APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION V

Inspection Report:	50-397/94-04
Operating License:	NPF-21
Licensee:	Washington Public Power Supply System P. O. Box 968 Richland, WA 99352
Facility Name:	Washington Nuclear Project No. 2 (WNP-2)
Inspection At:	WNP-2 site near Richland, Washington
Inspection Conducted:	January 11 - February 21, 1994
Inspectors:	R. C. Barr, Senior Resident Inspector D. L. Proulx, Resident Inspector S. P. Sánchez, Resident NRR Intern D. E. Corporandy, Project Inspector (1/31-2/4/94) D. F. Kirsch, Technical Assistant (2/14-2/18/94)

Approved by: P. H. Johnson, Chief, Reactor Projects Branch 1 — 3/11/94 Date Signed

Inspection Summary:

Areas Inspected: Routine, announced inspection by resident and region-based inspectors of control room operations, licensee action on previous inspection findings, operational safety verification, surveillance program, maintenance program, licensee event reports, special inspection topics, and procedural adherence. During this inspection, Inspection Procedures 61726, 62702, 62703, 71707, 92700, 92701, 92702 and 93702 were used.

Results:

Strengths:

- The Technical Specifications Surveillance Improvement Program (TSSIP) continued to identify meaningful discrepancies in the surveillance program (Paragraphs 2.3 and 4.2).
- The licensee employed sound engineering methodology in developing an empirical method of determining the combined leak rate past RHR-V-9 and 209 (Paragraph 2.3).
- The licensee reduced power and repaired numerous steam leaks on January 14, 1994 (Paragraph 1).

- After determining that containment leakage had increased, the licensee performed a good investigation to pinpoint the leak location (Paragraph 2.4).

Weaknesses:

- The annunciator response procedure (ARP) for high pressure in the shutdown cooling suction line was inadequate, in that it did not direct operators on how to respond to the annunciator in Mode 1 (Paragraph 2.1).

- Because of the inadequate direction in the ARP, initial operator response to the high pressure condition was weak, in that operators took action without verifying the parameters of concern (e.g., they did not determine the leakrates of the boundary valves) (Paragraph 2.1).

- The licensee's initial response to high pressure in the shutdown cooling line was weak, in that relief valve RHR-V-5 was allowed to continuously cycle to reduce the high pressure condition (Paragraph 2.1).

- The licensee was not timely in determining the combined leak rate past RHR-V-9/209 (Paragraph 2.1).

- The inspection identified several weaknesses involving operator turnovers, control board walkdowns, and intrusiveness. Operators were slow in identifying apparently excessive containment boundary leakage (Paragraph 2.4) and a mispositioned valve on the main control board (Paragraph 3.2.4); operator logkeeping was weak (Paragraph 3.2.1); and operators were unaware of out-of-specification indication on the backup transformer voltage (Paragraph 3.2.4), indication of increasing unidentified leakage into the drywell (Paragraph 3.2.4), and the status or accuracy of a control room deficiency (Paragraph 3.2.4).

- The inspectors noted several examples in which the control of work appeared to be weak. These included the removal and inadequate reinstallation of instrument tubing by painters (Paragraph 2.4), the failure of chemistry personnel to notify the control room prior to operating the post accident sampling system (Paragraph 3.2.4), the performance of work which unknowingly rendered average power range monitor (APRM) A inoperable (Paragraph 5.1), and weak control of combustible materials in vital areas (Paragraph 5.2).

- Emergency core cooling system (ECCS) room coolers appeared to be degrading (Paragraph 3.3).

Summary of Inspection Findings:

- Violations 397/94-04-01 and 397/94-04-05 were opened (Paragraphs 2.1 and 5.1).

- Inspection Followup Item 397/94-04-02 was opened (Paragraph 2.2).

- Violation 397/94-04-03 was identified and closed (Paragraph 2.3).

- Non-cited violation 397/94-04-04 was noted (Paragraph 4.2).

- Violations 397/93-20-01, 397/93-18-04, 397/92-25-01, 397/92-36-02, 397/93-31-02, 397/93-31-07, and 397/93-36-01 were closed (Paragraph 7).

- Inspection Followup Items 397/94-08-01 and 397/91-24-02 were examined but not closed (Paragraphs 8.1 and 8.4).

- Inspection Followup Items 397/93-06-04 and 397/93-201-01 were closed (Paragraphs 8.2 and 8.3).

- Licensee Event Reports 397/92-20, 397/92-35 (Revisions 0 and 1), 397/93-11 (Revisions 0 and 1), and 397/93-13 (Revisions 0 and 1) were closed (Paragraph 9).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting

- Attachment 2 - February 4, 1994 Management Meeting in Region V Office

- Attachment 3 - Materials Provided by the Licensee During the February 4, 1994 Management Meeting

DETAILS

1 PLANT STATUS

At the start of the inspection period, the plant was operating at 100 percent power. Due to problems with rod position indication, the licensee decreased power to 80 percent on January 11 and 12 to perform a rod set and returned to full power. On January 14, 1994, the licensee decreased power to 50 percent in an attempt to seal a leak in the main condenser and to repair other leaks in the steam plant. Due to excessive boundary valve leakage, the attempt to repair the condenser tube leak was unsuccessful. Operators returned the reactor to full power on January 17, 1994. On February 9, 1994, reactor power coastdown began because inoperable rod position indication for control rods 46-31 and 58-23 required them to be fully inserted. On February 11, 1994, the licensee entered Final Feedwater Temperature Reduction (FFTR) and was able to return to full power. The licensee declared all fire seals inoperable on February 16, 1994, due to inadequate qualification data, and instituted continuous or hourly fire watches for each of them (see Paragraph 7.4 of this report). The plant continued to operate at full power (except for momentary downpowers to support weekly bypass valve testing and control rod exercises) until the end of the inspection period.

2 ONSITE FOLLOWUP TO EVENTS (93702, 92701)

2.1 Leakage into Shutdown Cooling Suction Line

Residual heat removal (RHR) valves RHR-V-9 and RHR-V-8 are the motor-operated suction valves for the shutdown cooling function of the RHR system. These valves function as the inside and outside containment isolation valves, respectively. RHR-V-209 is a one-inch check valve that bypasses RHR-V-9 to prevent valve locking. Additionally, these valves are high-to-low pressure interface valves that must remain essentially leak tight (leakage less than one gpm) to prevent overpressurization of the low pressure (220 psig) sections of the RHR system. The Technical Specifications (TS) that are applicable to these valves are TS 3.4.3.2, "Operational Leakage," and TS 3.6.1.2, "Primary Containment Leakage." Pressure switch PS-18, located on the low pressure piping, alerts operators to valve leakage by providing local indication and a remote alarm to the control room if pressure exceeds 168 psig. If these valves should leak moderately, relief valve RHR-V-5 prevents overpressurization of the low pressure piping by relieving at a rate of up to approximately 80 gpm, thereby reducing the possibility of an intersystem loss of coolant accident (ISLOCA) due to minor valve leakage.

On January 21, 1994, at 4:50 a.m., the annunciator for RHR SHUTDOWN COOLING PRESSURE HIGH alarmed in the control room. Control room personnel responded by accessing the alarm response procedure (ARP), PPM 4.601.A4, and by dispatching an operator to determine the pressure locally. The operator found pressure at 190 psig and relief valve RHR-V-5 lifting. At approximately 5:40 a.m., the operator reduced pressure to 50 psig and cleared the alarm by opening drain valve RHR-V-165. The operators documented the leakage of these valves in Problem Evaluation Request (PER) 294-0043. At 6:05 a.m., the RHR SHUTDOWN COOLING PRESSURE HIGH alarmed again and RHR-V-5 lifted. At 7:00 a.m., operators manually closed RHR-V-8 and declared it inoperable, and again opened drain valve RHR-V-165 to depressurize the piping. At 7:29 a.m., the

RHR SHUTDOWN COOLING PRESSURE HIGH alarmed again and RHR-V-5 lifted. Operators again manually tightened and closed RHR-V-8 and again opened drain valve RHR-V-165 to depressurize the piping.

Between 7:30 and 8:10 a.m., the resident inspectors reviewed the operating crew's response to the previous RHR shutdown cooling pressure high alarms, observed the ongoing response to the present alarm, reviewed PPM 4.601.A4, and discussed these alarms with the on-shift operating crew. From these observations, discussions, and reviews, the inspectors concluded that the operators did not promptly verify compliance with TS 3.4.3.2, "Operational Leakage." TS 3.4.3.2 requires that, with any reactor coolant system leakage greater than 1 gpm, the leakage be reduced to within limits in four hours or the plant be placed in hot shutdown within the next 24 hours. However, when the operators subsequently measured the leak rate (by manual methods) three and one-half hours after receiving the initial alarm, the leak rate was within that allowed by TS. This delay in verifying that RHR-V-8 and V-9 were not leaking in excess of 1 gpm apparently occurred because PPM 4.601.A4 did not provide adequate direction).

At 8:10 a.m., operators measured a 0.5 gpm leak rate through the isolation valves. Pressure remained at approximately 50 psig with operators periodically monitoring the pressure and leak rate. The leak rate stabilized at approximately 0.25 gpm and pressure remained at approximately 50 psig.

The inspectors' review of PPM 4.601.A4 identified that the procedure had been written for operation of the system when in the shutdown cooling mode of RHR operation (Modes 3 and 4), and did not effectively address the response to RHR shutdown cooling pressure high alarms when operating in Modes 1 and 2. Although PPM 4.601.A4 did include a NOTE that "... if RHR loops are isolated when the alarm is received, valve leak-through is a possibility" and a step to "... check RHR temperatures on RHR-TR-601 for indication of leakage from the RPV through RHR-V-8 and RHR-V-9," the procedure failed to provide the operators with adequate direction on how to respond if these valves leaked. TS 6.8.1. requires the Supply System to establish, implement, and maintain written procedures covered in Appendix A of Regulatory Guide (RG) 1.33. RG 1.33 requires procedures for abnormal, off-normal, or alarm conditions. Furthermore, the RG requires these procedures to include immediate and long-range operations actions. The failure of PPM 4.601.A4 to include sufficient immediate and long-range operations actions is a violation of TS 6.8.1 (Violation 50-397/94-04-01).

On this same morning, the inspectors discussed the leakage through RHR-V-8, V-9, and V-209 with licensee management. The discussion included the inspectors' concerns regarding the actual leakage through each of these valves, the mechanical integrity of the leaking valves, the mechanical integrity of RHR-V-5 and the repeatability of its lift setpoint, the adequacy of the PPM, and the timeliness of the operators' response. The Plant Manager stated that he would immediately evaluate the inspectors' concerns.

On January 22, 1994, at 7:56 p.m., RHR SHUTDOWN COOLING PRESSURE HIGH alarmed again, RHR-V-5 lifted and operators measured a leak rate of approximately 0.27 gpm. By 9:20 p.m., the leak rate had increased to 0.44 gpm. At 10:14 p.m., an operator manually operated the valve in the closed direction. This returned the leakage rate to approximately 0.25 gpm. An operator was

permanently stationed to monitor pressure and leakage rate. The alarm annunciated periodically until January 24, 1994, when a temporary modification was installed on the RHR-V-165 drain line to allow operators to more easily measure leakage and maintain pressure at approximately 50 psig in the drain line by throttling a small needle valve in the temporary drain line.

Over the next several days, licensee personnel performed a prompt operability determination, revised the PPM, evaluated the mechanical integrity of RHR-V-8, 9, and 209 to be satisfactory, and evaluated the mechanical integrity of RHR-RV-5 to be satisfactory. The licensee concluded that continued operation was safe and that the valves' mechanical integrity was acceptable, and that the most likely cause of increased leakage of these valves was minor cracking of the thin stellite overlay on the seating surfaces of the valves.

On February 4, 1994, the licensee performed a test which determined that the leak rate of RHR-V-9 and V-209 was approximately 0.50 gpm and that the leak rate of RHR-V-8 was approximately 0.25 gpm. The resident inspectors observed the licensee's performance of the test. This test verified that the leak rate of each of these valves was less than the TS allowed leak rate.

Subsequently, the licensee implemented a design change to return the leakage through RHR-V-8, V-9, and V-209 to the suppression pool. This design change provides the capability to throttle leakage so that pressure can be maintained at approximately 50 psig while returning leakage to the suppression pool and the operators will still receive an alarm at 168 psig, which would indicate an increasing leak rate through these valves. To determine if repair of the valves is necessary, the licensee plans to perform a leak rate test on these valves during the next refueling outage.

2.2 Inoperable Rod Position Indication

On January 10, 1994, a licensed reactor operator noted that indication for Control Rod (CR) 46-31 had become erratic when the rod position indication at step 48 indicated "XX." The position indication for CR 46-31 continued to degrade during the next two days. Initially, the licensee believed the problem was heat-related degradation of a rod position indication system (RPIS) multiplexer card. On January 12, 1994, operators fully inserted CR 46-31 and declared the RPIS for that rod inoperable. On February 8, 1994, after operators observed similar RPIS problems with CR 58-23, they also fully inserted this control rod and declared its RPIS inoperable. Additionally, several other control rods experienced RPIS anomalies, but remained operable.

