to repair known deficient conditions and had begun to paint the power block, no comprehensive program exists to establish minimum requirements for maintaining of material plant conditions.

d. Formality and Attention to Detail

In addition to the housekeeping and material plant condition observations discussed in paragraph 2.c above, the team identified the following examples of informality and inattention to detail:

- The shift brief that was conducted by the Control Room Supervisor on August 27, 1988, included mention of a waterhammer that occurred in the residual heat removal (RHR) system. The team observed that the cognizant engineer was present in the control room evaluating this event. While making rounds with the equipment operator later during the shift, the team observed that a waterhammer occurred when RHR pump B was started. The team also observed that RHR pump B was rotating backwards for a period of time when the system was being aligned initially for operation. Although the cognizant engineer was made aware of the RHR waterhammer problem, the team observed that a log entry was not made regarding this problem and resolution of the problem was not being pursued in a formal manner. In addition, upper station management was not made aware of the waterhammer events in a timely fashion.

  In response to the team's concern over the pump shaft rotating backwards and the apparent water hammer, the licensee began an investigation which included the disassembly and inspection of the RHR pump discharge check valve. The licensee discovered during the internal valve inspection that the disk of the check valve was in the open position and did not close.

  The RHR pump discharge check valves are tilting disk Anchor Darling valves. The disk of these valves rotates about a pin, such that the disk remains in the flow stream. However, upon rotation the cross sectional area of disk which obstructs flow is reduced to a minimum. When fluid flow is reduced or stopped, the buoyant force which had been acting on the disk is reduced or removed. This would cause the disk to rotate or tilt back into the closed position.

  The check valve disk, when opened by fluid flow, is pressed against a stop which was designed to ensure the disk's center of mass is always ahead of the disk pin. Therefore the disk would tend to close based on the disk's own deadweight. During the valve inspection, the licensee discovered that the disk stop did not interrupt the disk travel until the disk's center of mass was apparently directly over the disk pin. This apparently caused the disk to become balanced on the disk pin and when fluid flow stopped, the disk did not close. In addition, the disk remained open against reverse flow which apparently occurred when the RHR pump's shaft was observed to be rotating backwards.

- When clearance order 88-8-106 was being implemented, the equipment operator could not locate a fuse that was called out as part of the clearance. The inspector observed that drawing

24E005 (Rev 7) indicated that the fuse was located in instrument rack 67, but the fuse was subsequently found in a terminal box associated with instrument rack 67. The inspector also observed that approximately 12 circuits were left abandoned in instrument rack 67, and the circuits were not labeled as to their current status. Actions were not taken by operations personnel to formally document and resolve these discrepancies.

- During emergency diesel generator (DG) #1 surveillance testing that was conducted on August 26, 1988, the inspector observed that a yellow oil-like substance was floating in the cooling water of the DG cooling water expansion tank sight glass. The inspector also observed that after the diesel was started, the governor oil levels did not drop to the sight glass midpoint scribe mark which was the nominal level specified by the surveillance procedure (a tolerance band was not specified). These conditions were not questioned and were not documented by the equipment operator.

The team discussed the above observations with the licensee. It appeared that the licensee recognizes the need for more aggressive program development and implementation. Recent changes in station management have been made in an effort to improve performance, and programmatic improvements are currently being considered.

One violation was identified as discussed in paragraph 3.b above.

4. Surveillance Activities

The team observed in-process surveillances on the diesel generator and the drywell sump flow monitor for attention to detail in following the written instructions provided and in recording the data obtained from the surveillance. There appeared to be a rigorousness by the control room personnel in following surveillance procedures. However, a surveillance and in-process trouble shooting was observed by the team for the drywell sump monitor where such rigor was not apparent.

a. Diesel Generator #1 Monthly Surveillance

On August 26, 1988, the team observed the monthly operational surveillance of the #1 emergency diesel generator (DG). The surveillance was conducted in accordance with Surveillance Procedure 7.4.8.1.1.2.1, titled "Diesel Generator #1 - Monthly Operability Test" (Rev. 11 dated August 25, 1988). Although the surveillance was performed satisfactorily, the team observed that a yellow oil-like substance was floating in the DG cooling water expansion tank sight glass. The team also observed that after the diesel was started, the governor oil levels did not drop to the sight glass midpoint scribe mark which was the nominal level specified by the surveillance procedure (a tolerance band was not specified). These conditions were not questioned and were not documented by the equipment operator (also discussed in paragraph 3.d of this report). In order to resolve the teams' concerns, maintenance work request

(MWR) AT6682 was initiated to remove any foreign substance from the DG cooling water system and the DG was started so that adjustments could be made to the governor oil levels. The licensee stated that the surveillance procedure would be changed to provide more definitive guidance with regard to the governor oil levels.

b. Drywell Sump Flow Monitor Calibration

On August 24, 1988, the team observed that instrument and control (I&C) technicians were making adjustments to the drywell sump flow monitor calibration. Procedure 7.4.4.3.1.4, titled "Drywell Sump Flow Monitors - CC" (Rev. 3, including Deviation 88-538 dated June 11, 1988), was being used to perform this activity. The licensee had determined that the flow indicated by the monitor was inaccurate. The actual flow rate from the drywell sump was being measured periodically by liquid collection techniques. The team observed that the procedure was being marked up as the calibration was being performed. There did not appear to be any administrative control of the revisions made to the procedure. The maintenance supervisor stated that there were some problems with the procedure such that the flow totalizer did not give accurate indication when the calibration was completed and that the procedure was being troubleshot and corrected as part of the calibration activity that was currently being performed. When questioned, the Shift Manager stated that he was not advised of the changes that were being made to the calibration procedure.

