

U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No. 50-344/91-17  
Docket No. 50-344  
License No. NPF-1  
Licensee: Portland General Electric Company  
121 S.W. Salmon Street  
Portland, OR 97204

Facility Name: Trojan

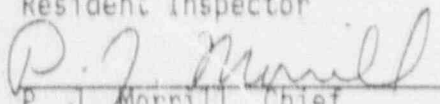
Inspection at: Rainier, Oregon

Inspection conducted: May 12 - June 22, 1991

Inspectors: R. C. Barr  
Senior Resident Inspector

J. F. Melfi  
Resident Inspector

Approved By:

  
P. J. Morrill, Chief  
Reactor Projects Section 1

7/26/91  
Date Signed

Summary:

Inspection on May 12 - June 22, 1991 (Report 50-344/91-17)

Areas Inspected: Routine inspection of operational safety verification, maintenance, surveillance, follow-up of events, follow-up of temporary instructions, follow-up of noncompliances, and follow-up of open and unresolved items. Inspection procedures 25505, 30703, 37700, 61726, 62700, 62703, 71707, 90712, 92700, 92701, 92702 and 93702 were used as guidance during the conduct of the inspection.

Results

General Conclusions and Specific Findings

Strengths/Improvements

During this inspection period, the inspectors noted improved performance in the area of event evaluation/root cause identification. Evaluation of facility events generally appeared more timely and thorough.

### Weaknesses

During this inspection period, the following weaknesses were identified and brought to management's attention:

o Weak Administration of the Temporary Modification (TM) Program:

Paragraphs 4, 6, and 7 describe instances of poor administration of the Temporary Modification Program. Required audits were not consistently performed as required by facility instructions, the average longevity of TMs is high and PGE workers are not consistently complying with TM administrative requirements.

o Weak Maintenance Work Practices:

Paragraph 5 describes noncompliance with work instructions by maintenance personnel and inadequate supervision of maintenance activities.

o Weak Review of Licensing Documents

Paragraph 5 describes the inadequate review of an NRC Safety Evaluation Report by both the licensing group and the inservice testing group.

### Significant Safety Matters

None

### Summary of Violations and Deviations

Six violations, three cited and three non-cited, were identified. No deviations were identified.

### Open Items Summary

One open item (Paragraph 9), one unresolved item (Paragraph 9). Three enforcement items (Paragraph 12) and three LERs (Paragraph 13) were closed.

## DETAILS

### 1. Persons Contacted

#### a. Portland General Electric

- \*J. E. Cross, Vice President, Nuclear
- \*W. R. Robinson, Plant General Manager
- G. D. Hicks, General Manager, Plant Support
- C. K. Seaman, General Manager, Nuclear Quality Assurance
- \*T. D. Walt, General Manager, Technical Functions
- C. P. Yundt, General Manager, Trojan Excellence
- A. R. Ankrum, Manager, Nuclear Security
- \*R. L. Gridley, Acting Manager, Nuclear Safety and Regulation
- M. B. Lackey, Manager, Planning and Control
- W. O. Nicholson, Manager, Operations
- W. F. Peabody, Manager, Nuclear Plant Engineering
- R. L. Russell, Outage Manager
- M. J. Singh, Manager, Plant Modifications
- J. F. Whelan, Manager, Maintenance
- G. P. Enterline, Branch Manager, Operations
- J. Mody, Branch Manager, Plant Systems Engineering
- \*D. L. Nordstrom, Branch Manager, Quality Operations
- J. D. Reid, Branch Manager, Quality Support Services
- G. L. Rich, Branch Manager, Radiation Protection
- J. J. Taylor, Branch Manager, PM/EA
- \*W. J. Williams, Branch Manager, Nuclear Compliance
- J. A. Benjamin, Supervisor, Quality Audits
- D. J. Harvey, Compliance Engineer

#### b. Oregon Department of Energy

- A. Bless, Resident Engineer

The inspectors also interviewed and talked with other licensee employees during the course of the inspection. These included shift supervisors, reactor and auxiliary operators, maintenance personnel, plant technicians and engineers, and quality assurance personnel.

\*Denotes those attending the exit interview.

### 2. Plant Status

The inspection period began with the plant in Mode 6, Refueling. The core was refueled and upper reactor internals were in place. On May 30, 1991, at 5:00 pm the plant entered Mode 5, Cold Shutdown. At the conclusion of the inspection period licensee and contract craftsmen were performing 1991 Refueling Outage maintenance.

### 3. Operational Safety Verification (71707)

During this inspection period, the inspectors observed and examined activities to verify the operational safety of the licensee's facility.

The observations and examinations of those activities were conducted on a daily, weekly or biweekly basis.

Daily the inspectors observed control room activities to verify the licensee's adherence to limiting conditions for operation as prescribed in the facility Technical Specifications. Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions, trends, and compliance with regulations. On occasions when a shift turnover was in progress, the turnover of information on plant status was observed to determine that pertinent information was relayed to the oncoming shift personnel.

Each week the inspectors toured the accessible areas of the facility to observe the following items:

- (a) General plant and equipment conditions.
- (b) Maintenance requests and repairs.
- (c) Fire hazards and fire fighting equipment.
- (d) Ignition sources and flammable material control.
- (e) Conduct of activities in accordance with the licensee's administrative controls and approved procedures.
- (f) Interiors of electrical and control panels.
- (g) Implementation of the licensee's physical security plan.
- (h) Radiation protection controls.
- (i) Plant housekeeping and cleanliness.
- (j) Radioactive waste systems.
- (k) Proper storage of compressed gas bottles.

Weekly, the inspectors examined the licensee's equipment clearance control with respect to removal of equipment from service to determine that the licensee complied with technical specification limiting conditions for operation. Active clearances were spot-checked to ensure that their issuance was consistent with plant status and maintenance evolutions. Logs of jumpers, bypasses, caution and test tags were examined by the inspectors.