Subsequent troubleshooting using time delay refractometry (TDR) and other diagnostic techniques identified low resistances to ground in conductors in a module of containment electrical penetration X101B. The electrical penetration assembly (EPA) was manufactured by a subsidiary of General Electric. By the end of this inspection period, the licensee had concluded that the EPA module had experienced moisture intrusion which was causing low conductor resistances.

To maintain reliable indication for control rods that were experiencing minor RPIS degradation due to the low resistances, the licensee implemented a temporary modification request (TMR) that changed the probe multiplexer interface card to be able to discriminate between the low resistances of the

indication circuits and the low resistances caused by the grounds. The inspectors observed the installation and testing of the TMR. The licensee also trace heated the outside portion of the EPA to prevent further degradation.

The licensee provided the resident inspectors with some of the equipment qualification records for the WNP-2 EPAs. The inspectors noted that the qualification tests for the EPA had been performed with 15 psig nitrogen as a cover gas for the seals of the EPA; however, the EPAs installed at WNP-2 were not configured with a nitrogen cover gas. The inspector observed the licensee perform a successful local leak rate test (LLRT) on the EPA of penetration X101B and viewed a stored EPA at WNP-1.

In discussions with licensee engineers, the inspectors learned that two of the four O-rings that provide an environmental barrier for each module are manufactured from ethylene propylene rubber (EPR), a material that may have a limited life when exposed to a high moisture and high temperature environment. The licensee plans to inspect containment penetration X101B during the R9 (Spring 1994) refueling outage. The inspectors will observe the licensee's inspection and conduct further followup review of the licensee's qualification records for EPAs (Inspection Followup Item (IFI) 50-397/94-04-02).

2.3 Conditions Prompting a Notice of Enforcement Discretion (NOED)

On January 10, 1994, based on findings by the licensee's Technical Specifications Surveillance Improvement Program (TSSIP), the licensee determined that a number of relays and contacts in the actuation logic for certain low pressure emergency core cooling system (ECCS) pumps and injection valves had not been previously included in time response testing required by the TS. However, the affected relays and contacts had been demonstrated to function as required during previous logic system functional tests. The TS would have required that a plant shutdown be initiated on January 12, 1994, if the relays were not tested by this time. The licensee's letter G02-94-010, dated January 13, 1994, described the identified testing deficiencies and requested that the NRC exercise enforcement discretion to permit the plant to continue operating until an emergency TS change was submitted and approved to allow operation until the next cold shutdown.

Pursuant to the licensee's request, the NRC verbally granted enforcement discretion at approximately 4:50 p.m. EST on January 11, 1994. This was confirmed by the issuance of a Notice of Enforcement Discretion letter (TAC No. M88506), dated January 14, 1994. The NRC issued Emergency Amendment No. 120 to the WNP-2 TS on January 31, 1994.

The NRC noted that the licensee's identification of the testing deficiencies reflected continuing strong performance of the TSSIP. The failure to perform the required time response testing for certain low pressure ECCS pump and injection valve relays and contacts was a violation of the requirements of TS 4.3.3.3, Table 3.3.3-3, and 4.0.3. However, because of the initiative shown by the licensee in identifying and correcting this violation, a written reply for this violation is not required (Violation 50-397/94-04-03, Closed).

2.4 Containment Leakage through Sampling Filter

On January 24, 1994, the licensee noticed that the nitrogen makeup to the drywell had been continuous for six days. The licensee documented this in PER 294-0045. The usual duration of nitrogen makeup to the drywell is one to two shifts. The potential for a containment leak was analyzed by the licensee using data for the drywell pressure decay rate, nitrogen trim line makeup rate, and drywell temperature and pressure. Nitrogen flow and drywell temperature were verified to be consistent under current operating conditions.

While data gathering and analysis were in progress, the licensee investigated potential sources of leakage. The licensee estimated the leak rate approximately seven hours after the request for a prompt operability determination. Verification of the calculation was completed four hours after the initial estimation showed the leak rate to be approximately 30 times the TS limit (the leak was quantified at approximately 5 scfm). The inspectors questioned the need for a more timely evaluation, since a potential violation of TS had existed. The leaks were subsequently found at the carbon filters in drywell radiation monitors CMS-SR-20 and 21 and were quickly repaired. These leaks were outside the boundaries of the automatic containment isolation valves, therefore this event was not reportable and had no safety significance. It was noted that drywell pressure decline coincided with a replacement of the carbon filter at CMS-SR-20, which was performed on January 16, 1994. Part of the corrective actions the licensee plans to take with respect to this issue is to enhance PPM 7.1.3 "Chemistry Weekly Iodine, Particulate, and Tritium Analysis Results," to ensure that a proper seal is established once filter changeout is completed.

Continuous operation of the nitrogen makeup system to the drywell for six days, when makeup normally requires a significantly shorter period, indicated a need for additional operator alertness to plant conditions.

2.5 Loose Instrument Tube Seismic Mounting Clamps

On January 26, 1994, the inspectors discovered several loose instrument tubing mounting clamps for the remote air intake radiation monitors. The licensee documented this in PER 294-0052. The licensee concluded that there was sufficient margin to assure operability of these monitors based upon the estimated thread engagement and generally conservative supporting arrangements for the instrument lines. Part of the immediate corrective actions the licensee performed were a visual inspection of thread engagement and an initiation of work requests to torque the clamps in accordance with PPM 10.2.10, "Fastener Torque and Tensioning." The system engineer indicated that the probable cause of the loose clamps was the work by painters who had recently painted the wall to which these clamps are attached.

Previous NRC inspection reports (50-397/92-36 and 92-43) identified weaknesses in management oversight/control of painters. If the loose mounting clamps did result from painting activity, this inspector finding would indicate a need for additional control of the work performed by painters and for a more thorough walkdown of affected areas after painting has been completed.

Two violations were identified (see Paragraphs 2.1 and 2.3).

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Plant Tours

The inspectors toured the following plant areas:

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

3.2 The inspectors observed the following items during the tours:

3.2.1 Operating Logs and Records.

The inspectors reviewed operating logs and records against Technical Specification and administrative control procedure requirements. The inspectors noted a number of discrepancies in control room operator log entries. These discrepancies included open-ended log entries (i.e., activities which were started but never completed), and items that appeared to indicate negative trends, but did not appear to have been sufficiently pursued. The inspector discussed these observations with the Operations Manager, who stated that additional management attention would be given to this area.

3.2.2 Monitoring Instrumentation.

The inspectors observed process instruments for correlation between channels and for conformance with Technical Specification requirements.

3.2.3 Shift Manning.

The inspectors observed control room and shift manning for conformance with 10 CFR 50.54 (k), Technical Specifications, and administrative procedures. The inspectors also observed the attentiveness of the operators in the execution of their duties, and the control room was observed to be free of distractions such as non-work related radios and reading materials.

3.2.4 Equipment Lineups.

The inspectors verified valves and electrical breakers to be in the position or condition required by Technical Specifications and administrative procedures for the applicable plant mode. This verification included routine control board indication reviews and conduct of partial system lineups. Technical Specification limiting conditions for operation were verified by direct observation. Observations were as follows:

Service Water Valve Mispositioned. On February 14, 1994, the licensee initiated PER 294-0097 to discuss a valve mispositioning event. The licensee determined that RHR-V-68A had been left in the closed position following surveillance testing of the service water (SW) system. Licensee investigation

revealed that the operators had left this valve mispositioned for two shifts prior to its discovery. The operators discovered this discrepancy during the performance of PPM 7.4.0.5.16, "Service Water SW-A System Test." Although this valve is operated from the control room and mimicked on the main control board, two shift turnovers and a number of operator board walkdowns did not identify the valve out of position. Because this valve receives an open signal on a SW start signal, this event had no safety significance. However, it indicated insufficient attention to detail and a need for improved shift turnovers. The inspectors discussed this PER with Operations management and the Plant Manager. Licensee management stated that control board walkdowns and turnovers needed to be more thorough and that the licensee is monitoring operator performance in this area.

Backup Offsite Power Voltage Low. On February 14, 1994, during a control board walkdown, the inspectors found that the "B" phase of the backup transformer, TR-B (a redundant off-site power source), was at 112 kilovolts (KV). The licensee's FSAR safety analysis indicates that the minimum voltage of TR-B to meet its intended safety function is 112.8 KV. The inspector informed the operators (who were unaware of the apparent low voltage condition) of this observation. The operators contacted the dispatcher, who stated that the actual voltage of TR-B was 118 KV. Therefore, the operators determined that there was a problem with the meter in the control room. The inspectors discussed this observation with Operations management, who stated that the tolerance of the voltage meters in the control room for off-site power sources is high; therefore, the operators tend to give less credence to their readings. Because two sources of off-site power are required to be operable in Mode 1, the inspectors were concerned that the operators did not have a reliable control room indication for this TS equipment. The inspectors also noted that this appeared to be an example of a long-standing problem. The inspectors discussed these concerns with the Plant Manager, who acknowledged the inspectors' comments.

Increased Unidentified Leakage in Drywell. On February 16, 1994, during a control board walkdown, the inspectors noted an increase in drywell unidentified leakage. The meter in the control room had indicated downscale for several months. However, the inspectors noted that the indication had increased over several hours from zero to approximately 0.5 gpm. The inspectors informed the shift crew (who until then had not been aware of the increase) of this observation. An equipment operator manually verified the unidentified leak rate to be approximately 0.6 gpm. Although this leak did not increase over the next several days and was well within the TS leak rate limit of a 2 gpm increase in 24 hours, the inspectors were concerned that frequent operator board walkdowns should have identified this parameter change several hours earlier. The inspectors discussed this observation with Operations management and the Plant Manager.

Control Board Deficiencies. On February 17, 1994, during a control board walkdown, the inspectors noted that the flow meter for jet pump #10 had a deficiency sticker affixed to it. The deficiency tag stated that jet pump #10 indication was erratic when the recirculation flow control valve was being operated. The inspectors questioned the accuracy of the sticker with the operators because PER 294-0110 stated that jet pump #10 had erratic indication during post-accident sampling system (PASS) sampling (one of the sample points of the PASS is from the jet pump #10 sensing line). Operations had determined

the previous day that the erratic indication had resulted because Chemistry personnel were taking a PASS sample, without first informing the operators. However, the on-shift crew stated that they were unaware of the accuracy or the status of this control board deficiency because they had just came back from being off-shift.

The operators contacted the work control center. The work control shift manager stated that the control room deficiency associated with jet pump #10 was not accurate and had actually been canceled. The operators then removed the deficiency tag and discarded it at the direction of work control. The inspectors discussed this observation with the Operations Manager. The Operations Manager stated that it was his expectation that each member of the shift crews walk down the control boards thoroughly during shift turnover to ascertain the status of indications, annunciators, and deficiencies. In addition, the Operations Manager stated that it was his expectation that chemistry personnel inform the control room before operating the PASS. The inspectors discussed this event with the Plant Manager, who acknowledged the inspectors' comments.

3.2.5 Equipment Tagging.

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

3.2.6 General Plant Equipment Conditions.

The inspectors observed plant equipment for indications of system leakage, improper lubrication, or other conditions that would prevent the system from fulfilling its functional requirements. Annunciators were observed to ascertain their status and operability.

3.2.7 Fire Protection.

The inspectors observed fire fighting equipment and controls for conformance with administrative procedures. A weakness with the control of combustible material in vital areas is discussed in Paragraph 5.3 of this report.

On January 11, 1994, while touring the battery and cable spreading rooms, the inspectors discovered multiple examples of cable pull strings in cable trays/raceways, conduit, and terminal boxes. These pull strings had been left in place from the initial installation of electrical cables to allow for future pulling of cable. The inspectors questioned whether this was a possible violation of electrical separation criteria and/or the fire protection program. The licensee documented the concern in PER 294-0024 and subsequently performed an operability assessment. The licensee determined that the pull strings, which are made of polypropylene or Nylon-6 type material, are nonconductive and have properties similar to the installed cable jacket material. In addition, the pull string material has a negligible effect on the ignition temperature and very little mass when compared to the installed cable jackets.

The licensee could not identify any credible failure mechanism that would keep the electrical raceway system from meeting any single failure criteria, or

would contribute to or create any common mode failure with the pull strings left in place. The raceway fill issue was determined not to be a problem because of the raceway geometry and the small area occupied by the pull string. The combustibility issue applies to conduit, cable tray, and electrical enclosures. As indicated in the response to Question 3.63 in Generic Letter 86-10, cables in metal conduits are not considered as intervening combustibles. Thus, the pull strings in conduits do not present a combustibility concern. Considering pull strings as nonsafety-related (non-1E), low energy cables, they meet the same physical and electrical separation requirements as scheduled non-1E cables.