The licensee's Administrative Procedure 1.2.3, titled "Use of Procedures" (Rev. 12 dated September 18, 1987), requires procedures to be followed in the performance of plant activities. When procedures cannot be followed, a revision to the procedure or a procedure deviation must be completed. In the case of a procedure deviation, documentation prior to its implementation is not required providing the deviation has been approved by two members of plant management/supervisory staff, and the Shift Manager is of the opinion that the work must continue. During calibration of the drywell sump flow monitor, these administrative controls were not complied with. The maintenance supervisor initiated nonconformance report (NCR) 288-373 to address the team's concern. This is an apparent violation (50-397/88-24-02).

One violation was noted in this area during the inspection.

5. Maintenance Program Implementation

a. Organization/Program

The Maintenance organization consists of a staff of approximately 210 and is directed by a maintenance manager who reports directly to the plant manager. In addition to the normal complement of craftsmen and supervisors, the organization includes groups of maintenance engineers who provide both technical and work coordination support to the individual craft groups. The maintenance engineers are the principal developers of the work

instructions and work package planning sheets which identify the critical elements of a maintenance effort. In an effort to provide stronger direction and improve the quality of the maintenance work at the plant, reassignments were recently made in the positions of maintenance manager, assistant maintenance manager and mechanical maintenance supervisor.

The systems for identifying, controlling, documenting and determining work requirements are established in plant procedure 1.3.7, "Maintenance Work Request" (MWR). During the review of this procedure, the team noted that a maintenance work procedure is not required when tightening the packing on pumps or changing a fuse when it has blown for the first time. Apparently this is considered "mundane" work and the procedure has been written to allow this work to be completed by various organizations. The team discussed this with the licensee and pointed out that the referenced items, when associated with safety related equipment, could represent a significant problem with the system (in the case of a blown fuse) or require the discipline of an operating check (tightening of pump packing) and should require the use of a maintenance request. The licensee representative acknowledged the comment and stated that this matter was already under review and subject to a program change.

The MWR procedure describes the following 3 types of maintenance work requests; a normal MWR which is intended to control a "one-of-a-kind" equipment failure, a standing MWR which is intended to control repetitive maintenance tasks, and a vital MWR which is intended to control maintenance activities on equipment which, if left unrepaired, could result in a potential Technical Specification violation, a reportable occurrence, a safety hazard, or could affect plant reliability. The quality of instructions and records associated with the later MWR type was considered to be poor and is addressed in paragraph 5.b. Additionally it was noted that the use of the vital work request exceeded the intent of the maintenance work request procedure and was routinely used even when no imminent safety problem existed.

b. <u>Document Review</u>

After reviewing approximately 20 work packages which were related to the emergency diesel generators and the containment isolation system and which were completed during the past 1 1/2 years, the team made the following observations:

1. An inconsistency in the work packages was noted in the identification of components associated with Technical Specification requirements. The MWR form contains a check box to identify the equipment on the MWR as technical specification equipment. There appeared to be a lack of formality in checking the box correctly for equipment on which work was being performed.

2. The team noted Maintenance Work Requests where work instructions to craftsmen were considered to be minimal. One case involved the troubleshooting of safety related isolation valve RCIC-V66, which is a check valve with position indication in the control room. The valve is the closest isolation valve to the reactor vessel for RCIC injection water.

   The valve had been discovered with an open indication in the control room, contrary to its required closed position. An activity had been undertaken by the licensee to establish a valve lineup which would cause a lower pressure region upstream of the check valve and thereby tend to reseat the valve.

   The record after troubleshooting the problem did not indicate the reason why the valve was open, when it should have been closed. Also, there was no indication that retesting was required. The inspector later confirmed that the valve had been retested as part of a generic surveillance test involving other isolation valves. Another case involved the repacking of RCIC-V63. The instruction stated, "Valve Leaking - Repack". No detail, procedure reference, vendor manual, or torquing requirements were listed.

3. In one case, a vital MWR involved the reassembly of the cylinder valve bridge and rocker arm assembly as well as the installation of the oil lines onto the rocker arms of emergency diesel 1A. Three torquing operations were to be performed. Due to informal communications between Quality Control (QC) and Maintenance, QC did not inspect the torquing operation in accordance with its internal guidance. The vital MWR did permit the torquing step to be bypassed if QC was not available at the time of the call to witness. However, the inspector noted that the torquing step was not performed until the next day, at which time QC was not called again to witness the step.

4. Two cases were noted where the maintenance records associated with maintenance work on the main steam isolation valve solenoid pilot valves and the RHR-V53B valve indicated that a cable involved in each of the jobs had not been reterminated. The retermination control sheet in the MWR had not been completed. The changes in the instructions had not been authorized by the Plant Manager as required by administrative procedure 1.3.9, "Control of Electrical and Mechanical Jumpers and Lifted Leads". This is considered a violation of regulatory requirements (50-397/88-24-03).