Each week the inspectors conversed with operators in the control room, and with other plant personnel. The discussions centered on pertinent topics relating to general plant conditions, procedures, security, training and other topics related to in-progress work activities.

The inspectors examined the licensee's Corrective Action Program (CAP) to confirm that deficiencies were identified and tracked by the system. Identified nonconformances were being tracked and followed to the completion of corrective action.

Routine inspections of the licensee's physical security program were performed in the areas of access control, organization and staffing, and detection and assessment systems. The inspectors observed the access control measures used at the entrance to the protected area, verified the integrity of portions of the protected area barrier and vital area barriers, and observed in several instances the implementation of compensatory measures upon breach of vital area barriers. Portions of the isolation zone were verified to be free of obstructions.

Functioning of central and secondary alarm stations (including the use of CCTV monitors) was observed. On a sampling basis, the inspectors verified that the required minimum number of armed guards and individuals authorized to direct security activities were on site.

The inspectors conducted routine inspections of selected activities of the licensee's radiological protection program. A sampling of radiation work permits (RWP) was reviewed for completeness and adequacy of information. During the course of inspection activities and periodic tours of plant areas, the inspectors verified proper use of personnel monitoring equipment, observed individuals leaving the radiation controlled area and signing out on appropriate RWPs, and observed the posting of radiation areas and contaminated areas. Posted radiation levels at locations within the fuel and auxiliary buildings were verified using both NRC and licensee portable survey meters. The involvement of health physics supervisors and engineers and their awareness of significant plant activities was assessed through conversations and review of RWP sign-in records.

The inspectors verified the operability of selected engineered safety features. This was done by direct visual verification of the correct position of valves, availability of power, cooling water supply, system integrity and general condition of equipment, as applicable.

No violations or deviations were identified.

4. Incorrect Restoration of Temporary Modification (TM) 90-051 (71707, 92701)

On May 27, 1991, the facility was in Mode 6, refueled, reactor vessel level at 65 feet 9 inches. Preparations were being made to set the reactor vessel head. During a routine control room operational safety tour, the resident inspector noted that the indicators for one of the three narrow range pressurizer level channels and the wide range pressurizer level channel were reading incorrectly. With the pressurizer drained, level transmitters (LT) 461 and 462 were reading 38% and 100%, respectively. The inspector discussed the apparent incorrect level indication with the shift supervisor. The shift supervisor stated he did not understand why the indicators were reading as they were. He stated he was not overly concerned since, at that time, the indicators were providing no safety function. He also noted that the incorrect indication may have something to do with TM 90-051.

On May 29, 1991, the resident inspector examined the TM log and found the log indicated TM 90-051 had been restored (returned to original configuration) on May 3, 1991.

On May 31, 1991, the inspector, during the daily operational safety tour, noted that the pressurizer level indicators read as they had on May 27, 1991, and that the TM tags were still posted. Not removing the TM tags was an apparent violation of Trojan Administrative Order (AO) 5-8, Revision 6, step 4.6.3.b. The inspector requested the shift supervisor to generate a corrective action request (CAR) to investigate the cause of the incorrect pressurizer level indication.

The shift supervisor generated CAR C91-0490 to evaluate this event. The licensee's evaluation found that TM 90-051 had been improperly restored. While the work required by the TM had been performed, the post maintenance testing (PMT) for the work had not been performed and the TM tags had not been removed.

The licensee's evaluation also found that a PGE foreman had signed that the TM tags had been removed, even though the tags had not been removed. As corrective actions for this event, the licensee removed the temporary modification tags, counselled the foreman on the error he had made, committed to revise AO 5-8 and committed to re-evaluate the maintenance craft training program. Additionally, the licensee counselled the shift supervisor on the need to conduct timely investigations as to the cause of erroneous indications. The violation is not being cited because the criteria specified in section V.A. of the Enforcement Policy were satisfied.

The resident inspector discussed this event with the shift supervisor that investigated the event, the foreman who improperly signed off that the TM tags had been removed, the control operator who logged that the TM had been restored, and plant management. The foreman pointed out that he had not been trained on AO 5-8, but that he had been "grandfathered" on the training because he had been a long time employee. He also stated he had not restored a temporary modification in the last three years. He noted that he attempted to locate and could not find the tag that was suppose to be hanging on the valve. The tag was subsequently located hanging on a support about three feet away. He also stated that he requested the control operator to remove the two tags on the control boards located in the control room. In a discussion the inspector had with the control operator, he stated he remembered logging that TM 90-051 had been restored, but he did not recall the specifics of the conversation with the foreman. Finally, the foreman stated he felt he was rushed by outage management because MR 90-10598, the work required to restore TM 90-051, was the critical path job that had to be completed prior to filling the reactor vessel.

The inspector concluded that the following contributed to the event: the foreman signed that he had performed a task for which he had not been formally trained; the foreman had not been formally trained or retrained on AO 5-8; the craftsman that hung the TM tags did not document the actual location where he hung the TM tags; AO 5-8 is a poorly written procedure; and communications between the foreman and the control operator were inadequate.

One noncited violation was identified.

#### 5. Maintenance (62703)

This maintenance observation of the reassembly and disassembly of the B Residual Heat Removal (RHR) pump was a continuing observation from the inspection described in report 50-344/91-12. At the end of that inspection, the pump and motor had been reassembled. Upon initial rotation by hand, licensee craftsmen detected contact between the pump impeller and diffuser. During the disassembly of the pump, the craftsmen

found the lower part of the shaft was bent 17 mils total indicated runout (TIR). This equates to a shaft deflection of 8.5 mils. The vendor stated with that amount of shaft deflection, the shaft had to have been distorted during the pump maintenance, as the pump would not have operated with that amount of shaft distortion.

a. Second Reassembly

The licensee located a replacement rotating assembly (shaft with rotor) in their Longview, Washington warehouse. The assembly was one of two that had been procured in 1980 as possible replacements for an earlier RHR pump problem.