To ensure that future installation of cable pull strings will be bounded by the justification provided in the plant specifications for the existing polypropylene or Nylon-6 type material, the licensee will revise PPM 10.25.54, "Cable Pulling Instruction and Inspection," to specify pull string material. The inspectors considered this issue to have been sufficiently evaluated by the licensee and consider this item closed.

3.2.8 Plant Chemistry.

The inspectors reviewed chemical analyses and trend results for conformance with Technical Specifications and administrative control procedures. The licensee continued to operate with elevated reactor water conductivity. The licensee attempted to seal a suspected condenser tube leak on January 14, 1994, but was unsuccessful due to excessive boundary valve leakage. The licensee controlled reactor conductivity at less than 0.17 microSiemens by frequent condensate filter demineralizer changeouts.

3.2.9 Radiation Protection Controls.

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

3.2.10 Plant Housekeeping.

The inspectors observed plant conditions and material/equipment storage to determine the general state of cleanliness and housekeeping. Housekeeping in the radiologically controlled area was evaluated with respect to controlling the spread of surface and airborne contamination.

3.2.11 Security.

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

3.3 Engineered Safety Features Walkdown

The inspectors walked down selected engineered safety features (and systems important to safety) to confirm that the systems were aligned in accordance with plant procedures. During the walkdown of the systems, items such as hangers, supports, electrical power supplies, cabinets, and cables were inspected to determine that they were operable and in a condition to perform their required functions. Proper lubrication and cooling of major components were also observed for adequacy. The inspectors also verified that certain system valves were in the required position by both local and remote position indication, as applicable.

The inspectors walked down accessible portions of the following systems on the indicated dates:

System	Dates
Diesel Generator Systems, Divisions 1, 2, and 3.	January 19, February 9
Hydrogen Recombiners	February 9
Low Pressure Coolant Injection (LPCI) Trains "A", "B", and "C"	January 10, February 2
Low Pressure Core Spray (LPCS)	January 10, February 2
High Pressure Core Spray (HPCS)	January 10, February 2
Reactor Core Isolation Cooling (RCIC)	January 10, February 2
Residual Heat Removal (RHR), Trains "A" and "B"	January 10, February 2
Scram Discharge Volume	February 9, 14
Standby Gas Treatment (SGT)	February 9, 14
Standby Liquid Control (SLC)	February 9, 14
Standby Service Water	February 14
125V DC Electrical Distribution, Divisions 1 and 2	January 25, February 9
250V DC Electrical Distribution	January 25, February 9

Air Handling Unit Degradation. On February 2, 1994, during a walkdown of the ECCS listed above, the inspectors performed a detailed inspection of the ECCS room coolers. Each of these room coolers has an air handling unit that is cooled by the service water system. The inspectors noted that each of the room coolers had some degradation due to foreign material blocking the air intake structure of the cooling unit. The most significantly degraded of

these was the RCIC room cooler. The inspectors noted that RCIC room cooler had foreign material covering about 20 percent of the available surface area.

The inspectors notified the system and design engineers. The licensee stated that this amount of degradation would not affect system operability because there was a significant amount of margin built into the design. The licensee stated that the room coolers were able to perform their intended safety function with only 65 percent efficiency on the water side and that past cleaning of the air side had had little effect on the efficiency of the room cooler. In addition, the licensee stated that the room coolers had a preventive maintenance task to clean the air side of the room coolers with a water lance every three years.

The inspectors discussed these observations with the Maintenance Manager. The inspectors noted that the design basis of the ECCS included the ability to operate for 100 days post-accident without access to the reactor building. Additional degradation of the room coolers should be expected along with the as-found condition after an accident. The Maintenance Manager agreed that it would be prudent to not allow significant amounts of foreign material to accumulate on the air side of the ECCS room coolers given this information. The Maintenance Manager also stated that, although the Supply System may not increase the frequency of the full PM task of cleaning the room coolers with a water lance, they would consider more frequent on-line cleaning with a brush or other device to remove the bulk of the foreign material.

No violations or deviations were identified.

4 SURVEILLANCE TESTING (61726)

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

The inspectors observed portions of the following surveillance on the dates shown:

Procedure	Description	Dates Performed
7.4.6.1.1.1	Local Leak Rate Test (LLRT) of Penetration X101B	February 4
7.4.6.1.8.2	LLRT of CSP-V-3/4	February 4
7.4.3.7.5.9	Containment H_2-O_2 Monitors Channel Functional Test	February 8
8.3.320	HPCS Level 8 Isolation Channel Functional Test	February 18
8.3.126	Special Test of DG-1 Air Start Capacity	February 18

4.1 LLRT of Penetration X101B

On February 4, 1994, the inspectors witnessed the LLRT of penetration X101B per PPM 7.4.6.1.1.1. The surveillance was performed satisfactorily and in accordance with procedural direction. However, the craftsman noted that Step 19 of the procedure required the performer to depressurize the penetration to 25 psig, quickly remove the test equipment, and restore the penetration to leave a nitrogen blanket on the penetration. The craftsman noted that the depressurization and capping of the line would not be effective in leaving a nitrogen blanket on the penetration because of the very small volume of the penetration. After performing this step as written, the penetration instantly depressurized as the craftsman predicted. The craftsman also indicated that he had expressed the concern that Step 19 would not work to the system engineer and to his supervision in the past, but the procedure was never revised. The inspectors discussed this observation with the system engineer. The system engineer initiated a procedure deviation to correct the apparent procedural inadequacy.

The inspectors discussed issues associated with the LLRT with the Plant Manager. The Plant Manager agreed with the inspectors' conclusions and acknowledged that revising procedures based on the input of the craft demonstrates a commitment to procedure adherence.

4.2 HPCS LEVEL 8 Isolation Special Test

On February 18, 1994, the inspectors witnessed the performance of a special surveillance test associated with actuation of the HPCS isolation circuitry. The surveillance was performed in a deliberate and formal manner with management oversight present. The licensee performed this test because personnel associated with the Technical Specification Surveillance Improvement Program (TSSIP) had determined that several of the relays and contacts in this actuation logic had not been surveillance tested as required periodically by TS 4.3.3.2. Therefore, the licensee's TSSIP review determined that the licensee was in violation of the TS. After the 24 hours allowed by TS 4.0.3, the licensee declared the HPCS inoperable. The licensee reported this condition to the NRC in accordance with the requirements of 10 CFR 50.72. The licensee expeditiously wrote and performed surveillance test procedure PPM 8.3.320 to restore compliance with the TS and operability of HPCS. The licensee intends to describe this event in a licensee event report. The licensee's previous failure to perform this surveillance testing as required is a violation of the requirements of TS 4.0.3. However, because the criteria of Section VII.B(2) of the enforcement policy were satisfied, this violation was not cited (Non-Cited Violation 94-04-04, Closed).

One non-cited violation was identified (Paragraph 4.2).

5 PLANT MAINTENANCE (62703)

During the inspection period, the inspectors observed and reviewed documentation associated with maintenance and problem investigation activities to verify compliance with regulatory requirements and with administrative and maintenance procedures, required QA/QC involvement, proper use of clearance tags, proper equipment alignment and use of jumpers, personnel qualifications,

and proper retesting. The inspectors verified that reportability for these maintenance activities was correct.

The inspectors witnessed portions of the following maintenance activities:

Description	Dates Performed
FM1204, Evacuate/Restore Penetration X101B	February 4
CY7501, Replace Fire Damper WMA-FD-31	February 8
FJ8501, Troubleshoot and Repair Average Power Range Monitor (APRM) A	February 10
FW9501, Replace Cell 38 on B1-1	February 11
FR1704, Install Leakoff Jumper at RHR-V-6A	February 15-16
DH3901, Replace Fire Damper ROA-FD-7	February 18

5.1 APRM A Troubleshooting

On February 10, 1994, the licensee performed troubleshooting activities for APRM A. The licensee had determined that the input to the plant computer from APRM A for determining the gain adjustment factor was faulty. This function of the APRM was not considered safety related because it did not involve any alarm or trip functions. The task was performed well and in accordance with licensee procedures. However, the inspectors noted that the work on the computer inputs impacted upon the APRM's safety-related functions.

While the job was in progress, the inspectors reviewed the instrumentation diagram for APRM A with the system engineer (SE). The SE explained that the troubleshooting activities were taking place on the auxiliary card, which provided for various nonsafety-related features such as panel indication and inputs to the plant computer. This card was removed from the drawer and restored intermittently during the course of the work. In reviewing the print, the inspectors noted that the auxiliary card also serves as an intermediate node between the APRM averaging circuit and the card that provides the safety-related reactor trips (i.e., reactor scram and rod block) and alarms. Therefore, the removal of the auxiliary card of APRM A rendered the instrument incapable of providing the required trips and alarms and, therefore, inoperable.

The inspectors reviewed the Limiting Conditions for Operation (LCO) log book and the control room operator's log, and noted that the operators had not made entries in these logs to track the inoperability of APRM A. The inspectors discussed this observation with the Shift Technical Advisor (STA) and the Shift Manager. The Operations personnel appeared to be unaware that the work on APRM A would have an impact on the instrument's safety-related functions. After the inspectors showed the operators the APRM A process diagram, the operators declared APRM A inoperable. Further discussion with the SE revealed that troubleshooting activities on APRM A had been initiated the previous day. Operators did not log APRM A as inoperable on this occasion either. The Shift Manager initiated a PER to document the problem and initiate corrective

actions. In addition, the licensee performed the weekly surveillance on APRM A, once the work was complete, to restore operability.

This event had minor safety significance in that the APRM provides a half-scram to the reactor protection system for several events for which the licensee takes credit for in the FSAR Chapter 15 safety analysis. However, only two of three APRM channels per division are required to be operable while operating in Mode 1. The licensee performed a review and determined that no other APRM channel was inoperable during the work on APRM A.

PPM 1.3.1D, Revision 2, "Conduct of Operations; Administrative Requirements," Paragraph 4.8.4, states:

> The Shift Manager or Control Room Supervisor will initiate a Technical Specification [TS] Inoperable Equipment/LCO/ODCM Status sheet similar to Attachment 5.8 whenever any of the following conditions exist:
>
> a. A system or component required by Technical Specifications as a limiting condition for operation in the present plant mode becomes inoperable (LCO) or;
>
> b. A redundant system or component required by the Technical Specifications in the present mode becomes inoperable (Inoperable Equipment).

On February 9 and 10, 1994, a TS Inoperable/LCO/ODCM Status sheet was not implemented to track the status of the inoperable equipment because the senior licensed operators did not have a sufficient understanding of the effect of the work on APRM A (i.e., that APRM A was inoperable due to the work). The failure to declare APRM A inoperable and make entries into the TS Inoperable/LCO status log during troubleshooting activities was a violation of PPM 1.3.1D and 10 CFR 50, Appendix B, Criterion V (Violation 50-397/94-04-05).

The inspectors concluded that weaknesses existed in the Operations Division's handling of the APRM A troubleshooting. The work control center's review of the work order did not identify that the removal of the auxiliary card would interrupt the safety-related functions of the instrument, so that the operating crew could have been alerted. In addition, the operating crew that approved the work did not recognize the effects of the troubleshooting activities that occurred during their shift. The inspectors discussed these observations with the Plant Manager, who acknowledged the inspectors' comments.

5.2 Battery Cell Replacements

On February 11, 1994, the inspectors witnessed the replacement of cells 37 and 38 on safety-related Battery B1-1. These cells were replaced per an emergency work order with the plant in a two-hour TS Action Statement. The task was completed in a formal and expeditious manner with no problems noted. However, the inspectors noted that a total of six cells had been replaced on B1-1 during this inspection period. The inspectors also noted that the battery did not appear to be in good condition, with a number of cells displaying a significant amount of sedimentation, cracks, or degrading voltage trends. The inspectors discussed these observations with the licensee. The licensee

stated that, although both safety-related 125V batteries (B1-1 and B1-2) are operable, they are aware of their poor condition and intend to replace them during the 1994 refueling outage.

5.3 Fire Damper Replacements

On February 8, 1994, the inspectors witnessed the replacement of fire damper WMA-FD-31. This fire damper isolates ventilation between the Division 1 battery and battery charger rooms. This work required the erection of scaffolding in both rooms. Due to working in areas near energized circuits, licensee procedures require non-conductive or wooden supports for the scaffolds. The inspectors noted that the licensee erected wooden scaffolds in the battery and battery charger rooms. PPM 1.3.10, "Fire Protection Program," requires that a transient combustible permit be obtained for any wood used in vital areas. The licensee obtained a permit for the wood; however, the inspectors noted that the block on the permit labeled "Specific Location of the Combustibles," contained an entry for Battery Room #1, but did not include the battery charger room. The inspectors notified the Shift Support Supervisor (SSS) of this condition. The SSS was unaware that wood was being employed in the battery charger room, but stated that it was acceptable to use one permit for a whole job as long as each specific location was annotated on the permit. The SSS reissued the transient combustible permit for the fire damper replacement with both locations annotated on the permit.