5. Three instances were noted where the evaluation and disposition of out-of-calibration measuring and test equipment (M&TE) associated with two torque wrenches and a piece of leak rate testing equipment were not completed in a timely manner. In the case of the two torque wrenches, the out-of-calibration notices had been issued in August 1987 and were still open. The out-of-calibration notice for the leak rate detection instrument also was still open and had been issued in

March 1987. The failure to complete in a timely manner the evaluation of the impact on performance of the equipment on which testing was performed using out of calibration M&TE is considered a violation of regulatory requirements (50-397/88-24-04).

6. On June 14, 1988, RHR-V-9 would not close when operated remotely from the control room. The Shift Manager initiated vital maintenance work request (MWR) AV1733 to address this problem. During subsequent troubleshooting of the valve, RHR pump RHR-P-2A tripped and nonconformance report (NCR) 288-258 was issued to address this problem. The NCR concluded that the probable cause for the RHR-P-2A failure was the initiation of a pump trip signal during RHR-V-9 troubleshooting activities. A less than full open indication from RHR-V-9 sends a trip signal to RHR-P-2A for loss of suction protection. The team reviewed vital MWR AV1733 and NCR 288-258 and made the following observations:

   - The work instructions provided on the MWR appeared to be very qualitative (i.e. troubleshoot problem), and no caution was provided regarding the potential to trip the operating RHR pump.

   - A continuation sheet was added to the work instruction after the work instruction was initially prepared, and there did not appear to be any administrative controls governing this type of change to a MWR. The work performed section of the MWR did not include documentation of the date and time when the work was started.

   - RHR-P-2A tripped on June 15, 1988, at 1253. Work associated with MWR AV1733 was completed on June 14 at 1605. The licensee's conclusion documented on NCR 288-258, which indicates that RHR-P-2A tripped while maintenance was being performed on RHR-V-9, does not appear to be well founded. No further root cause determination had been attempted to reconcile the apparent mismatch of dates between the MWR being completed the day before the pump trip.

c. <u>Observation of Work</u>

The team observed portions of work in progress associated with the following maintenance activities:

- Pressure decay test of the main steam relief valve tail pipe associated with valve MS-RV-2B (MWR# AT 6632).

- Replacement of a pressure switch on one of the recirculation valve controls (MWR# AT 6053).

- Repacking of the RCIC-63 valve (MWR# AV 1810).

- o Modification of the moisture separator level transmitter on the containment atmosphere control system (MWR# AT 6245).

The team noted during the observation of work that maintenance work requests had been written for the work in progress. Where measurements were being taken, instrumentation calibrations were current. QC was noted to be present when the work activity required QC presence. Radiation precautions were considered adequate for the work in progress and procedures appeared to be followed. During the performance of one maintenance job involving the repacking of RCIC-V63, the team observed that maintenance personnel were having difficulty installing the new packing into the valve stuffing box. The team also noted that the maintenance personnel determined that the packing was the wrong size and stopped the work. The problem with the packing was found to be associated with the dye used to cut the inner diameter. The dye was stamped with the wrong size. Proper sized packing was produced and the work completed. An ASME Section XI test had been identified as a retest requirement following maintenance.

Two violations were identified in this area of inspection.

6. Emergency Diesel Generators (EDG) (DG-1 and DG-2)

During the inspection the team performed a field walkdown of the EDG skids and associated support systems. These systems included, in part, the EDG air start system, EDG jacket water cooling system, governor control system, EDG pre-heat lube oil modification and service water cooling system. Verifying such items as support locations, orientation, and correct piping configurations, the team performed a limited as-built configuration inspection of the subject systems utilizing the applicable design configuration drawings. An operational test in which the team was able to observe the various operating parameters of the EDG system such as temperatures, pressures, and fluid levels, (i.e. exhaust gas outlet temperature, jacket water and lube oil pressure and levels) was also performed for EDG engine #1A1. The following is a description of the system material condition, any observations or deficiencies noted, and the potential impact the deficiencies could have on the safe and reliable operation of the system. Also included is a description of the licensee's corrective actions for the deficiencies identified during the team's walkdown of the EDG systems.

a. EDG Starting Air and Servomotor Pneumatic Tubing Lines

During the inspection the team performed a limited as-built configuration inspection of the EDG pneumatic tubing lines which supply air to the starting air motors, the servomotor, and associated starting air piping and components. During an emergency start actuation, a solenoid valve is energized, allowing air from the starting air tanks to pass through the solenoid valve to the pinion gear end of the starting motors. The entry of air through the pneumatic tubing lines moves the pinion gear forward to engage with the engine ring gear. In addition to maintaining gear engagement, the air opens the air start valve, releasing the main

starting air supply. Starting air passes through the air start valve and into the flexible hose assembly attached to each air starting motor. The multivane starting motors drive the pinion gears, rotate the ring gear, and crank the engine.