Licensee craftsmen inspected the rotating assembly to assure themselves that the component was in fact an RHR pump shaft. During this inspection, licensee mechanics checked several dimensions of the shaft; however, not all the critical dimensions were checked. Since the shaft of the previous assembly was bent, the straightness of the new assembly was checked and found to have a 1 mil deflection. The licensee and the vendor considered this amount of deflection acceptable.

During reassembly, licensee craftsmen found two parts, a spring and a spacer, that were not identified on the lower bearing housing drawing. The vendor stated that Westinghouse had in some cases added these parts to their pump without updating the drawings. The vendor stated it would be permissible to leave these parts in the pump. Licensee craftsmen also noted the shaft was magnetic; therefore, the shaft material was different from the original shaft material. The replacement shaft was 410 stainless steel versus grade 304 stainless of the previous shaft. These grades of stainless steel have slightly different chemical compositions and physical properties. The licensee issued a Spare Parts Engineering Evaluation Report (SPEER) to document the metal composition difference. Per MR 91-3616, the motor bearing and pump bearings were reassembled with the new shaft.

During final preparations to run the pump following this reassembly, the craftsmen filled the lower bearing to a halfway mark on the oil sight glass per the work instructions of MR 91-1343. The worker recognized that the oil level was slightly higher than the previous running level. During pump post maintenance testing (PMT), craftsmen identified an oil leak and discussed the leak with the vendor. The vendor stated that the additional oil (overfill) was the probable cause of the leak. The vendor stated the oil would seek its own level in the lower bearing assembly. The worker reduced the level to the previous running level. During the PMT monitoring, the pump was stopped and started several times per MRs 91-3903 and 91-3907. The oil leakage decreased until finally no further leakage was observed. At 5:25 a.m. on May 18, 1991, the pump was declared operable. At 1:01 pm, the B RHR pump was used to pump down the upper refueling cavity. This evolution completed at 7:25 pm. During the repositioning of RHR valves following the pump down of the cavity, the auxiliary operator found that the B RHR pump

had no indicated oil level in its sightglass. At 7:50 pm, plant operators again declared the B RHR pump inoperable. Because TS 3/4.9.8.2 requires both RHR pumps operable when reactor vessel water level is less than 23 feet above the reactor vessel flange, plant operators returned reactor cavity water level to 91 feet.

b. Third Disassembly/Reassembly

The B RHR pump oil was drained per MR 91-3903. Eighty-one ounces of blackened oil were collected. Because this volume of oil remained in the bearing, no bearing damage occurred. Per MRs 91-3907 and 91-3908, the pump and motor were again disassembled. Licensee craftsmen identified that the oil metering plate was worn. From oil sample analysis results, the licensee concluded the oil was blackened due to the metal wear products from the metering plate. In response to this finding, the licensee formed an Event Review Team (ERT) to determine the causes of the RHR pump maintenance errors.

Upon disassembly, licensee craftsmen measured critical dimensions of the shaft and found that certain dimensions were incorrect. Specifically, the indent where the lower bearing and bearing runner fit against the shaft was 0.1 inches (100 mils) longer than on the previous shaft. This, in conjunction with the spring and spacer, forced the oil metering plate to contact the bearing runner. This caused the metal to metal contact and oil leakage discussed in the above paragraphs.

Licensee engineers and craftsmen discussed the rubbing metering plate and the loss of oil with the vendor. The vendor advised the licensee to remove the spring and spacer from the lower bearing assembly. The vendor stated the spring and spacer ensured that any excess play was removed from the lower bearing by assuring that the shaft was aligned correctly during initial rotation checks. The licensee concurred with the vendor's recommendations and removed the parts.

Licensee craftsmen then reassembled the RHR pump and motor. The inspector observed portions of the reassembly, including the lower bearing reassembly. During the observation of work associated with MR 91-3908, the inspector noted that the lower bearing was heated to approximately 240 degrees F. vice to less than 200 degrees F. as stated in the MR work instructions. This was an apparent violation of MR 91-3908 work instructions (50-344/91-17-03). The inspector did not observe the worker heating the bearing read the instructions. He also noted that the maintenance supervisor, who was a craftsman upgraded to a supervisor for the outage, was not supervising the activity. The inspector immediately brought the noncompliance to the attention of the workers. The work was stopped, a licensee supervisor was contacted, and the supervisor concluded it was acceptable to continue with the work because the bearing had not been damaged.

The licensee wrote CAR 91-0432 to investigate the bearing overheating event. The CAR evaluators also determined there was no damage to the bearing since the vendor instructions allow the bearing to be heated to a maximum of 230 degrees F. The CAR evaluators also noted that the pyrometer used to measure the bearing temperature was not in calibration. The CAR evaluators found that the pyrometer calibration expired on May 1 and was issued on May 21 contrary to lower tier Maintenance Department Procedure (MDP) 1-10 that states "the toolroom is not to issue a tool for use that does not have a current calibration sticker." As corrective actions for the bearing overheating event, the licensee counselled the task supervisor and the worker who had overheated the bearing, dismissed the contract tool room worker that issued the pyrometer and issued a stop work order.

After reassembling the pump and filling the pump's suction line, licensee craftsmen identified a leak at the pump seal line threaded fitting. The craftsmen repaired the leak by using Permatex. The licensee concluded the leak was due to using an inappropriate sealant, Graphol. The craftsmen stated that there was not a good equivalent to use for threaded fittings since teflon tape was no longer authorized. At the conclusion of this inspection, the licensee was evaluating sealants for their compatibility with stainless steel.

For this maintenance observation, the inspector concluded licensee supervision was inadequate, work instructions were not consistently followed, and adequate controls were not established to ensure the RHR shaft was a like-for-like replacement.

c. RHR PMT Surveillance (61726, 93702)

The inspector requested that the Shift Supervisor notify him just prior to conducting the PMT so he could observe the test; however, the Shift Supervisor forgot. As a result, the inspector obtained and reviewed the PMT data the licensee craftsmen and engineers collected.