Although this item appeared to be minor, the inspectors concluded that it indicated that the control of work and attention to detail could be improved. Communications between Operations personnel and the craftsmen appeared weak, contributing to the SSS initially issuing the transient combustible permit improperly. The inspectors discussed this issue with the Plant Manager, who acknowledged the inspectors' comments.

One violation was identified (Paragraph 5.1).

6 RELIABILITY-CENTERED MAINTENANCE (RCM) (62702)

On January 3, 1994, the inspectors assessed the licensee's RCM program. RCM is a program in which traditional preventive maintenance (PM) practices of performing PM tasks on a periodic basis are replaced with PM tasks which are scheduled based on monitoring of equipment performance. The inspectors concluded that the licensee was developing a satisfactory and highly technical program to meet the new maintenance rule.

6.1 RCM Scheduling

In 1990, the licensee initially commenced the establishment of an RCM program. The licensee hired a contractor to provide a computer work station and a full RCM program for 132 systems within a 30-month period. Due to apparently weak licensee oversight, the RCM analysis had not been completed for any system and a computer work station was not available when the 30-month contract period ended. The licensee terminated this contract.

In late 1992, the licensee hired a new contractor to aid the licensee's staff in setting up an RCM program. The licensee and their contractor performed complete analyses for two model systems [RHR and circulating water (CW)] to

provide a good baseline for the analyses of 132 systems. The licensee and contractor took eight months for the analysis of RHR and CW. In addition, a third system (LPCS) was completed during this inspection period (for a total of 3 completed). The licensee has scheduled the remainder of the full RCM program analysis and computer work station to be completed in a 20-month period. This 20 months assumes five full-time people working on the project, although only three of these five positions had been filled as of the end of this inspection period. The inspectors discussed these observations with the Plant Manager, who stated that close management attention will be paid to the RCM project to ensure that the goals are met.

6.2 RCM Technical Analysis

The inspectors also assessed the technical capabilities of the RCM group. Condition monitoring was already being performed for a number of components at WNP-2. The licensee performs vibration analysis, lube oil analysis, thermography, and motor current signature analysis of various components to assess the health of those components. The licensee appeared to have a good training program to ensure that craft personnel are proficient in using the sophisticated equipment. The inspectors will continue to monitor the licensee's progress in using condition monitoring to predict the need for preventive maintenance.

No violations or deviations were identified.

7 FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS (92702)

The inspectors reviewed records, interviewed personnel, and inspected plant conditions relative to licensee actions in response to previous violations:

7.1 (Closed) Violation 50-397/93-20-01): Inadequate Corrective Action for Drywell-to-Suppression Chamber Bypass

This item involved an apparent violation of regulatory requirements to implement effective corrective actions in response to a previous NRC-identified violation. In particular, the licensee's review of operating procedures to ensure that TS limits for drywell-to-suppression chamber bypass leakage was incomplete, because it excluded the review of surveillance procedures. The inspectors reviewed the licensee's root cause evaluation and proposed corrective actions, concluded that the corrective actions were appropriate, and verified their completion. The licensee's corrective actions included the following:

- review of applicable maintenance and surveillance procedures to ensure that the drywell-to-suppression chamber bypass leakage limits are not challenged

- revision of procedures, as necessary, to ensure that containment isolation valves remain closed during testing or to require that the testing only be performed during modes 4 or 5

- revision of the Scheduled Maintenance System (SMS) to provide a consistent method for designating plant conditions for procedure performance

7.2 (Closed) Violation 50-397/93-18-04: Improper Posting for Propped Open Fire Door

This apparent violation involved an incident wherein an NRC resident inspector found a fire door propped open without the required impairment checklist (permit) being posted. The licensee's root cause evaluation determined that the maintenance personnel who propped open the door had verified that permits had been posted for the fire door but did not check the nature of the permits. Furthermore, PPM 1.3.10, "Fire Protection Program Implementation," requirements for posting the permit on the affected door were not clearly specified in the procedure.

The inspectors verified that licensee management discussed the relevant sections of PPM 1.3.10 with maintenance personnel and that corrective actions to revise PPM 1.3.10 to clearly require postings for each planned and unplanned system impairment were accomplished.

7.3 (Closed) Violation 50-397/92-25-01: Failure to Follow Procedures

This apparent violation involved failure to follow procedures. In the first example, licensee personnel did not properly record test data on some 250 VDC batteries. The second example involved the licensee's failure to provide a signature blank to verify compliance with test procedure prerequisites for RCIC operability tests.

Regarding the first example, the inspectors verified that the licensee had recorded the battery data as required by the procedure and had evaluated the data to have satisfied the acceptance criteria. However, the inspectors agreed with the licensee's assessment that the records had been poorly kept in that they had been entered on the wrong data sheet and filed separately from the maintenance work request (MWR) package. The inspectors were aware that licensee personnel involved with testing of the replacement battery had been informed of their poor work practices and that the importance of procedural compliance was being emphasized company wide by Supply System management.

Pertaining to the second example, the inspectors reviewed the licensee's proposed corrective actions. The inspectors considered the corrective actions appropriate to the circumstances involved in the violation. According to the licensee, all three of the proposed corrective actions were completed by the time of the inspection. The corrective actions involved:

- Changing PPM 1.2.3, "Use of Controlled Plant Procedures," to more clearly define management's expectations that performance of all prerequisites is mandatory.

- Deleting the prerequisite signature requirement from PPM 1.5.1, "Technical Surveillance Testing Program." (This appeared justified based on the above action.)

- Reviewing PERs since 1989 to look for any trends which might indicate that procedure writers were failing to follow PPM 1.5.1. (The licensee did not find any trend to indicate that procedure writers were failing to follow procedures.)

The inspectors checked the latest revisions of PPM's 1.2.3 and 1.5.1 and verified that the licensee had accomplished its proposed corrective actions.

7.4 (Closed) Violation 50-397/92-36-02: Failure to Control Radiological Controlled Area Barrier as Required by Procedures

This was a repeat violation of radiologically controlled area barrier maintenance requirements. The licensee responded to the Notice of Violation (NOV) by letter No. G02-93-017, dated January 20, 1993.

The licensee's response committed to several corrective actions to preclude recurrence. The inspectors discussed the actions taken with responsible licensee personnel and examined objective evidence of completion of the more substantial corrective actions. The inspectors concluded that the licensee had acceptably performed all the committed corrective actions. In addition, discussions with licensee employees determined that the frequency of radiologically controlled area barrier problems had been much reduced, and provided evidence that the completed corrective actions had been effective.

In preparation for the 1994 refueling outage, the licensee was heavily engaged in training of contractor lead personnel regarding the requirements for maintenance of radiologically controlled area barriers.

7.5 (Closed) Violation 50-397/93-31-02: Failure to Initiate a Problem Evaluation Request for an Incorrectly Oriented Main Steam Isolation Valve

This violation involved a situation wherein licensee personnel observed that a solenoid valve was misoriented causing air "blow-by" through the closed valve, but failed to write a PER documenting the misorientation. The licensee responded to the NOV by letter No. G02-93-265, dated November 8, 1993.

The licensee committed to several corrective actions in their response. The inspectors determined, through discussions with Supply System personnel and by examination of objective evidence demonstrating completion of the corrective action, that the licensee had acceptably completed the specified actions.

7.6 (Closed) Violation 50-397/93-31-07: Instrumentation and Control Technicians Did Not Follow a HPCS Surveillance Procedure

This violation involved the I&C technicians' failure to follow the procedure for performing Surveillance Test Procedure "HPCS System Transfer on CST Low Level." The licensee responded to the violation by letter number G02-93-265, dated November 8, 1993.

In the licensee's response, certain corrective actions were committed. The inspectors examined objective evidence of completion of all committed corrective actions and found these acceptable.

7.7 (Closed) Violation 50-397/93-36-01: Failure to Submit a License Amendment Request as Required by 10 CFR 50.59 and 50.90

This violation involved a situation wherein the licensee changed eight valves from motor-operated to manually-operated, which involved a change to TS, without first submitting the required request for TS amendment to the NRC.

The licensee performed a root cause analysis and determined that several corrective actions were required to correct the individual violation and preclude recurrence. The inspectors examined objective evidence of completion of the committed corrective actions. Based upon these examinations, the inspector concluded that the licensee had acceptably completed the committed corrective actions.

8 FOLLOWUP (92701)

8.1 (Open) Followup Item (50-397/94-08-01): Foam Sealant Fire Seal Adequacy

The licensee has been evaluating the adequacy of foam sealant (BISCO SF-20) penetration fire seals based on concerns raised in September 1993 as to the adequacy of past inspections of these seals. During this inspection period, the licensee conducted random inspections of fire seals that had a greater probability of having defects. The licensee considered some of these fire seals to be impaired after finding that they had defects.

On February 15, 1994, the licensee notified the NRC in a 10 CFR50.72 report that all foam-sealed fire penetrations had been declared inoperable. The licensee declared the penetrations inoperable because certain fire penetration seal designs had not been adequately qualified and quality records of installed penetration seals had created doubt as to the accuracy of the records. The licensee documented this deficiency in PER 294-0101.

To status the safety significance of the licensee's inspections during this period, the inspectors met weekly with licensee managers who are supervising the reinspection effort. Additionally, the inspectors observed some of the fire seals that had been impaired. Licensee actions associated with the reinspection activities appeared conservative. Inspector followup of this activity will continue until the licensee completes the reinspection effort and overall safety significance is assessed.

8.2 (Closed) Unresolved Item 50-397/93-06-04: Incorrect Statement in Licensee's Response to Notice of Violation 93-07-01

This issue involved an incorrect statement in the licensee's response to the NRC regarding a Notice of Violation. The licensee's response, dated April 23, 1993, indicated that the discrepancies were found as a result of management housekeeping tours when, in fact, the discrepancies were identified by the NRC inspector. The unresolved item was for the NRC to determine whether this incorrect statement violated NRC requirements.

The licensee issued a letter to the NRC, dated May 13, 1993, to revise and correct their original response and to recognize that the NRC inspector had found the discrepancies. The licensee determined that the incorrect statement was caused by the unclear wording of the PER, which could have been misconstrued to indicate that plant personnel had observed the discrepancies. The licensee had not verified the source of the PER during the root cause evaluation, leading to the incorrect statement.

The inspectors concluded that, while the statement was incorrect, there was no intent to misstate the facts and the misstatement was not substantive in dealing with the discrepant issues.

8.3 (Closed) Followup Item 50-397/93-201-01: Inadequate Evaluation of Spray Pond Chemistry

This issue involved a situation wherein the spray pond sulfur content (as high as 183 ppm) exceeded the 150 ppm control limit imposed by PPM 1.13.1. In addition, the licensee failed to document the out-of-specification condition using their PER program. The licensee responded to the NRC inspection findings by letter No. G-02-93-126, dated May 27, 1993. The licensee committed to certain corrective actions, to preclude recurrence, in this response.

The inspectors examined the licensee's objective evidence of completion for each corrective action. The licensee's evaluation concluded that the 150 ppm sulfur limit was based upon the consideration that the stress corrosion tube cracking potential be minimized, not totally eliminated, by the application of these limits and that heat exchanger tubes would be emphasized for enhanced monitoring. Out-of-specification conditions would be referred to engineering for evaluation. The licensee also reemphasized the expectations for documenting out-of-specification conditions, using the PER program, to all employees. The inspectors considered the licensee's actions adequate to resolve the issue.

8.4 (Open) Followup Item 50-397/91-24-02, Diesel Generator (DG) Air Start Receiver Volume

NRC Inspection Report 50-397/91-24 noted that the licensee did not have calculations or test data to support a statement in the Final Safety Analysis Report (FSAR) that the starting air systems for the Division 1 and 2 DGs could provide a minimum of seven starts and that the starting air system for the high pressure core spray (HPCS) DG could provide three starts (FSAR Section 9.5.6). The licensee had previously identified this issue and was pursuing its resolution.

NRC Inspection Report 50-397/92-22 noted that the licensee had discovered startup test data and had performed a calculation which supported the statement in the FSAR. The report noted the following outstanding issues regarding the HPCS DG:

- The alarm for low starting air receiver pressure was set below the pressure required to provide three starts, and

- During a start, the HPCS DG appeared to consume twice as much air per air motor as was stated in the vendor information and as was used during the Division 1 and 2 DG startup tests.

The first issue was identified by the licensee and was addressed in PER 292-445. The second issue was identified by an NRC inspector.

PER 292-445: The control room alarm for low HPCS DG air receiver pressure was set at 208 psig, which was 9 psig below the minimum pressure required to provide three starts as committed by the FSAR. A design change was needed to replace the pressure switch with one that had a smaller deadband. The licensee expected that the design change would be implemented by the 1994 refueling outage. In the interim, equipment operators continue to verify on

their daily rounds that HPCS DG starting air receiver pressure is greater than 217 psig. This appeared to be an acceptable interim resolution.