During the starting sequence, at the same time that starting air is applied to the starting motors, air is also applied to the bottom of the governor booster. This drives the booster piston up, forcing oil under pressure into the governor. The governor power piston is moved in the "increase fuel" direction and fuel is supplied to the injectors for starting the engine. The EDGs are supplied with two redundant banks of air start motors and servomotor shuttle valves.

During the field walkdown, the team identified approximately 20 feet of the pneumatic starting air line on EDG engine #1A1 to be unsupported and noted that additional spans of tubing appeared to be unsupported on the other EDGs as well. The team identified this condition to the licensee's design engineering staff and to the EDG system engineer to determine if there were any analyses or documentation indicating that the existing condition was acceptable. The licensee personnel were unable to present the team with an analysis that the existing condition met the design criteria for allowable tubing stress. Licensee personnel were also unable to identify any design control documentation specifying the location of the required vibration/seismic supports for the pneumatic tubing lines. A postulated failure of these lines (if left unsupported) could potentially result in a loss of starting air to the EDG or a loss of air to the servomotor during normal vibration or during a seismic event.

The licensee performed the following corrective actions. The licensee issued plant deficiency report No. 288-380 which documented the as-found condition of the starting air pneumatic tubing. The immediate disposition of the plant deficiency report recommended, in part, performing an analysis to demonstrate the ability of the pneumatic tubing to withstand a seismic event, evaluating the need to add additional supports, and requesting design engineering staff to provide design direction for the installation of the supports. As a result, the design engineering staff issued basic design change (BDC) No. 88-0299-04. This BDC included the installation and qualifying stress calculations with references to the analyses assessing the as-found condition of the starting air pneumatic tubing. The analyses affirmed that no seismic induced failure would have occurred for the worst case as-found condition. However, prior to the conclusion of the inspection, design engineering did provide design direction for the installation of additional supports to improve seismic capability.

b. EDG Cooling Water Pipe Coupling

During the field walkdown of the external EDG cooling piping on EDG-2, engine 1B1, the team identified that safety-related flex coupling No. DLW FLX-11B1, located on the cooling water line between the engine and thermostat valve on the auxiliary skid, was misaligned approximately 5.5°. The team identified this condition to the licensee to determine if there had been any analyses performed or documentation reflecting that the existing condition was an acceptable installation. The licensee personnel stated that this condition may have resulted from the R-1 outage in July of 1986, when it was noted that EDG engines 1A and 1B were not doweled (aligned) in accordance with the EDG manufacturer's recommendations. The licensee also stated that the original EDG alignment problem had been corrected and documented per plant modification record No. 02-86-0329-0. However, licensee personnel were unable to demonstrate that the present excessive angularity of the cooling water flex coupling was acceptable.

Because a postulated failure of the flex coupling during a seismic event could result in the loss of EDG cooling water and potentially render the EDG inoperable, the licensee performed the following actions. The licensee first performed angularity field measurements on the flex coupling and determined the maximum angularity to be 5.5°. The licensee also measured the length of pipe insertion into the flex coupling to assure that the minimum insertion criteria of 1.86 inches had not been affected due to the excessive angularity. Upon review of the manufacturer's (Airoquip) catalog, the licensee determined that the coupling's as-found condition was outside the manufacturer's maximum angularity criteria of 4°.

Upon disassembly of the coupling in the field, the licensee discovered that the actual minimum insertion was 1.66 inches or .2 inch less than the manufacturer's stated minimum. This situation was discussed with the licensee and the manufacturer, and was determined to not render the EDG inoperable for the following reasons:

1. The 1.66 inch penetration into the coupling is sufficient to provide a good contact surface between the gasket on the end of the coupling and the pipe. The end of the pipe is far enough beyond the gasket not to interfere with the seal.

2. The application normally involves no pipe movement or very small, infrequent movement of the piping. Consequently, even if contact had been made between the end of the pipe and the coupling wall, the movement would not have been expected to wear the coupling wall to an extent that the coupling would have failed.

3. The coupling is designed for 150 psig internal pressure but operates at approximately 10 psig.

The licensee reinstalled the flex coupling to meet the required angularity and insertion criteria as specified in the manufacturer's catalog and documented the as-found condition per plant deficiency report (PDR) No. 288-382.

c. Bent Cooling Water Vent Line Nozzle

While performing a limited as-built configuration inspection of the external EDG cooling water piping for EDG 1A1 and 1B1, the team identified two bent nozzles (1/2 inch x 4 inches long) on diesel cooling water (DCW) tanks 1B1 and 2B1. It appeared that the nozzles were bent 1/4 inch off center (worst case) as a result of being stepped on while personnel were performing various work activities in the EDG rooms. This condition had not been previously identified in the licensee's problem identification tracking system. The nozzles were associated with the EDG cooling water vent lines, and failure of the nozzles could result in a loss of EDG cooling water, potentially rendering the EDG inoperable. The licensee performed the following corrective actions. The licensee performed a field walkdown of all associated cooling water vent lines and performed field measurements to determine which DCW tank nozzle was most affected. The licensee also issued plant deficiency report (PDR) No. 288-392 to document the deficiency and performed a calculation to assess the (worst case) existing condition. It was determined in the calculation that the bend was on the 4 inch vertical lead of pipe (tank nozzle) because this section of piping consisted of sch. 40 pipe while the rest of the associated piping is sch. 160. It was also determined that there was no deformation near the DCW tank weld and since the weld is a full penetration weld, non-destructive examination of the weld was not required. The disposition of the PDR and calculation was that the slight bend in the DCW tank nozzle had no effect on the serviceability of the pipe.