Periodic Operating Test (POT) 16-1, "Residual Heat Removal System Pump and Valve In-Service Test" was the governing procedure for the pump's PMT and surveillance test. The PMT was to be performed to meet In-Service Test (IST) requirements of the ASME Section XI code.

The inspector identified the following two items of concern during his review of the PMT: not performing the test in full compliance with the IST code and the potential effects of the repaired pump's performance on the A train pump.

The IST code (IWP-3111) requires after pump repair or replacement, a new set of reference values be determined. One of these reference values is bearing temperature. The licensee did not take bearing temperature measurements. The inspector learned the bearing temperatures were not taken because the licensee IST organization thought Trojan had been granted relief from that requirement

(letter, Dyer to Cross, 2/28/91). The inspector's review of the letter found bearing temperature and vibration amplitude measurement were no longer required provided the requirements of ASME OMa-1988, part 6 were implemented to obtain vibration velocity measurements. The inspector determined that the licensee had not yet implemented this new code, but planned to implement it by the end of 1991.

The licensee related to the inspector that maintenance measured bearing vibration velocities in three places for informational purposes. The new code specifies vibration velocity measurements axially and two measurements orthogonally on each bearing (five places).

In researching this issue, the IST group found that mechanical maintenance fortuitously took vibration velocity readings at the five correct locations following the third pump reassembly. The inspector verified that the points selected were appropriate and the instrumentation used was in calibration.

Because the RHR pump was declared operable on May 16, 1991, without performing the required IST testing, this was an apparent violation. The inspector concluded this error was made because the Licensing and the IST organization failed to adequately review the NRC safety evaluation of the PGE waiver request. As corrective actions the licensee will comply with the old code until they procedurally implement the new IST testing requirements. To prevent recurrence of this event, the licensee will document their review of licensing documents and forward the review to the action organization. The violation is not being cited because the criteria specified in Section V.A. of the Enforcement Policy were satisfied.

Because both RHR pumps share a common discharge header and have only one check valve immediately downstream of each pump, it is possible to have the A train pump running without flow (i.e. deadheaded), if the B train pump discharge head is sufficiently greater than that of the A pump. The pump manufacturer stated that the pump should not be allowed to run with less than 100 gpm through the pump. The licensee independently recognized this and performed part of POT 16-1 to assess pump to pump interaction. The inspector observed the test.

Various head versus differential pressure readings were taken (at approximately 1500, 2000, 3000 gpm and runout flow) to determine the pump head curves. Starting with the A train pump, these readings were taken. The flow was subsequently reduced to approximately 3000 gpm and the B train pump was started. The flow readings on the A train pump dropped to zero and the A train pump was secured. The B train pump was then tested at similar flows as the A train pump. The pumps demonstrated a significant interaction. The licensee wrote Corrective Action Request (CAR) 91-0515 to document this pump interaction issue.

The inspector reviewed the data and determined that both pumps' flow were above assumed safety analysis values. The inspector further

determined that the A pump was operating at approximately 93% of its original pump head curve and the B pump was operating at about 99% of its original pump head curve.

To resolve this problem PGE plans to install a new check valve in the A train. The licensee discussed the scope of this modification with the inspector, and the inspector concluded the check valve should stop the pump interaction problem. The inspector was also told that this modification would be performed prior to restart from this refueling outage.

One apparent violation and one noncited violation were identified.

6. Event Follow-up (62703, 92701,93702)

a. Pressurizer Power Operated Relief Valve (PORV) Inadvertent Actuation

Two primary power operated relief valves are adjusted to open at 440 psig and 490 psig, respectively, to provide overpressure protection for the reactor coolant system during low temperature, low pressure operation. Due to the potential of damage to the reactor coolant system (RCS) caused by an overpressure transient while the RCS is at low temperature, Technical Specification 3.4.9.3.c requires licensees submit a Special Report to the Commission if a transient occurs that describes the circumstances initiating the transient, the effect of the transient and any corrective action to prevent recurrence.

At 10:10 am on March 27, 1991, Trojan was in Mode 5, Cold Shutdown. The RCS was at 300 psig, water solid and approximately 122 degrees F. The greatest differential temperature between steam generators and the RCS was 40 degrees F. Licensed operators started the A Reactor Coolant Pump (RCP) to support RCS forced oxidation. Immediately RCS pressure started to increase. As a result, the solid plant watch attempted to adjust RCS letdown to control the pressure transient; however, he misadjusted the controller and the rate of RCS pressurization increased slightly. The solid plant watch rapidly recognized his error and immediately readjusted the letdown controller. Approximately 50 seconds after the A RCP was started, PORV 455A opened at 440 psig for approximately 2.2 seconds. All plant systems responded normally during and following this event.

The licensee documented their event investigation in corrective action report (CAR) 91-0147. The licensee concluded the cause of the event was incorrect implementation of a design basis analysis. The licensee noted that the lack of adequate RCS loop temperature indication contributed to this event.

NRC Generic Letter 90-06, required licensees to respond to the generic issues of "Power Operated Relief Valve and Block Valve Reliability and Additional Low-Temperature Overpressure Protection for Light-Water Reactors." In response to the generic letter, PGE contracted Westinghouse to evaluate the Trojan response to expected

transients during low temperature operation. The Westinghouse June 1990 analysis identified that if a RCP was started with the RCS solid at 160 degrees F., one or more PORVs would be required to mitigate the RCS pressure transient. The results of this analysis were not incorporated into procedural changes.

To prevent further recurrence of this type of event, the licensee changed procedures to prevent starting RCPs with the RCS completely water solid. Based on the proper operation of the PORVs and the Westinghouse analysis, the licensee concluded the transient resulted in no damage or detrimental effects to the RCS.