PER 293-354: In March 1993, the design engineer requested that operators record the Division 1 DG air start receiver pressure before and after the monthly test run. With this data, the engineer determined that although the air consumed per DG start was greater than had been previously calculated and had been determined during startup testing, the air start system could reliably provide five starts. The engineer initiated PER 293-354 on April 5, 1993, to address the higher air consumption rate.

In response to this PER, Engineering determined that the Division 1 and 2 DGs were operable based their ability to start five times, consistent with the statement in the original Safety Evaluation Report (SER) that starting air system capacity for five starts was acceptable. To resolve PER 293-354, the licensee planned to perform a special test to determine the air consumption of the DG 1 and 2 starting air systems and compare results to vendor data. The testing has been planned for the next outage of sufficient duration, which is scheduled for spring 1994.

PER 293-458: In April 1993, the licensee determined that although the HPCS DG starting air system could provide three successful starts, it could not provide one successful start following an unsuccessful start attempt. The starting air system is engaged for approximately two seconds during a successful HPCS DG start and approximately five seconds during an unsuccessful start attempt. While there did not appear to be a regulatory basis for the starting air system's being sized to provide one successful start after an unsuccessful start, this feature would increase DG reliability. The licensee had not yet determined corrective actions.

During this inspection period, because the design basis of the DG air start system had not ben verified during pre-operational testing, the licensee performed a test on DG 1 to verify its air starting capacity. The licensee performed the test with both air banks and all air start motors in service, which represents the current configuration of the air start system. Seventeen cold starts of the diesels were achieved, which is greater than the seven starts committed to in the FSAR and the five required by the SER. The resident inspector observed the performance of the test and concluded the test was well controlled. The test verified the design basis of DG 1 and 2 air start systems.

This item remains open pending the licensee's resolution and the inspectors review of PER 292-445 and PER 293-458.

No violations or deviations were identified.

9 ONSITE REVIEW OF LICENSEE EVENT REPORTS (LERs) (92700)

The inspectors reviewed the following LERs associated with operating events. Based on the information provided in the report it was concluded that reporting requirements had been met, root causes had been identified, and corrective actions were appropriate. The below LERs were reviewed during this inspection period.

9.1 (Closed) LER 50-397/92-20: Flow Element for Low Pressure Core Spray (LPCS) Minimum Flow Element not Properly Installed

This LER identified that repetitive problems occurred with the LPCS system minimum flow control elements, which challenged system operability, between December 1991 and April 1992. The licensee performed a root cause evaluation and determined that the flow element (LPCS-FE-002) had been improperly installed during plant construction due to poor work practices. The installation allowed air to be entrained in the sensing lines during pump operation, given erroneously high readings which could have resulted in premature closing and failure to open of the minimum flow valve.

The licensee issued a temporary procedure change to the LPCS System Operability Test procedure (Procedure PPM 7.4.5.1.7) to vent and equalize the instrument if the indicator did not indicate about 0 gpm, until the sensing lines could be fixed. A Plant Modification was completed to modify the sensing line taps on the instrument to preclude trapping air in the instrument lines. The licensee alerted all system engineers and I&C technicians to be mindful of improper orientation of flow element sensing line taps and improper sloping of lines on other instruments. System engineers also performed system walkdowns to determine any other instances of improper flow element installations; none were found. In addition, the WNP-2 Plant Manager issued a memorandum to all employees to assure that they were aware of management's expectations regarding the documentation of all problems using the PER process. Based on the licensee's actions, this LER is closed.

9.2 (Closed) LER 50-397/92-35, Revisions 0 and 1: Inadequate Testing of the Scram Discharge Volume Vent and Drain Valves

This LER documented the situation wherein test instructions were not sufficient to demonstrate the operability of scram discharge volume vent and drain valves during stroke time testing following modification, and procedures used to satisfy TS stroke time requirements were inadequate.

The licensee's root cause assessment for these conditions determined that operability requirements had been incorrectly incorporated into modification test instructions and that surveillance test procedure development had been technically inadequate. The licensee determined that several corrective actions were needed to resolve the issues and preclude recurrence.

The inspectors examined objective evidence of completion of the committed corrective actions and determined that these appeared to have been adequate and completed. The inspectors observed, however, that some of the corrective actions had been completed later than committed, one action by up to 1.5 months later. The licensee has recognized this situation and has taken actions to better manage their corrective action backlog. The inspectors had no further questions. This LER is closed.

9.3 (Closed) LER 50-397/93-11, Revisions 0 and 1: Surveillance Requirements for Refueling Platform Inadequately Implemented Due to Analysis Deficiencies and Surveillance Requirement Misinterpretation

This LER documented that past surveillance testing had not been fully adequate to demonstrate operability of hoists associated with the refueling platform.

Specifically, testing of certain load-related interlocks and cutoffs did not assure they would operate within TS limits (e.g., overload cutoff, hoist loaded interlock, slack cable cutoff for main hoist, and overload cutoff and loaded interlocks for the frame mounted and monorail hoists).

The licensee's root cause evaluation concluded that: (1) a personnel error resulted in the misinterpretation of testing requirements for the slack cable cutoff; (2) there was inadequate consideration of instrument loop uncertainties during setpoints and tests weight determination; and (3) there was inadequate verification during initial procedure preparation to ensure satisfaction of TS requirements.

The inspectors reviewed the licensee's corrective actions for this event, as documented in NRC Inspection Report 50-397/93-31. The inspectors concluded that the licensee did not appear to have a documented analysis to support their assertion that the incorrect setpoints were not of sufficient magnitude to appreciably affect the likelihood of damage to reactor vessel internal components, full bundles, or refueling platform hoists. During this inspection period, the inspectors again examined the licensee's documentation supporting the assertions, and found these acceptable to address the previous questions. In addition, the licensee had submitted a TS amendment request to NRR addressing and clarifying the TS limits. Based on the licensee's actions, this LER is closed.

9.4 <u>(Closed) LER 50-397/93-13, Revisions 0 and 1: Loss of Containment Integrity Due to a Reactor Core Insolation Cooling (RCIC) System Single Failure Criteria Violation Due to Original Design Errors and Procedures Deficiencies</u>

This LER documented that design errors were identified by licensee engineers working in the Component Safety Classification and Design Requirement Document Programs. The root cause of the deficiency was errors in the original plant design. The specific deficiency involved the containment isolation design for the RCIC pump suction line not meeting single failure design criteria, in that failure of Division 1 DC power to the RCIC system would cause the motor operators for the pump suction isolation valve and the auxiliary cooling water supply valve to fail as-is in the open position.

The licensee took several immediate corrective actions, and obtained an emergency amendment from the NRC on April 9, 1993, to temporarily restore RCIC system operability until the next refueling outage. In addition, during the 1993 refueling outage, the licensee installed a Quality Class I motor-operated isolation valve in the cooling water line to the RCIC turbine auxiliaries to mitigate the fail-as-is position of the valves described above. The function of the isolation valve is to close and isolate the RCIC turbine auxiliaries in the event that the RCIC pump suction and auxiliary cooling water supply valves cannot be closed.

The inspectors reviewed the design modification with the design engineer and concluded that the original design error had been corrected. This LER is closed.

No violations or deviations were identified.

ATTACHMENT 1

1 PERSONS CONTACTED

*V. Parrish, Assistant Managing Director for Operations
*M. Flasch, Engineering Director
*J. Gearhart, Quality Assurance Director
*J. Swailes, Plant Manager
*G. Smith, Operations Division Manager
*R. Webring, Technical Services Manager
M. Monopoli, Maintenance Division Manager
*J. Sampson, Maintenance Production Manager
*P. Bemis, Regulatory Programs Manager
*W. Barley, Radiation Protection Manager
*H. Kook, Licensing Manager
*D. Larkin, Engineering Services Manager
*S. Kirkendall, Plant Support Engineering Manager
*J. Benjamin, Quality Assessments Manager
*R. Barbee, System Engineering Manager
*J. Peters, Administrative Manager
*W. Shaeffer, Operations Manager
*M. Mann, Assistant Operations Manager
*J. Muth, Plant Assessments Manager
*P. Harness, Mechanical Design Manager
*B. Hugo, Licensing Engineer
*D. Schumann, Principal Engineer
*D. Williams, Bonneville Power Administration

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

*Attended the Exit Meeting on February 25, 1994.

2 EXIT MEETING

An exit meeting was conducted on February 25, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspectors' findings. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

FEBRUARY 4, 1994, MANAGEMENT MEETING IN THE REGION V OFFICE

On February 4, 1994, members of Supply System management met with Region V managers in the Region V Office. The following persons were in attendance:

Supply System

J. C. Gearhart, Director, Quality Assurance
G. O. Smith, Operations Division Manager

NRC Region V

S. A. Richards, Acting Director, Division of Reactor Safety and Projects
P. H. Johnson, Chief, Reactor Projects Branch 1
F. R. Huey, Enforcement Officer
D. F. Kirsch, Technical Assistant

Mr. Richards opened the meeting at 9:30 a.m. by welcoming Messrs. Smith and Gearhart, noting that the meeting was scheduled pursuant to the Supply System Managing Director's desire that members of his staff meet periodically with members of NRC management.

Messrs. Smith and Gearhart stated that they appreciated the opportunity to discuss issues of current interest, and proceeded to discuss the topics outlined in Attachment 3, which was provided to the NRC attendees.

Mr. Gearhart noted during his presentation on Quality Assurance issues that responsibility for Direct Line, the licensee's employee concerns program (ECP), was being assigned to his directorate. He stated that this is being done to provide enhanced management response to employee concerns, which will include followup contact with the employee to confirm that the initial concern was appropriately addressed. He noted that the Supply System would be providing a letter by February 11, 1994, to outline improvements to the ECP.

Mr. Huey noted that the ECP is actually a "safety net," and that line management should have the principal responsibility to ensure that employee concerns are properly addressed at an early stage. Mr. Gearhart agreed, and stated that this is being aggressively addressed with licensee managers. He also noted that the problem evaluation request (PER) process is being changed to require that a copy of all non-accepted PERs, with the reason for non-acceptance, be retained on record.

Mr. Richards thanked the licensee participants for coming to the meeting, and closed by noting that their action plans looked good for the items of interest which had been discussed. He stated that the NRC will continue to monitor the results of their ongoing initiatives and actions.

ATTACHMENT 3

MATERIALS PROVIDED BY THE LICENSEE TO NRC ATTENDEES AT THE FEBRUARY 4, 1994, MANAGEMENT MEETING

(See Attachment 2 of this Report)

Washington Public
Power Supply System

WNP-2

February 1994

Operations Division Focus

WNP-2 Improvements

Quality Assurance Directorate

OPERATIONS DIVISION FOCUS

Accountability must be pushed further down into the organization

Manager/Supervisory Training

All exempt Operations Department personnel are presently attending Manager/Supervisor skills training. These courses include "Interactive Management" and "Managing Performance" modules. Training will be completed prior to the R-9 Refueling Outage.

Changes in the way we do Business in the Control Room

We have successfully moved responsibility downward in the Control Room placing the Shift Manager in more of a management oversight role.

The Shift Manager:

- Attends the daily Maintenance Managers/Supervisor meeting.
- Provides plant status at the morning meeting.
- Frequently attends POC and management decision making meetings.
- Provides oversight of critical "field" activities.
- Improves communications between support groups.

The Control Room Supervisor:

- Reviews and approves all work activities which were previously approved by the Shift Manager.

The "Lead" Control Room Operator position has been developed to perform many of the responsibilities previously handled by the CRS.

The changes were implemented in November 1993.

Supervisory Oversight of Performance

- An Operations Instruction has been developed and implemented to document Operations management expectations for appropriate in-field observation and coaching of department personnel. Each department

manager/supervisor is required to perform frequent observations of tours, procedure implementation, and testing activities on a routine basis. Documented feedback will be provided. The intended result will be a decrease in the number of Operations Department personnel errors due to improved oversight and performance coaching.

This change was completed in December 1993.

"Ownership" of Procedures by the Operating Crews

- Each crew now has ownership of ~75 procedures.
- Each crew member owns 6-8 procedures and will be responsible for the biennial reviews, V&V, and any required changes to their procedures.
- Procedures are aligned to existing Operations Department system experts.
- Procedures will be rewritten in an effort to simplify and add necessary flexibility.

These changes were completed in October 1993.

Improve Operations Problem Assessment and Resolution Skills

- Improve operator turnover process.
- Develop and implement a training module emphasizing effective problem solving using a structured approach.
- Balance simulator training to include more abnormal and transient conditions versus design basis accidents.
- Through management training and improved accountability, encourage participation in decision making.
- Develop and implement a training module on Technical Specification use and interpretation.

Reduce the Number of Equipment Operator Personal Errors

Increased emphasis on self-checking through training.

Increased supervisory oversight and in-field coaching.