d. Service Water Valve No. SW-V-4A

During a field walkdown of DG room DG-1, the NRC inspectors identified an incomplete thread engagement condition on the packing gland nuts for safety-related, 8-inch line, motor-operated service water valve No. SW-V-4A. The team identified this condition to the licensee to determine if there was any documentation reflecting the existing condition. The licensee was unable to present any documentation which reflected the existing condition. However, because of the potential for a loss of service water which is used as secondary cooling for the EDG jacket water and lube oil systems, the licensee performed the following corrective actions. The licensee issued maintenance work request (MWR) No. AT 6667. The MWR work instructions stated in part to (1) obtain clearance for work, (2) remove all necessary packing to obtain proper thread engagement, (3) repack SW-V-4A per maintenance procedure No. 10.2.7, and (4) ensure SW-V-4A stokes manually with proper thread engagement. The NRC inspectors were notified that the work was performed prior to the conclusion of the inspection.

e. Deformation of EDG Support Footings

During the field walkdown of EDG skids and associated components, the team identified a deformed support footing on the east side of engine 1B2. The team identified this condition to the licensee personnel to determine if there was any documentation reflecting the existing condition. The licensee stated that the deformed support foot had been documented upon receipt inspection (material damage report No. B-022 dated December 13, 1978) and was dispositioned accept-as-is, touch up with paint as required. However, after a secondary visual inspection of the subject support foot and the discovery of an additional deformed foot on the west side of engine 1B2 by the team, the licensee performed the following additional corrective actions:

The licensee issued plant deficiency report (PDR) No. 288-393, which stated in part that the condition was caused by an excessive load being placed on the jacking screws which were used to obtain the proper alignment for the EDGs. The PDR further stated that the operations and maintenance manual would be modified to warn personnel performing EDG alignments to exercise care in using the jacking bolts, such as not to deform the support footings. The licensee also performed mechanical evaluation (M.E.) No. 02-88-58 for the west support foot which was determined to have the worst case deformity. The evaluation stated in part that based on the engine alignment, bolting arrangement, visual weld examinations, the use of gusset plates on either side of the support footings, and previous main bearing examinations which showed no perceptible wear, it was concluded that the support footing deformations appeared to be localized, and would have no effect on the serviceability of the engine.

f. Missing Support on Lube Oil Circulating Pump Suction Line

The team performed a limited as-built configuration inspection of a vendor recommended modification (MI 9644), which the licensee had implemented on the high pressure core spray diesel engine and all four EDG engines. The purpose of the modification is to provide an improved immersion heater lube oil circulating system that will consistently supply lube oil to the engine's turbocharger and crankshaft in anticipation of an emergency start.

During a walkdown of the emergency diesel engine 1A1 modification, the team identified a missing seismic support bracket on the lube oil circulating pump suction line. The team identified this condition to the licensee to determine if there was any documentation reflecting this condition. The licensee presented the team with as-built configuration drawing No. 02-332-002 which identified the support as part of the modification (item 90). However, because the support was missing on engine 1A1, potentially affecting the seismic capability of the lube oil piping, the licensee issued PDR No. 288-393 to document the condition. The immediate disposition of the PDR stated that, based on a span chart criteria (ANSI B31.1) the missing seismic support would not affect

the seismic qualification of the suction line. The licensee also performed a physical inspection of the subject line and installed the support per maintenance work request (MWR) No. AT 6629 prior to the conclusion of the inspection.

g. EDG Governor Lube Oil Level

During a walkdown of the EDG skid for engine 1A1, the team noted that the lube oil level in the external sight glass for the EDG governor was out of sight high with the EDG in the standby mode of operation. The team also reviewed the station EDG surveillance procedure No. 2.7.3-7 (Step 15) and was unable to determine the required governor oil levels during standby or normal operation of the EDG. The team identified this concern to the licensee to determine what criteria the equipment operators were utilizing for the governor lube oil levels, while performing their surveillance inspections of the EDGs and high pressure core spray engines. The failure to identify a high oil level in the governor during operation could potentially result in foaming of the lube oil causing erratic operation of the engines.

On August 25, 1988 the licensee contacted the EDG governor manufacturer (Woodward Governor) via telephone for guidance on determining the optimum governor oil level for standby and normal operation of the engines. The EDG governor manufacturer recommended that the governor oil level be monitored, and if needed, be adjusted after the engine has been operating for such a time span that the engine is warm. The governor manufacturer further stated that the the intended normal governor oil level be determined (via the external sight glass) with the engine running.