As followup for this event, the resident inspectors discussed the event with plant licensed operators and plant management, reviewed CAR 91-0144, and reviewed the June 1990 Westinghouse analysis. The inspectors concluded the licensee's evaluation of the event was timely, thorough and accurate. The inspectors noted Trojan licensed operators followed plant procedures leading up to and during the event. The inspectors concluded the licensee's corrective actions should prevent the recurrence of this specific type of event.

b. Containment Electrical Penetration Assemblies (EPAs)

On March 30, 1991, while in Mode 5 conducting local leak rate testing (LLRT) required by Trojan Technical Specification 4.6.1.2.d., electrical penetration assembly NZ02 experienced excessive leakage (91,020 ± 2405 standard cubic centimeters per minute). The licensee reported the event per 10 CFR 50.72 reporting requirements.

Due to the potential safety significance of this event and a 1987 failure of an EPA LLRT, the licensee formed an event review team to determine the cause of this failure. The licensee generated corrective action request (CAR) 91-0163 to document the review. The LLRT appeared to have failed due to the EPA cup seals failing.

The resident inspectors attended an ERT meeting, observed the failed seal and discussed the failure with licensee management. The inspectors learned the ERT initially concluded the seal, which had been installed during original construction, failed due to experiencing a compression set that should be expected during normal aging. The seal had originally been qualified to last for 40 years. Subsequent PGE evaluation by the licensee Equipment Qualification group and the Plant Review Board determined the seals may not last 40 years and, therefore, should be replaced. At the conclusion of the inspection period, the licensee was replacing the seals with a seal made from a different material, developing a test to qualify the seals and assessing the safety significance of the seal failure.

An NRC inspection to evaluate the original equipment qualification and subsequent events with respect to the EPA, is planned for the week of July 8, 1991.

c. Steam Generator Tube Eddy Current Inspection

During the 1989 Refueling Outage while conducting steam generator tube inspections, the licensee identified circumferential cracking of a limited number of tubes in the area of the tube support plate. Subsequently, PGE determined the cracking resulted from an explosive expansion process (WEXTEx) used by Westinghouse during the construction of the steam generators. Additionally, the licensee found the rate of axial cracking in the vicinity of the steam generator tube support plates increased. As a result of these findings, the licensee increased the surveillance of the steam generators to include all tubes for the next several refueling outages.

The 1991 Refueling Outage steam generator tube inspections found very little progression of failures due to circumferential cracking. Fourteen tubes were plugged due to circumferential cracking. However, the licensee found that the axial cracking at the tube support plates progressed significantly. A total of two hundred ninety seven tubes were plugged due to axial cracking.

As a result of the plugging of steam generator tubes during the 1991 Refueling Outage, the C and D steam generators are near the 11.5% plugging limit, C with 10.8% plugged, and D with 11.3% plugged. The licensee is developing a strategic plan to evaluate steam generator issues. The licensee is evaluating the accelerated axial cracking of the SG tubes to determine the cause. During the outage, a steam generator tube was removed for NDE examination to aid the licensee in determining the cause of the cracking. Additionally, the licensee met with industry steam generator chemistry experts. To date, the licensee's theory as to the cause for the accelerated axial cracking of the steam generator tubes at the support plates is a combination of increasing steam generator water pH in 1987 and a concentration imbalance between SG water cations and anions. The licensee is considering revising the secondary steam generator water chemistry program prior to reactor restart.

d. Inappropriate Filling of the D Steam Generator

The inspector, in addition to following up of steam generator tube inspection results, performed event followup of control operators inappropriately filling the D steam generator.

At approximately 3:36 am on May 16, 1991, plant operators began filling the secondary side of the D steam generator. At 3:47 am, the filling of the generator was stopped when operators recognized the acceptance of the welds of two steam generator tube plugs was not completed. At 4:24 am, water was noted leaking from one of the two plugs.

NRC followup inspection found that inadequate administrative controls, such as clearances or safety related outage work sheets, existed to prevent inadvertent filling of the steam generator. The inspector also found incomplete communications between the outage

shift manager, the shift supervisor and the control operator contributed significantly to the event.

The licensee evaluated this event per corrective action request (CAR) C91-G403. This CAR implemented the necessary corrective actions to prevent event recurrence.

e. Inoperability of Both Emergency Diesel Generators (EDGs)

On May 14, 1991, MR 90-1260, "Troubleshoot Ground in the JQ-2083 Power Circuit," was added to the daily work plan to provide adequate work load for electrical craftsmen. On May 15, 1991, the Trojan facility was in Mode 6, Refueling with the reactor defueled. Trojan Technical Specification 3.8.1.2.b requires one EDG operable while in Mode 6. The A EDG was operable, thereby fulfilling TS 3.8.1.1.b requirements. The B EDG was inoperable due to the B service water system (SWS) being out-of-service for annual repairs.

At 10:17 am on May 15, the A EDG day tank low level alarm activated in the control room. The control operator immediately had craftsmen discontinue work on power supply JQ-2083. JQ-2083 supplies power to various A EDG instruments. With the fuses pulled the A EDG was inoperable. At 10:20 am, the craftsmen attempted to restore power to the instrument by re-installing the power supply's fuses, but due to finding the fuse holder faulty, could not. The fuse holder was replaced, the fuses reinstalled, and power restored at 11:18 am, making the A EDG operable. The control operator complied with TS 3.8.1.2 action by immediately restoring the A EDG to service. The licensee initiated C91-0391 to investigate the event.

Licensee evaluation of the event concluded the root cause of the event was that the planner failed to identify all the instruments and interlocks impacted by the work. Additional contributing causes for the event were inadequate reviews and improper processing of a work request. As corrective actions, two lesson learned memorandums, to clarify requirements, were issued to appropriate work groups.