OPERATIONS PERSONAL ERRORS

	PERs			
QUARTER	1	2	3	4
1992 PERs	8	20	14	9
1993 PERs	21	26	7	3

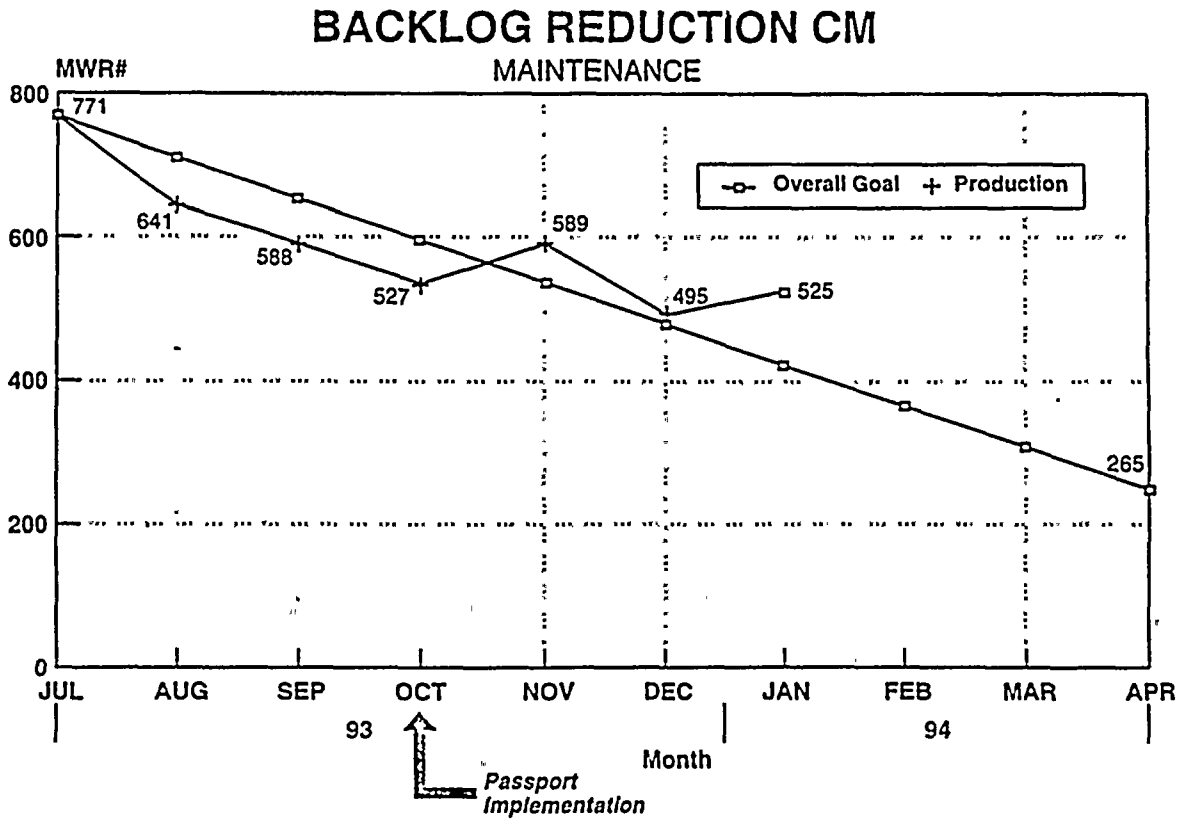
Establish a Shift Manager/SRO Rotational Program

- Increase number of experienced SROs by 10 to 16 over 1.5 years versus planned five years.
- Presently have 6 candidates in class to be examined March 94.
- Hire experienced SROs from the industry or recruit qualified individuals from other WNP-2 organizations.
- License at the SRO level (WNP-2).
- Rotate these individuals and present SROs into the Control Room and to other organizations to ensure a higher level of Operations experience in: Outage Management, Work Control, Maintenance, Training, Licensing, QA, NSAD, etc..
- Benefits for Operations: broadens experience base, skills, increased exposure through specific assignments to critical areas in support of Plant Operations.

Expected Completion Date is October 1995.

Improve the Work Process

- Reevaluate plant working hours to provide more backshift support (to be implemented following R-9).
- Continued efforts to implement and streamline the PASSPORT and Total Exposure System.
- Continue efforts to improve the schedule to accurately represent what is being worked.
- Regain the previous trend in backlog reduction.



R-9 Challenges

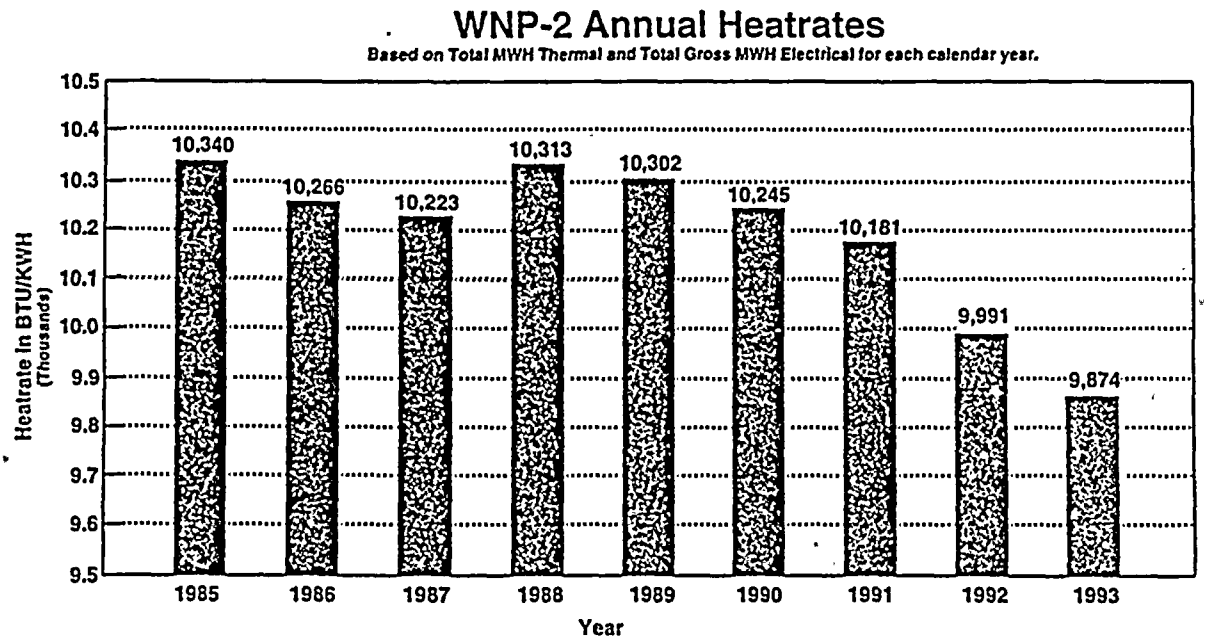
- Reduce personnel errors in the areas of:
  - Tagouts
  - Lineups
  - Refuel floor
- Minimize exposure in an outage with significant radiological challenges:
  - Jet Pump Beam Replacement
  - Control Rod Drive Changeouts
  - Nozzle and Safe end stress reduction
  - SRV changeouts

WNP-2 IMPROVEMENTS

Unit Operation

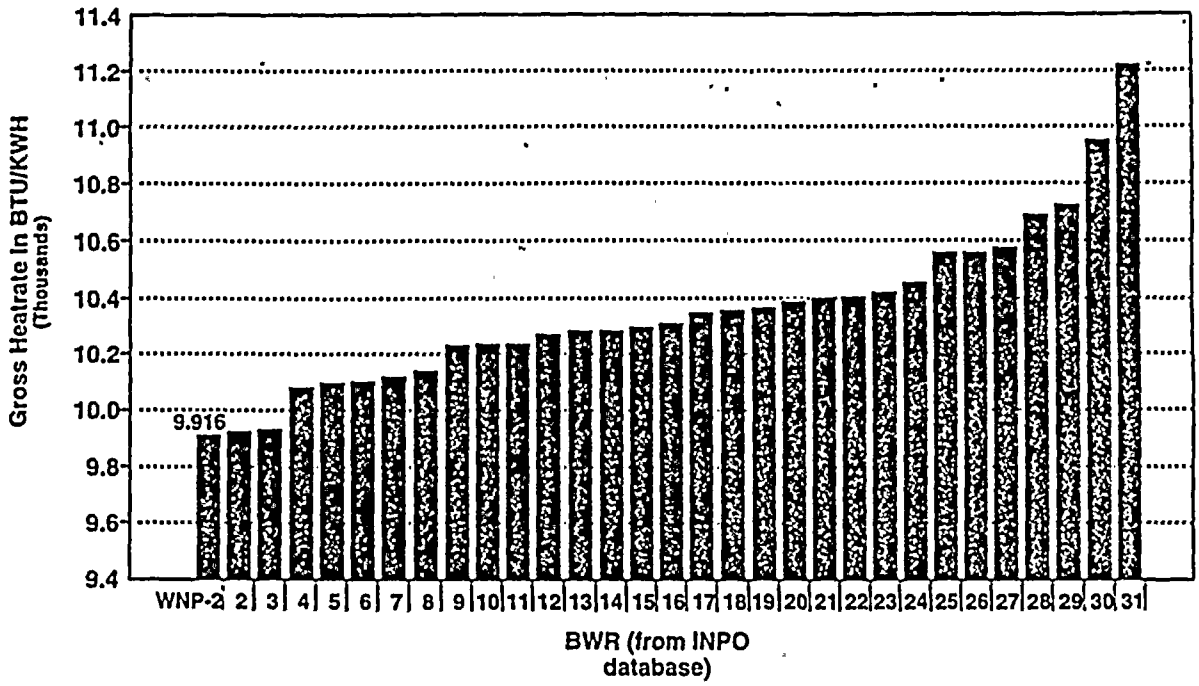
Thermal Performance

Unit availability



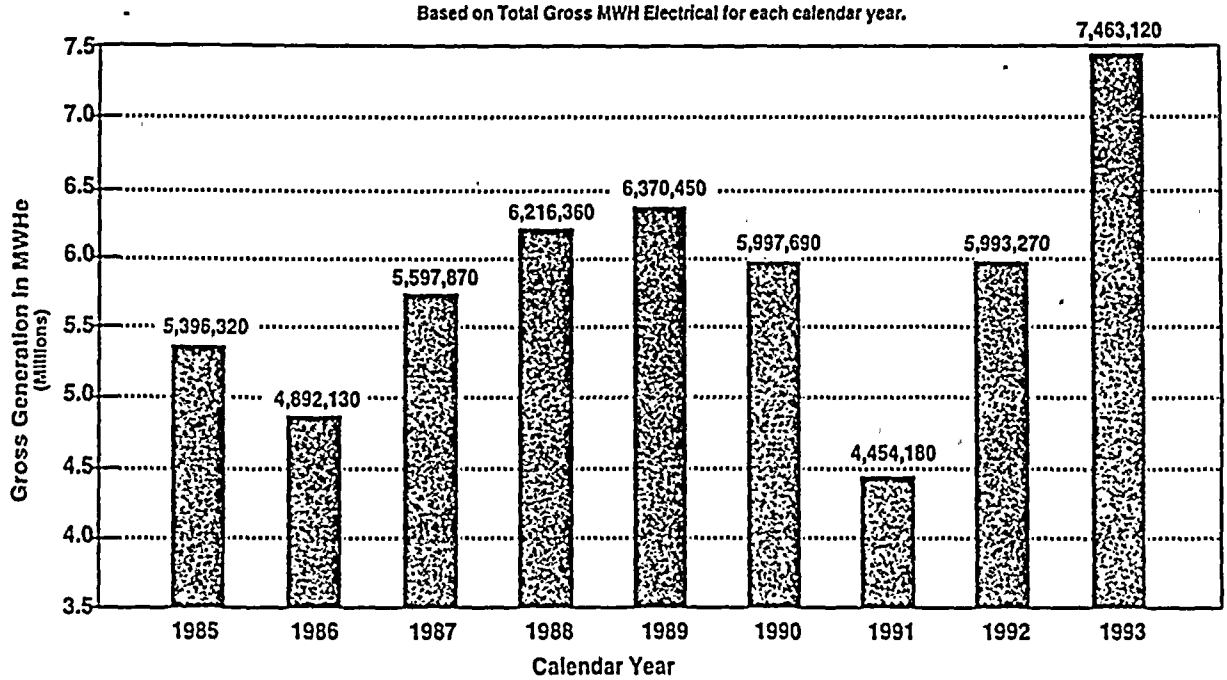
COMPARISON OF 31 BWRs- INPO DATA

Based in INPO data from July 1, 1992 through June 30, 1993



WNP-2 Annual Gross Generation

Based on Total Gross MWH Electrical for each calendar year.