As a result, the licensee performed an operational test of EDG 1A1 to assure that the governor oil level dropped within tolerance during operation. Excess oil was drained so that a level could be observed in the external sight glass during normal operation of the engine. The licensee also revised the station surveillance procedures prior to the conclusion of the inspection.

h. Vendor Manual Review

The licensee's emergency diesel engines were manufactured by General Motors, Electromotive Division (EMD). The diesels are 20 cylinder turbocharged engines. There are two diesel engines driving each emergency generator. The inspector reviewed the vendor manual recommendations applicable to the diesel engines, and made the following observations:

- The vendor manual stated that the governor oil level should be checked and adjusted to the midpoint scribe mark in the sightglass shortly after the diesel is started. As discussed above, the licensee's surveillance procedure did not provide specific instructions in this regard.

- For the oil fog lubricators located upstream of the air start motors, the vendor manual specifies an oil drip rate which is dependent on the nominal air velocity through the air start piping. The licensee's procedures did not address this vendor recommendation.

Based on the team's observations, it appears that the licensee has not established a program to address and implement (as appropriate) vendor recommendations. Licensee personnel could not identity where the vendor recommendations had been incorporated. However, they would evaluate the recommendations for possible insertion into the appropriate procedure.

Because the above identified concerns did not result in a direct safety issue and because it would be difficult to determine the cause of the deficiencies in most cases (ie, construction activities versus recent operational activities), the team did not consider enforcement appropriate. However the number of discrepancies noted does indicate that licensee personnel need to be more aggressive in identifying and documenting discrepancies.

7. <u>ASCO Solenoid Valves Used Within Nuclear Steam Supply Shutoff System (NS^4)</u>

During the inspection, the team reviewed the licensee's evaluation of NRC information notice No. 88-43, entitled "Solenoid Valve Problems." The information notice was issued to alert licensees to a series of solenoid valve failures that have occurred at several nuclear power plants. The notice discussed in part various licensee investigations which isolated the cause for two main steam isolation valve (MSIV) failures to Automatic Switch Company (ASCO) Model NP 8323AZOE dual solenoid operated valves (SOVs). The failure mechanism(s) could not be positively identified. However, the most likely cause of the two failures was determined to be, in part, a degradation of the ethylene propylene diene monomer (EPDM) elastomer seats, due to exposure to high temperature environments, and a yellowish sticky film which acts like an adhesive and prevents the core assembly from shifting to the de-energized position, and which lies between the core assembly and plugnut assembly of the solenoid valve. It was later stated that the film substance closely resembled the Dow 550 lubricant with which ASCO routinely lubricates the core and plugnut assemblies to reduce noise and wear associated with a 60 cycle hum.

In discussions with the licensee, the team discovered that WNP-2 had experienced one failure of their MSIVs during testing and had established an extensive program to determine the root cause of the problem. The licensee attributed the cause of the failure to be sticking of the "A" or upper core assembly of a SOV. Two analyses, one in-house by licensee personnel and another by an outside consulting firm, were performed. The analyses were based on SOV internal scrapings which were found to be primarily silicon in nature. The licensee concluded that the sticking of the "A" core assembly was associated with the Dow 550 lubricant. The licensee then issued a maintenance work request to reinstall all new MSIV solenoid control valves without the Dow 550 lubricant and is presently operating with the MSIV solenoid valves in this configuration. When the licensee notified the solenoid valve manufacturer of their conclusion,

the manufacturer stated that they did not concur with that postulated failure mechanism.

The licensee stated that the manufacturer indicated that there was a possibility that the lower exhaust core assembly was sticking due to the introduction of hydraulic fluid leaking back through the air lines from the MSIV closure control mechanism. The licensee's engineering opinion is that due to the torturous path the hydraulic fluid had to follow to be introduced into the lower exhaust core assembly, this possibility appeared to be unlikely. The licensee's engineering analysis appears to be adequate and supported by chemical analysis of valve internals residue.

Trouble-shooting was initially performed on the solenoid valve, however, the licensee had not required a controlled disassembly in the field. This effort, had it been performed, could have preserved any evidence of hydraulic fluid within the piping system.

8. Design Process Review

The licensee's design processes were evaluated for technical accuracy and attention to detail. Three (3) Plant Modification Requests (PMRs) and their associated Design Change Packages (DCPs), Field Change Requests (FCRs), and Maintenance Work Requests (MWRs) were reviewed for plant modifications to the Nuclear Steam Supply Shutoff System (NS^4) and the Emergency Diesel Generators. In the design packages, no discrepancies which had not already been addressed by the licensee were identified. However, some activities associated with the design packages exhibited weaknesses where designs were being performed or documented in an informal manner.

a. PMR 02-85-0466-0 RWCU Surveillance Test Switch

Design package DCP 85-0466-0A was generated to install test switches to enable the performance of surveillance testing of the reactor water clean up (RWCU) delta flow function without the use of temporary jumpers. The design package contained both drawing changes and wire termination lists. These two items did not agree with each other, i.e., the drawings were correct but the wire termination lists were incomplete and inaccurate. The wire termination lists were corrected by the technical staff with a DCP revision (DCP 85-0466-0B). The design engineer prepared the revised DCP with the wiring list corrections. However, the package was not released since engineering procedures do not require the wire termination lists to be a part of the controlled design package. The wire termination lists, however, are required in the MWR and therefore the lists corrected by the technical staff were included in the MWR. The maintenance department reviewed the wire termination list and discovered that the termination lists were still incomplete. Maintenance personnel made further corrections to the wire lists. The team's concern was that the wire termination list is required to be contained within the MWR. However, there is apparently no clear procedure requirement for someone to generate

the document. In addition, for this DCP review, it was not clear that revisions made to the wire termination list were checked.