The inspector discussed the event with selected plant managers and supervisors, and reviewed the corrective action request. While the licensee's evaluation identified the causes of this event, the inspector concluded the licensee's evaluation did not identify a significant contributing cause to the event. Communication between the maintenance craft supervisor and the scheduling organization was insufficient to ensure daily work loads were adequately forecasted. The inspector discussed this cause with the manager of Planning and Control.

f. Drain Backup in Containment

On June 11, 1991, parts of the 45 foot elevation of containment were contaminated by water backing up from the floor drains. The majority of the water came from the Reactor Coolant Pump (RCP) seals designed leakoff. Since June 7, 1991, containment sump pumps were

tagged out to support maintenance on the electrical penetration assemblies. The Operations Department was told that the sump pumps would be energized as a result of implementing a Temporary Modification (TM) that day. The electricians who were installing the TM were told not to install the TM due to testing on the D RCP. The electricians were not told to start work on the TM and were not aware of the high priority to get power to the sump pumps.

On June 10, 1991, the Operations Department realized that the clearance for these pumps had not be signed on to. They then pursued the issue and the electricians installed the TM that night. By 4:00 a.m. on June 11, 1991, the TM was installed, but not post installation tested. By 6:00 a.m. the drains had backed up. Plant operators determined that they could check the rotation of the pump by starting the pump. The pump was started and the water was removed.

The inspector reviewed the contamination survey map and estimated that greater than 200 square feet of the 45 foot level of containment was contaminated. The Radiation Protection Department determined that the levels of surface contamination were low and initiated an immediate cleanup of the floor.

No violations or deviations were identified.

#### 7. Temporary Modifications

Temporary Modifications (TMs) are minor, temporary changes to plant equipment that do not conform with approved drawings or other design documents. These modifications are intended to be non-permanent changes of short duration. Since these are modifications to equipment, they receive independent technical review, Quality Assurance (QA) review, and Plant Manager Approval. Temporary Modifications include:

- Lifted Leads
- Electrical or Mechanical Jumpers
- Pulled Circuit Cards
- Disabled Annunciator Alarms
- Installed/Removed blank flanges
- Disabled Relief or Safety Valves
- Temporary Setpoint Changes
- Temporary supports, enclosures, or other structures attached to permanent equipment

The licensee's program for managing TMs is specified in Administrative Order (AO) 5-8, "Temporary Modifications." A previous NRC review of the Trojan TM program was documented in inspection report 50-344/90-02. At that time the licensee was issued a severity level V violation for three examples of failing to follow requirements of AO 5-8. The problems identified at that time were TM reviews exceeding the time requirements, using "White Out" on a QA record, and not removing TM tags. During the current inspection one example of failure to remove TM tags (Paragraph 4) and four examples of incomplete or improperly documented

TMs were identified. In addition at least two TMs had gone more than the required review time without review.

a. Age of Temporary Modifications

The inspector examined the age and status of outstanding TMs. In 1990 the licensee implemented a TM reduction program to reduce the number and age of TMs. The stated goals were less than 40 TMs by the end of 1990 and less than 30 TMs by the end of 1991, with less than 15 TMs older than 6 months. The licensee appears to be making improvements since there were 39 outstanding TMs at the end of 1990. However, the average age of the TMs was not decreased at that time, and twenty additional TMs have been added due to the current outage. The Branch Manager of System Engineering stated procedure changes were made to manage long term minor modifications through a different process.

b. Temporary Modification Records

PGE Quality Assurance (QA) records are required to have the words "QA Record When Completed" written at the top of the record. The inspector questioned why the current revision of AO 5-8 had been changed and did not state that the TM Log Index Sheet (log) was a QA record or that the log sheet should be marked as a QA record. This is an apparent violation (50-344/91-17-01). Licensee personnel stated that they would evaluate the situation and determine the need for the log to be a QA record.

c. Temporary Modification Safety Reviews

AO 5-8 requires three periodic reviews of TMs; (1) monthly status review by the Plant Systems Engineer (PSE), (2) once a year status review by operations, and (3) once a year validity review of each TM by the PSE cognizant engineer. The monthly reviews of TMs by the system engineer and yearly reviews by operations are required to be documented on the TM Log Index Sheet. The yearly TM review by the PSE is required to be documented on a form (Attachment 4) from AO 5-8. The inspector found four problems with these reviews.

The once a year PSE validity reviews of TMs 89-052 "C-41 Noise Suppression" (for radiation monitor power supplies) and 89-078 "Subcooling Margin Monitor Thermocouple Exchange" were late by 69 and 109 days respectively. The reviews were completed on January 30, 1991, after licensee operations and engineering personnel identified that the once a year reviews had not been performed on time.

The once a year PSE validity review of TM 88-080 "Removal of SV-3715A" (CCW make up pump tell-tale drain valve) was done by the previous PSE Engineer on August 2, 1990 (approximately 25 days late) but had not been reviewed or completed by management. After the inspector questioned the Manager of Plant Systems Engineering regarding the status of this review, it was found in the current PSE Engineer's in basket.

The monthly PGE review for March was not documented on the TM Log Index sheet. This is an apparent violation (50-344/91-17-01). The review was documented in a personal log.

The Operations yearly reviews for 1989 and 1990 were not documented on the TM Log Index sheet. This is an apparent violation (50-344/91-17-01). A 1989 Operations review to meet AO 5-8 was completed, but it was only documented in operations records. A 1990 review was conducted and documented for the start-up in 1990 independent of AO 5-8 requirements. In a discussion with the NRC Resident Inspector the Operations Branch Manager stated no system existed to prompt the annual review by the Operations Department, but one would be developed. Additionally, the Operations Branch Manager also directed the 1991 TM review be performed.

These documentation problems do not appear to be safety significant. However, in view of the fact that TM reviews and documentation had been the subject of enforcement in 1990 it appears that previous corrective actions should have prevented these errors from occurring.

d. Handling of District Corrective Action Reports

As described above, the inspector found that the licensee's TM engineer had identified that three once a year TM reviews were overdue. He also found one review which had not been signed. The engineer identified these problems on January 10, 1991 and initiated Corrective Action Requests (CARs) on these two items. In discussions with his management, he was told that these problems would be handled internally. The requirements of Nuclear Division Procedure (NDP) 600-0, revision 4 (applicable at that time) stated that the supervisor should document that the issue was to be handled internally, and turn in the CAR to QA. This was not performed. Also, no effective action was performed to assure that the review was completed for TM 88-080. Failure to correctly process those CARs is an apparent violation of the licensee's procedure (50-344/91-17-02).