Calendar Year Generation
for WNP-2

	Gross Gen. MW-Hrs	Net Gen. MW-Hrs	Capacity Factor	Avail. Factor
1993	7,463,120	7,134,966	75.0%	77.2%
1992	5,993,270	5,692,380	59.7%	62.7%
1991	4,454,180	4,229,869	44.3%	47.9%

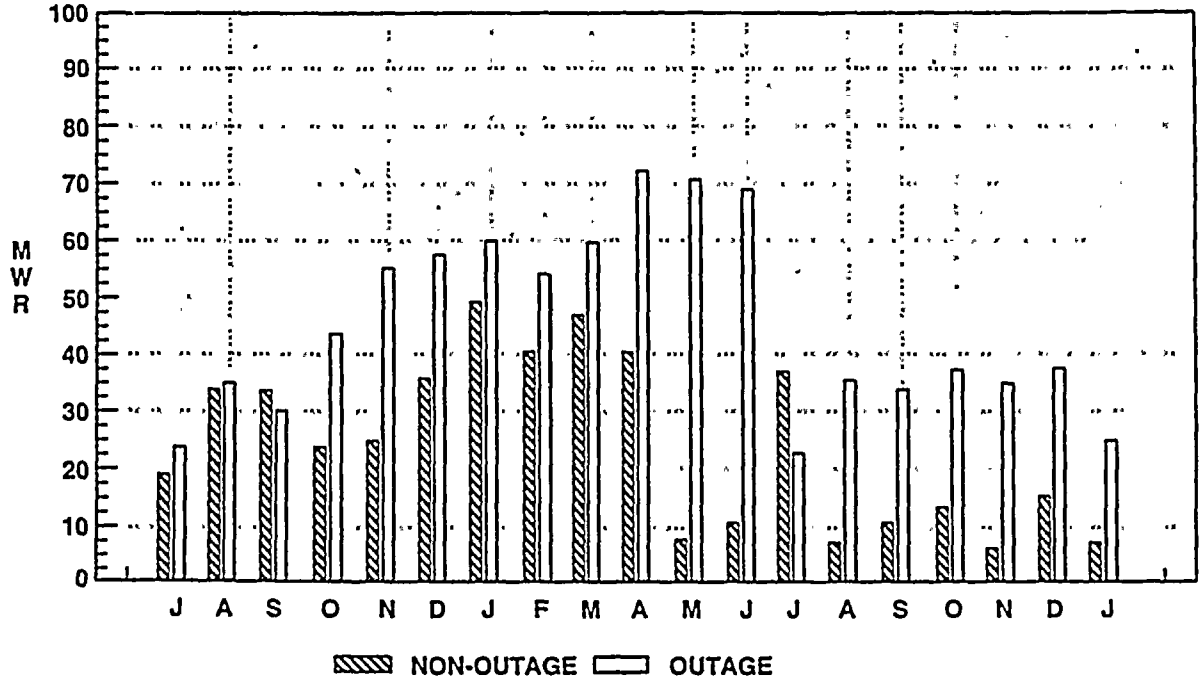
Performance Evaluations
Jan. 1994

Benchmarking trips served as a stimulus for change

- SRO rotation program
- Reorganization of Control Room responsibilities
- Operator's ownership (control room deficiencies + TMRs)

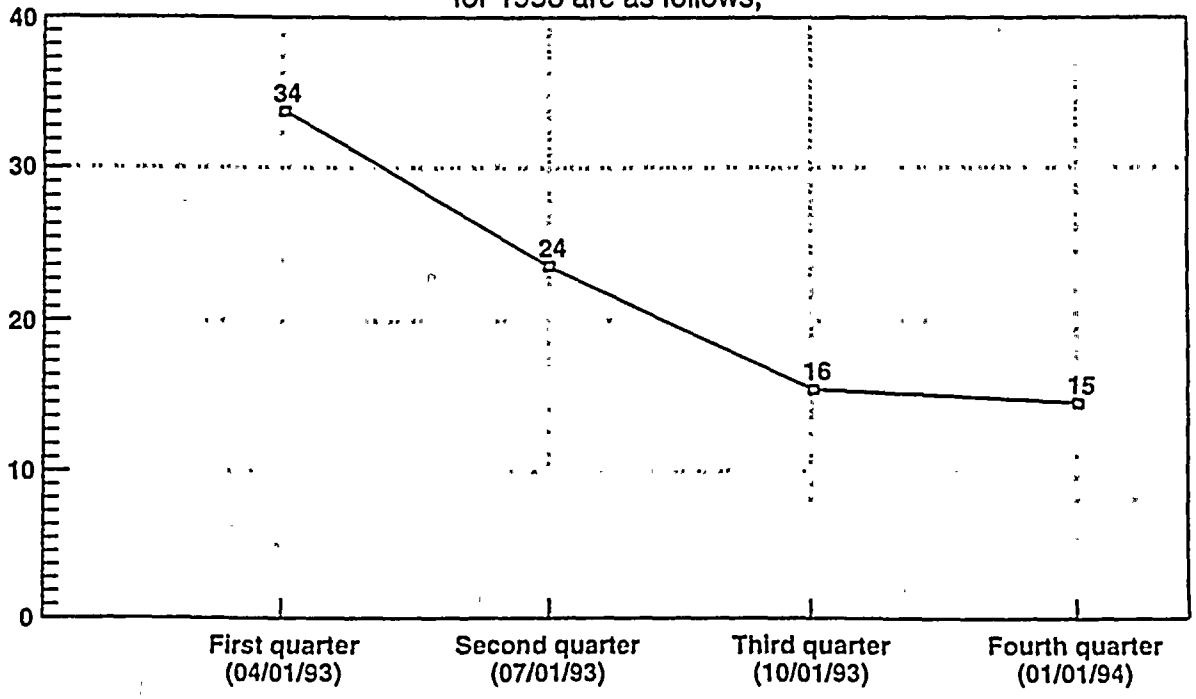
CONTROL ROOM DEFICIENCIES

NON-OUTAGE AND OUTAGE (7/92 TO 1/94)



TMR TRENDING

The number of open TMRs at the end of each calendar quarter for 1993 are as follows;

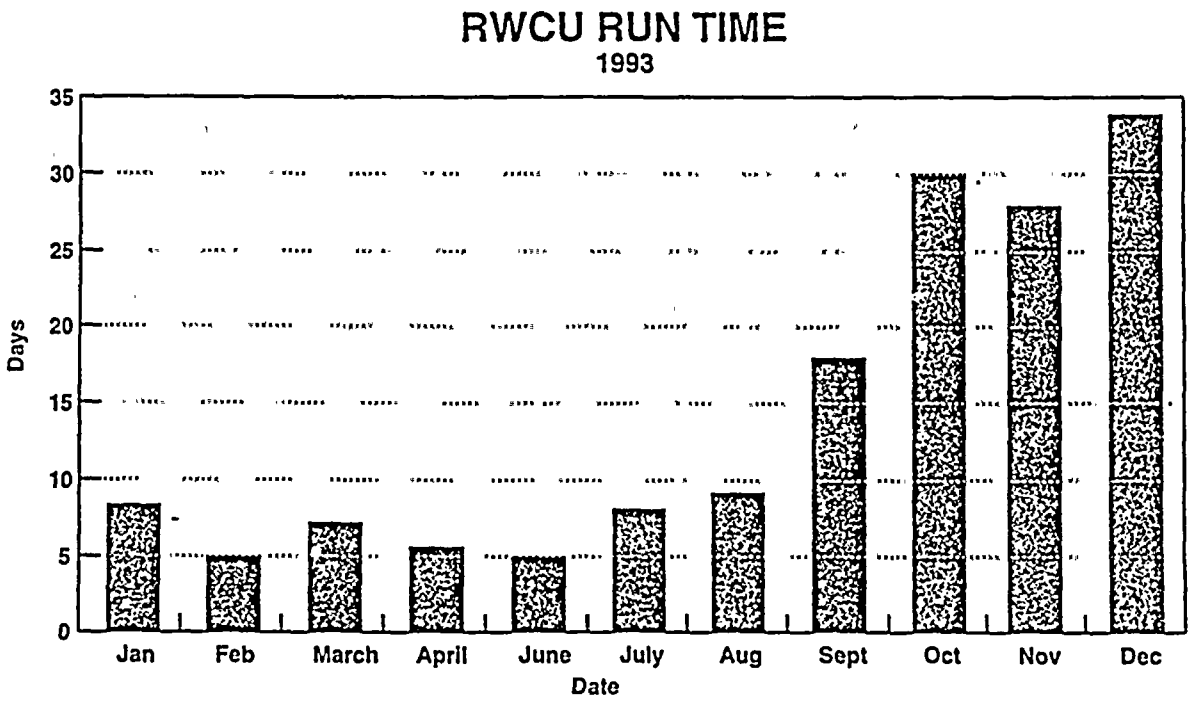


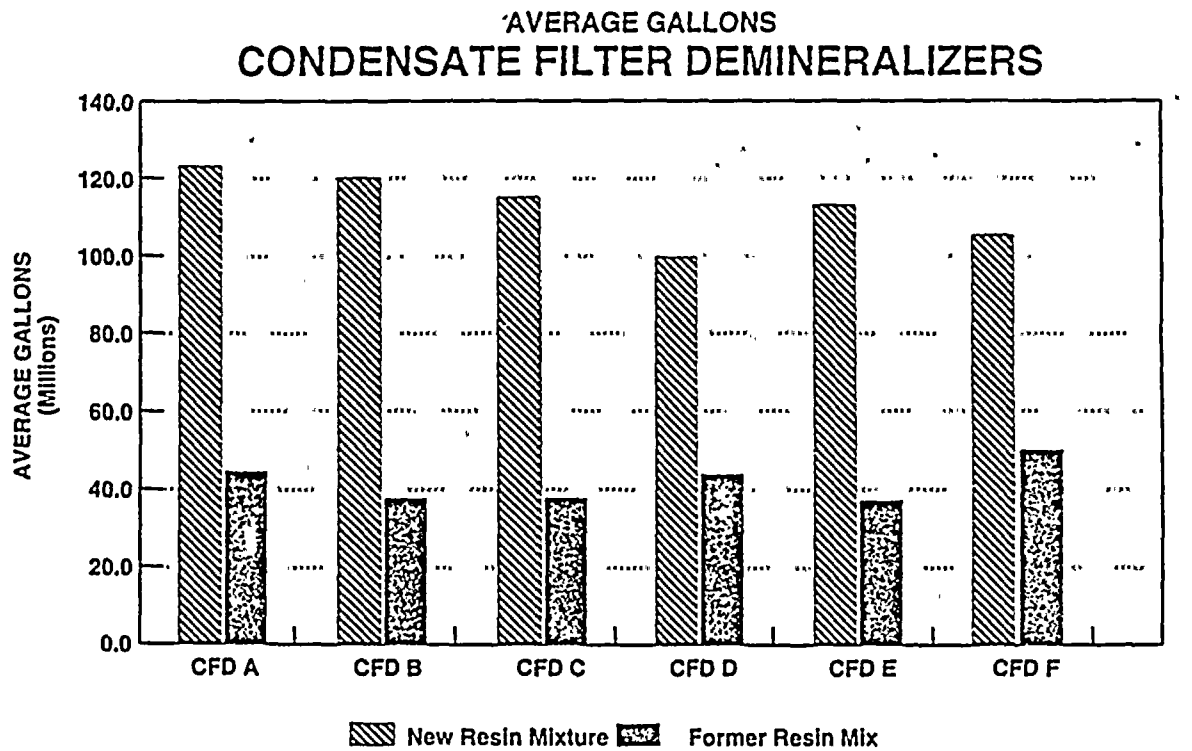
Chemistry Parameters

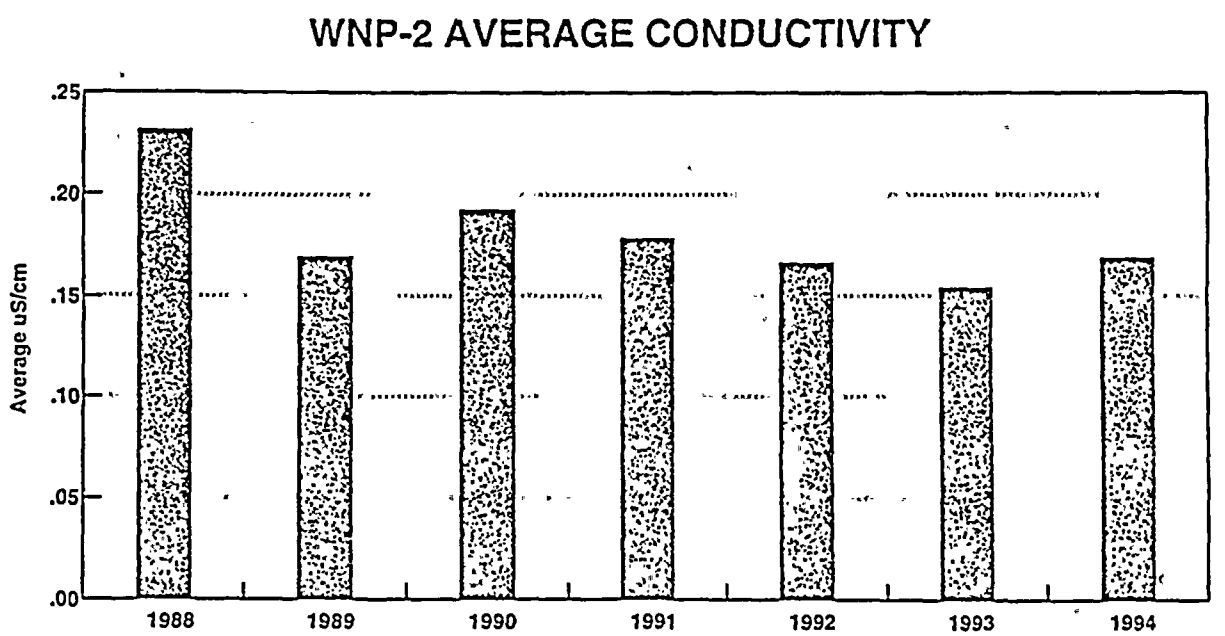
Condensate filter demineralizer run lengths