Licensee management acknowledged the concern and stated that the wire termination list would be required by the appropriate procedure.

Although the test switches have been installed and operate as intended, the informal design and documentation process left areas where mistakes and errors could have been made. Since engineering and the technical staff only receive the cover sheet of the MWRs, they had no indications that the scope of the corrections to the wire termination lists had changed from the DCP.

b. PMR 02-85-0383-0 Diesel Engine Governor System

Design packages DCP 85-0383-0A and DCP 85-0383-0B were generated to replace the diesel engine governor controls with an electronic governor allowing the diesels to be operated at a slow idle. The design was intended to be a vendor supplied "black box" replacement for the old governor controls. This apparently simple plant modification required 2 DCPs and 15 FCRs to complete. Of the 15 FCRs, at least 9 could be attributed to errors, omissions, or incompleteness of the design. Furthermore, a licensee QA audit (Surveillance Report 2-88-203) identified 6 deficiencies and 14 observations associated with the design and installation of this work package.

These examples are indicative of a less than rigorous approach to the controls placed on the development and implementation of design packages for plant modifications. The licensee has recently committed to improving their program for design changes. Since no design activities were reviewed which would have been developed under the new programs, it can not, as yet, be determined if the weaknesses observed by the inspector have been addressed or eliminated by the licensee.

9. Plant Oversight Groups

The team examined the involvement of the licensee's oversight groups in formulating corrective actions in response to internal and external events having potential safety significance. To determine the effectiveness of the oversight groups, the review considered initiatives of the groups and ultimate corresponding actions of the licensee. The team generally found the work of the review groups to be thorough. Instances were found where followup of review group findings was incomplete.

a. Nuclear Safety Assurance Group

The Nuclear Safety Assurance Group (NSAG) functions to examine unit operating characteristics, NRC issuances such as bulletins and notices, industry advisories, Licensee Event Reports, and other sources of unit design and operating experience information (including units of similar design) which may indicate areas for

improving unit safety. The NSAG makes detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities, or other means of improving unit safety. NSAG reports to the Director of Licensing and Assurance. Specific requirements for the group are set forth in Technical Specification 6.2.3. The licensee's procedures under which this group operates are found in PPM 1.10.4.

The team looked at NSAG's reviews of events on emergency diesel generators and on nuclear steam supply shutoff system (NS^4) components. The number of reports on external events reviewed by NSAG is large. There were roughly 100 events reviewed on diesel generators and roughly 40 reviewed on NS^4 components.

The team examined NSAG reports on a representative number of events. The analyses were found to be thorough and the recommendations for action were clear and concise. NSAG recommendations are subject to review, and thus modification, by other organizational units prior to implementation. However, the team found that the NSAG recommendations were well respected and any modifications appeared to have rational bases.

Although NSAG maintains cognizance of their recommendations through ultimate disposition, the team noted that a small percentage of items were lost from the tracking system without documentation of closeout and furthermore were apparently not implemented. For example, in a report dated November 26, 1984, NSAG recommended increasing the air receiver capacity of the air start system for the HPCS diesel generator in order to improve reliability. Subsequently, engineering recommended an alternative for achieving the improvement in reliability. The recommendation is no longer in the NSAG tracking system. However, no action was taken to improve diesel generator reliability. The alternative action is on a different plant tracking system (as PMR 02 85 0093-1) but is dormant. This appears to be a defect in the tracking system rather than an indication that NSAG is not functioning. Nevertheless, to be fully effective at its function, followup of review group recommendations is essential.

b. <u>Corporate Nuclear Safety Review Board</u>

The Corporate Nuclear Safety Review Board (CNSRB) is appointed by the Managing Director from his senior technical staff and from personnel outside the Supply System. At the time of the inspection, three outsiders served on the Board. This group serves to provide independent review and audit of activities designated in Technical Specification section 6.5.2 and advises the Managing Director of their findings and recommendations from these reviews and audits.

The team reviewed the minutes from the last four regularly scheduled quarterly meetings of the CNSRB (meetings 87-11, 88-01, 88-07, and 88-09). CNSRB also meets intermittently as needed, for example, to review proposed changes to technical specifications. The inspection team reviewed the minutes from one recent special meeting (meeting

88-05) to gain understanding of the CNSRB input to this process. These special meetings often do not include the complete CNSRB membership. The inspector also interviewed the CNSRB Chairman and the former recording secretary.

The team found the minutes to be quite detailed and therefore very helpful in providing insight into the depth of discussion occurring at the quarterly meetings. Presumably because of the focus on the need for management involvement, CNSRB recommendations were usually directed toward longer range safety improvements involving policies, programs and procedures, rather than toward resolution of technical problems. However, recommendations generally would result in actions for operations.