Two apparent violations were identified.

8. Followup of Open and Unresolved Items (92701)

Followup Item 50-344/91-03-01, (Closed), "Failure to Adequately Review an Engineering Calculation" This followup item concerned the incorrect volume versus level curve for the Reactor Coolant Drain Tank (RCDT) and pressurizer. The errors in the RCDT volume included an incorrect level span and the total volume of the tank was about 5 gallons off (351.8 vice 347). These levels are used to calculate Reactor Coolant System (RCS) leakage. The inaccuracies in RCDT and pressurizer level were included in Periodic Operating Test (POT) 1-3, and the computer program that calculates RCS leakage. The inspector assessed the licensee's corrective actions for this error.

The licensee implemented Plant Setpoint Change 91-005 to correct the level span error. The span was changing to 32.0 inches. Nuclear Plant Engineering recalculated the volume of the tank (Calculation TM-458) for volume versus level. The licensee also deleted the pressurizer level versus volume curve and revised the RCDT volume versus level curves in the Control Room Operators Curves and Tables Reference Manual (CROCTRM).

The licensee's calculations for pressurizer level indicated that a 1% change in pressurizer level is now 125.61 gallons, instead of the 124.24 gallons used previously.

The licensee will revise the surveillance procedure and the computer program with the revised parameters prior to entry into Mode 4 from the present outage. Based on the licensee's actions to evaluate this item, this item is closed.

Unresolved Item 50-344/91-01-09, (Closed), "Energized 460 Volt cable in "B" Train Switchgear and Cable Spreading Room (CSR)" This unresolved item was identified during the Appendix R inspection documented in NRC inspection report 50-344/91-01. An NRC inspector identified that an energized cable, which was used to supply power to a welding machine, ran from the B switchgear room to the cable spreading room. This cable was "foamed" through the ceiling/floor boundary and was still plugged into the welding receptacle in the B switchgear room. Review of the applicable requirements by the inspector indicated that the installation did not violate electrical separation criteria or circuit protection. However, the cable was installed inappropriately since no evaluation was performed to assess its safety significance. Administrative Order (AO) 5-8, "Temporary Modifications," can provide administrative controls (e.g. evaluations) for temporary items, including temporary power supplies.

A temporary modification undergoes safety reviews to evaluate the effect on installed, safety-related plant equipment. The welding cable was installed for welding in the control room to implement Request for Design Change (RDC) 86-10 for the new annunciator system. Maintenance Request (MR) 88-1702 was initiated to remove the temporary power supplies between the CSR and control room. The weld cable was left installed from the switchgear room to assist with other work in progress, and not removed after this work was completed.

The requirements of AO 5-8 defines temporary power supplies as one kind of temporary modification. AO 5-8 has specific requirements for installing a temporary modification. Installing a temporary power supply without implementing the requirements of AO 5-8 is an apparent violation. As corrective actions the licensee removed the power cord and counselled appropriate personnel. Licensee actions previously discussed in Paragraph 4, in addition to those mentioned here, should prevent recurrence of this type event. The violation is not being cited because the criteria specified in Section V.A. of the Enforcement Policy were satisfied.

One noncited violation was identified.

9. Followup of Temporary Instructions (25505)

TI 2515/105, (Open), "Inspection of Licensee Activities in Reference to Bulletin 88-04, Potential Safety-Related Pump Loss." This Temporary Instruction (TI) was issued to verify the satisfactory implementation of NRC Bulletin (NRCB) 88-04. The Bulletin (issued May 5, 1988) requested that licensees investigate and correct two possible miniflow design concerns. These concerns were (1) the possibility of dead-heading one or more pumps in systems with a common miniflow recirculation line and (2) whether the flow capacity of the installed miniflow recirculation line was adequate. These concerns were also referenced in Information Notice (IN) 87-59, "Potential RHR Pump Loss," dated November 17, 1987.

The evaluation was performed on April 24, 1989, with corrective actions to be completed as part of Action Plan 89-005, "Safety Related Pump Minimum Flow."

The licensee submitted undated responses (on March 20 and April 30, 1991) to this bulletin. These responses indicated that testing for interaction of the RHR pumps indicated that there was interaction, but the flow through the weaker pump (A) was still acceptable. In the last response, the licensee stated that a design change (additional check valves) to resolve this RHR pump interaction would be performed by the 1993 outage. Due to the repair of the "B" RHR pump during this outage, it became significantly stronger than the "A" pump. A test performed (see section 5) indicated that the "A" pump will now run dead-headed, with both pumps on miniflow. The licensee stated that they are going to install a check valve this outage in the "A" RHR train to resolve this problem.

This bulletin will remain open until this check valve is installed. The other items remaining with this bulletin will be addressed at that time.

No violations or deviations were identified.

10. Outage Modifications (37700, 62703)Containment Recirculation Sump Upgraded (RDC 89-014)

As documented in inspection report 50-344/91-12, the inspector continued to question part of the design associated with the Containment Recirculation Sump. The outstanding questions included:

- o Review the evaluation of the sump bolts holding the fine mesh screens which were (1) encrusted with boric acid, and (2) lacked full thread engagement.
- o Review the evaluation of issues with the fabric (BISCO) used around the pipes penetrating the sump, to prevent debris intrusion. Some pipe operating temperatures appeared beyond the use range for the material. The effects of radiation on the material when operating and the temperature of the BISCO due to heat transfer from bare pipes or insulation did not appear to have been considered.

The inspector discussed the issue of the bolts with Nuclear Plant Engineering (NPE). NPE evaluated the bolts, and stated that the boric acid had little effect on the bolts. The lack of full thread engagement was evaluated, and did not impair the design of the sump due to the low forces expected on these bolts.