RWCU run lengths

Reactor water chemistry




AVERAGE GALLONS
CONDENSATE FILTER DEMINERALIZERS
AVERAGE GALLONS (Millions)
140.0
120.0
100.0
80.0
60.0
40.0
20.0
0.0
CFD A
CFD B
CFD C
CFD D
CFD E
CFD F
New Resin Mixture
Former Resin Mix


WNP-2 AVERAGE CONDUCTIVITY
Average uS/cm
.25
.20
.15
.10
.05
.00
1988
1989
1990
1991
1992
1993
1994

QUALITY ASSURANCE DIRECTORATE

Quality Assessment Division - Jeff Benjamin

- Plant Assessment - Joe Muth, 10 Technical Specialists and Engineers
- Plant Support Assessment - Stan Davison, 9 Technical Specialists and Engineers
- Quality Control - Cliff Edwards, 12 Engineers and Technical Specialists
- WNP-1/3 Quality Assurance - Tom Houchins, 1 Technical Specialist

Successes

- Organizational transition
- Revised procedures
- Revised expectations
- Additional Operations training

Challenges

- Assessments
  - Integrating 1 new manager and 8 new QA people
  - Implementation of Functional Area concept
  - Upgrading individual performance in Audits and Surveillance efforts
  - Upgrading training for all Assessment staff
  - Upgrading performance on item follow-up
- Quality Control
  - Reevaluating the inspection process/methodology
  - Upgrading individual performance
  - Upgrading training/certification program for QC staff

Quality Support Division - John McDonald

- Operating Event Analysis & Resolution - Dusty Rhoads, 8 Engineers & Technical Specialists
- Nuclear Safety Assurance - Steve Washington, 6 Engineers & Technical Specialists
- Procurement Quality Assurance - Gary Wooley, 10 Engineers & Technical Specialists

Successes

- Supporting Root Cause transition
- Coaching line personnel in cause analysis/corrective action
- Revised expectations
- Increased ISEG involvement with operations

Challenges

- Operating Event Analysis & Resolutions
  - Redefinition of role in Root Cause process
  - Integration of new personnel
  - Refined trending
- Nuclear Safety Assurance
  - Redefinition of role and methods
  - Timeliness of effort
- Procurement Quality Assurance
  - Maintain performance while improving efficiency

Directorate Challenges/Initiatives

- Responsibility for PER program management
- Responsibility for Direct Line investigation/follow-up
- Centralize trending/performance monitoring

Corrective Action Program

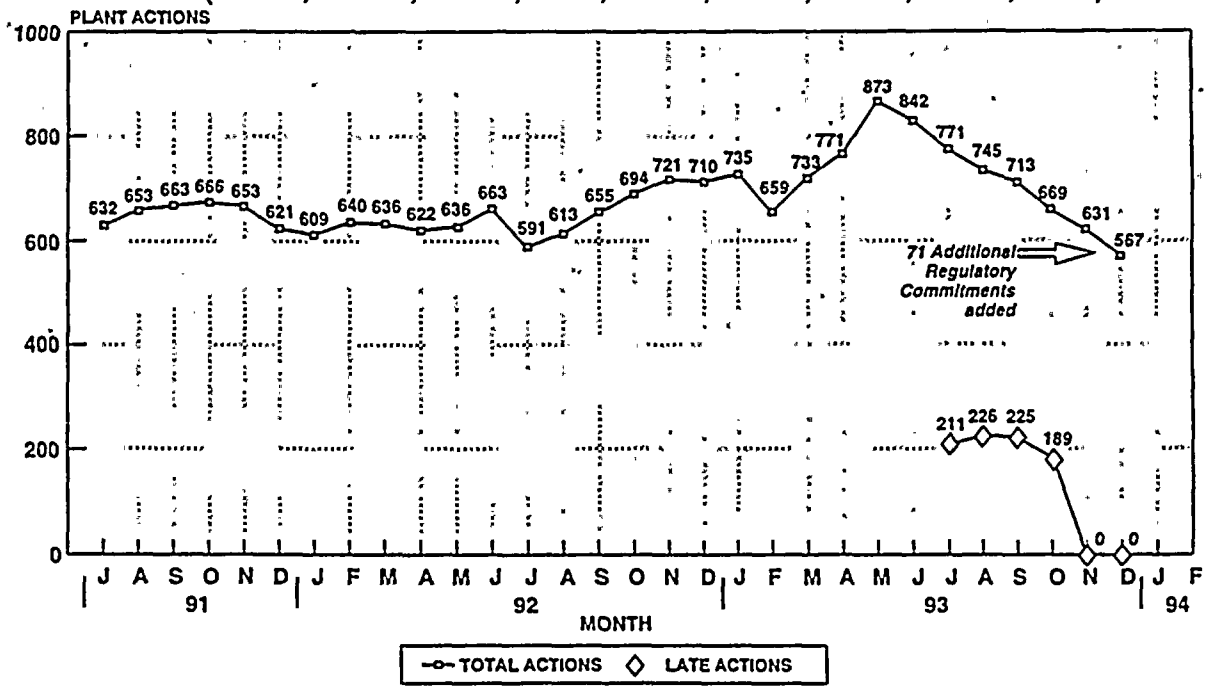
- Successes
  - Improvements in timeliness of evaluations
  - Improvements in tracking and meeting commitments

- Areas for Improvement
  - Completeness of the problem description
  - Use and timing of prompt operability process
  - Quality of proposed corrective actions

- Actions
  - Formed process user group to propose changes
  - QA Assessments in November and January
  - Plant Manager review of PERs
  - QA review of significant deficiencies

TOTAL PLANT ACTIONS VS. LATE PLANT ACTIONS

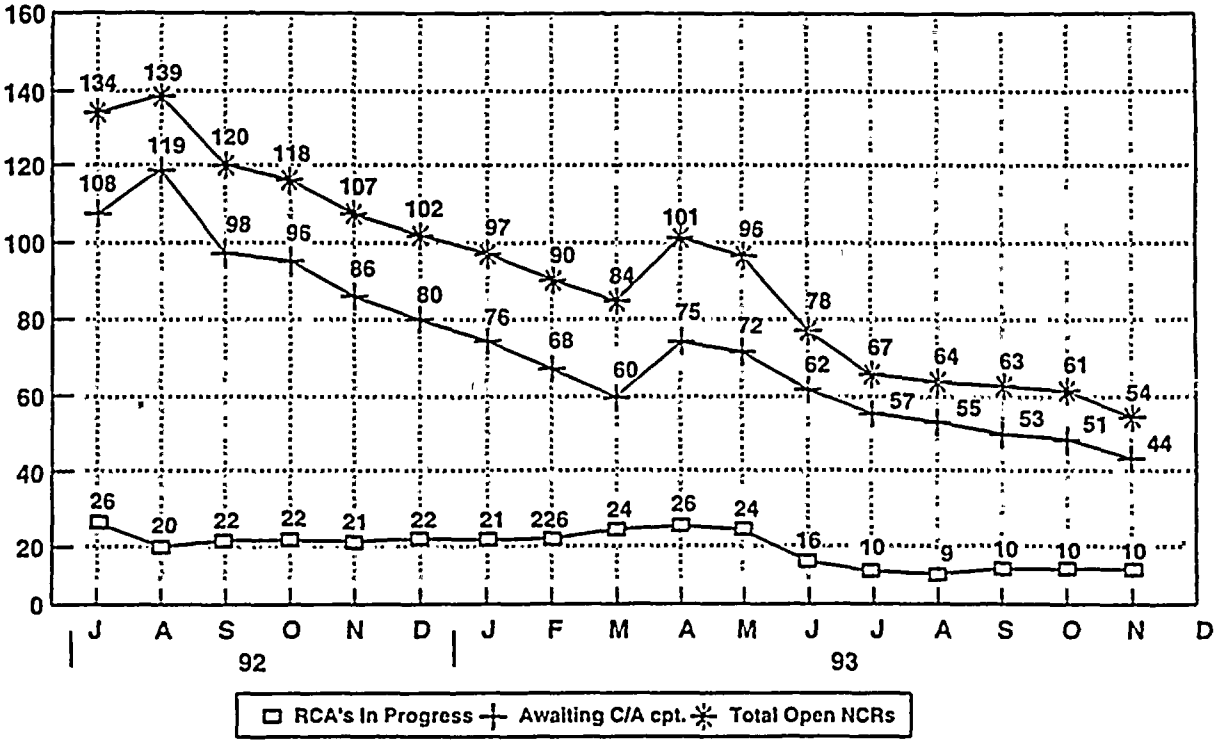
(NCRAs, MDRAs, PDRAs, OERs, REGNs, REGSs, PERAs, QFRAs, EMCs)



As of January 1993 Totals Include Long Term Actions

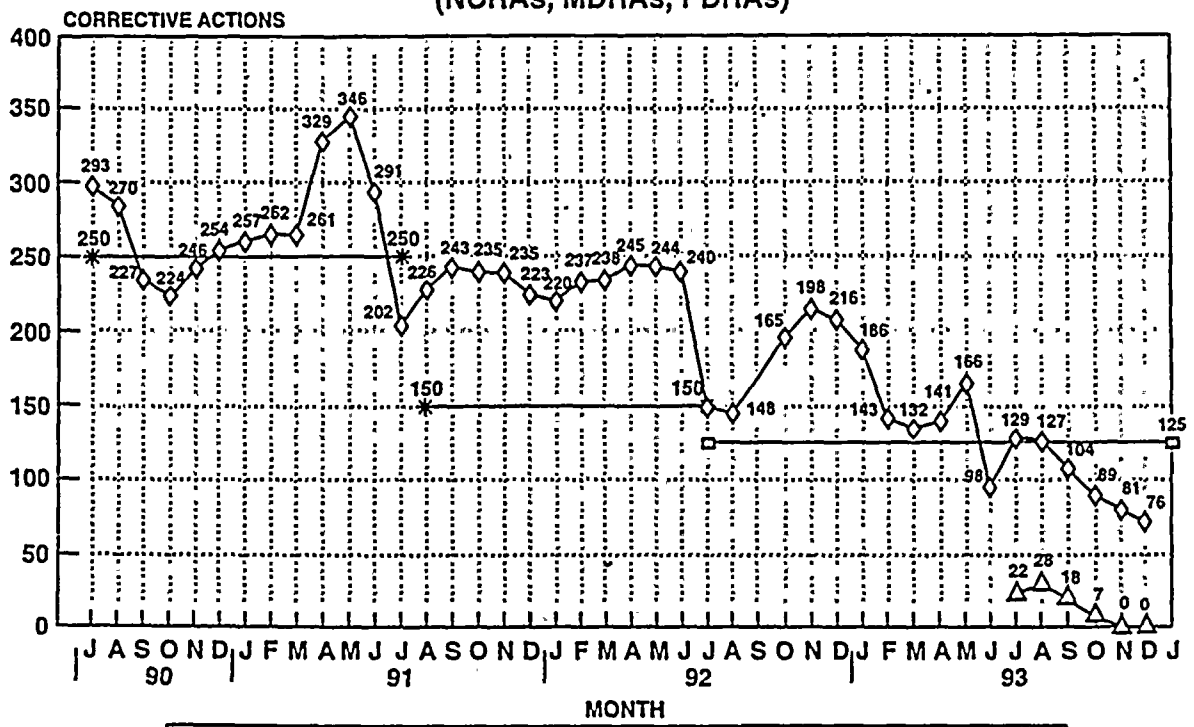
SIGNIFICANT DEFICIENCY REPORTS

Open NCRs, Includes Open Investigations and those Awaiting C/A completion



OPEN CORRECTIVE ACTIONS VS LATE

(NCRAs, MDRAs, PDRAs)



TOTAL DOES NOT INCLUDE LONG TERM C/As AND C/As AWAITING ADMINISTRATIVE CLOSURE