The CNSRB maintains its own tracking system. The team looked at followup to recommendations made at earlier meetings. A number of the recommendations had been closed out and it generally appeared that CNSRB was making a significant contribution to safe operation of WNP-2. However, the minutes often include recommendations or commitments which are not entered into the CNSRB tracking system and do not appear to be closed out methodically by CNSRB. It appears that the effectiveness of the CNSRB could be enhanced by expanding their tracking system to capture all recommendations and commitments.

c. Plant Operations Committee

The Plant Operations Committee (POC) functions to advise the Plant Manager on all matters related to nuclear safety. Specific responsibilities detailed in the technical specifications (Section 6.5.1) essentially include review of changes to hardware or procedures having potential safety ramifications, review of events which may convey safety lessons, and review of operations to detect potential safety hazards. The technical specifications require monthly meetings to address these matters. However, the POC has found it necessary to schedule regular weekly meetings and frequently holds additional meetings to discharge its responsibilities.

The team reviewed minutes from POC meetings for most of the past year and attended one POC meeting. The team also talked with POC members about POC procedures. POC maintains their independent tracking system for followup of certain specified action items.

Review of the minutes, as well as observations at the one meeting attended, indicate that the POC meeting agendas are dominated by the mandatory reviews of design and procedural changes, of licensing actions, and of event reports. In order to accommodate the large number of such actions to be acted on by POC, coordination problems and technical and safety concerns must be resolved before the meeting. Discussion of these items is minimal at the meetings. Meeting minutes often are limited to identification of the items acted upon with indication of the action taken. Nevertheless, it

would appear that the formality of the POC process for approval of these items results in resolution of safety concerns.

Review of the POC minutes also sought records of discussion of unit operations and of evolving operational problems to identify and determine the effectiveness of the group in advising the Plant Manager of pending safety concerns. Specifically sought out, for example, were minutes of meetings addressing drywell leakage and drywell temperature problems, both before and after the recent refueling outage. The minutes were brief, but gave the general impression that the discussion at POC centered around solving the immediate complex technical problems, rather than on the safety ramifications of the problems and alternative solutions.

An unexpected plant shutdown early in the inspection period afforded the team an opportunity to enter the drywell. The team noted that some outage work areas apparently had not been cleaned up prior to restarting after the last refueling outage. Because of the role of the POC in implementing the restart plan, the POC minutes for meetings near the end of the outage were reviewed. Minutes for the June 1988 POC meeting (#88-22.2) which reviewed the containment closeout inspection, indicated that housekeeping efforts were still in progress but would be completed prior to restart. This was not an item for the POC tracking system and was not addressed in subsequent minutes prior to startup.

Based on the team's review of POC documentation, it is not apparent that the POC had addressed the long term safety implications of the drywell leakage and temperature problems or the drywell cleanliness prior to restart. No documentation which addressed the long term effects of the higher than normal temperature of the drywell on electrical equipment environmental qualification was found.

Drywell cleanliness problems were reviewed by the POC during the committee's review of startup requirements. However, no followup action appeared to have been taken by the committee to ensure acceptable drywell cleanliness standards were met.

The licensee acknowledged the team's concern and stated that the POC appears to become involved in problem solutions rather than review and oversight functions.

d. <u>Quality Assurance Activities</u>

The team examined quality assurance activities in conjunction with modifications to the diesel generators and to the NS^4. The team also reviewed a recent audit more broadly addressing design modifications and associated activities (Audit 88-434) prepared by the Corporate Licensing and Assurance staff. The inspection considered the scope of the QA review, as well as actions taken in response to QA findings, to ascertain the effectiveness of this review group on plant safety.

Audit 88-434 made a number of findings regarding design modifications which demonstrate the thoroughness of their examinations as well as their willingness to be candid to their management regarding their results. A number of their findings focus on problems identified in previous NRC inspection reports (87-19 and 88-02). In accordance with licensee procedures, the organization whose work areas were audited was to respond to the audit, identifying actions to be taken to correct deficiencies noted in the audit.

The effectiveness of the audit activities will not be determinable until corrective actions have been fully implemented. Audit responses addressed specific plant components called into question by the audit, and corrective actions were taken where appropriate. Additionally, a number of procedural changes were identified in responses to the audit. Procedural improvements should enhance performance of future design modifications.

The team expressed some concern with follow up to audit findings by the audit group. Licensee procedures resulted in an audit being closed out on the basis of responses received. Thus specific audit findings are not tracked by Corporate Licensing and Assurance. For example, the inspector noted that at least one item appeared to have been dropped without significant procedural changes being considered. Quality Finding Report No. 4 stated that failure of design engineers to visit a jobsite may have contributed to design deficiencies. In response to this finding, the existing policy for walkdowns was restated. Although subsequent discussions with the licensee have provided additional insight on the particularities of the deficiencies referenced in the audit, it remains to be demonstrated that walkdowns are being utilized effectively to produce quality design modifications.

Based on a review of records the licensee supplied, it is not apparent that recommendations of the oversite groups are adequately tracked through implementation. This may result in some recommendations being dropped or deferred without formal documentation. In some instances, discussion with plant management identified additional resolution, although little documentation had been generated by the plant to support the closeout of the issue.

10. Exit Meeting

On September 2, 1988, an exit meeting was held with the licensee representatives identified in paragraph 1. The team summarized the inspection scope and findings as described in this report.