The BISCO fabric was determined to be acceptable for use in temperatures above 400 degrees F. The plant also has requirements that material not touch stainless steel piping above 200 degrees F.

The inspector asked for the temperatures of the pipes penetrating the sump. After obtaining this information, the inspector walked down the sump penetrations. The inspector noted various discrepancies, in that some fabric appeared to be touching the pipe metal that had temperatures above 200 degrees F, and also above 400 degrees F. Further, some of the BISCO fabric appeared close to the letdown line, which has a high radiation field surrounding it during plant operation. Further, some of the BISCO did not touch the letdown line, but surrounded it at a distance of about 6 inches. This line is hot during normal operations (greater than 550 degrees F), and the inspector questioned if this would be beyond the use range of the fabric.

The licensee reviewed their list of pipe temperatures provided to the inspector. The licensee determined that design rating temperatures were provided, not expected operating temperatures. A review of the expected operating temperatures revealed that the pipes in question should only see a maximum temperature of approximately 350 degrees F.

Further review of the pipes above 200 degrees F which appeared to be in contact with the BISCO fabric revealed that there was an intervening sheet metal between the fabric and the pipe. Therefore, no fabric was touching the pipe.

The inspector questioned the licensee as to the effect of radiation dose on the BISCO fabric from the letdown line. The licensee performed the calculation, and it revealed that the 25 year radiation dose to the fabric was far less than the manufacturer's rating.

The temperature for the BISCO surrounding the hot pipe was approximately 265 degrees F, below the manufacturer's use range. Based on discussions with the licensee, these issues are closed.

No violations or deviations were identified.

#### 11. Followup of Items of Noncompliance (92702)

Enforcement Item 50-344/91-03-02, (Closed), "Noncompliance with Nuclear Division Procedure (NDP) 600-0, Corrective Action Program." This violation identified the licensee's noncompliance with NDP 600-0 in that a replacement bolt for a jacket water cooling system expansion bellows was incorrectly designated as "rework" vice "modify" as the bolt was of a different strength and material. The licensee, in their April 12, 1991, reply to the Notice of Violation, concluded the cause of the violation was personnel error in that a nonconforming condition was not properly

classified. As corrective actions, the licensee obtained vendor drawings for the expansion joints, replaced and/or returned the expansion bellow bolts to their original design configuration, revised NDP 600-0 and issued a "Lessons Learned" memorandum. Additionally, by July 15, 1991, the licensee committed to sample other NCRs, classified as rework, to determine if other nonconforming material conditions exist.

The inspectors verified that the licensee's corrective actions were completed and that both emergency diesel generators' jacket water cooling system expansion bellows were returned to their original design configuration. The inspectors had no further questions on this matter.

Enforcement Item 50-344/91-03-03, (Closed), "Noncompliance with NDP 100-5, Preparation of Safety Evaluation Required by 10 CFR 50 and Trojan Technical Specifications." This violation identified the licensee's noncompliance with NDP 100-5 in that a timely safety evaluation was not performed when required. The licensee concluded in their April 12, 1991, reply to the Notice of Violation, the cause of the violation was personnel error in that the cognizant engineers failed to identify the EDG expansion bellows were not installed in a configuration consistent with the manufacturer's recommendations. As corrective actions, the licensee performed a safety evaluation that concluded the EDG was operable, revised the Trojan policy on performing operability determinations and safety evaluations, replaced and/or returned the expansion bellows to their design configurations and revised Trojan Plant Procedure (TPP) 13-1, "Operability Determinations."

The inspectors verified the licensee completed their proposed corrective actions. The inspectors had no further questions on this matter.

Enforcement Item 50-344/91-03-04, (Closed), "Failure to Document a Nonconforming Condition on a Corrective Action Request" This violation was issued for not initiating a Corrective Action Request (CAR) for an event which was a nonconforming condition. The identified condition was freezing of some sensing lines on instruments which fed into the Engineered Safety Features Actuation System (ESFAS) and Reactor Protection System (RPS).

Inspector review of this issue indicated that the heat tracing was installed under a non-quality related maintenance request in 1979, as a temporary installation, without design reviews. A walkdown of the heat tracing around these lines indicated a degraded status.

The licensee agreed with the violation and determined the root cause was personnel error. Operations management reiterated that CARs need to be initiated when appropriate. Each shift supervisor reviewed the conditions requiring a CAR (Attachment E of Nuclear Division Procedure (NDP) 600-0) with their crew.

The inspector verified with several crews that this review had been done. The specific problem with the heat tracing is scheduled to be resolved prior to next winter. The licensee now has a procedure in place to prevent this sort of temporary modification from recurring. Based on the licensee's action, this item is closed.

No violations or deviations were identified.

12. Follow-up of Licensee Event Reports (LERs) [90712, 92700, and 92701]

LER 50-344/91-02, Revision 0, (Closed), "Incore Instrumentation System Thimble Tube Leak During Power Operation." This LER described the licensee's discovery, while Trojan was at 100% power, of a leaking incore instrument thimble tube. The licensee has not yet determined the cause of the thimble tube failure. As described in NRC inspection report 50-344/91-03, thirty-two of fifty-eight thimble tubes were replaced during the 1990 Trojan Refueling Outage. These thimble tubes were replaced due to the installed thimble tubes experiencing wall thinning. The replacement tubes were slightly larger in diameter. To aid in determining the cause of the tube failure, the licensee is having Westinghouse nondestructively examine a failed thimble tube. To evaluate the extent of the wall thinning, the licensee, during the 1991 Refueling Outage, performed eddy current examination of the operable fifty-six thimble tubes. The examination identified wear rates for five of the larger diameter thimble tubes higher than for wear rates of the smaller diameter thimble tubes. Generally, the greatest wall-thinning occurred in the area where the thimble tube entered the fuel assembly bottom nozzle. To prevent continued wear at the same location on the thimble tube, the licensee repositioned seventeen thimble tubes. Two thimble tube locations remained isolated due to their removal for examination.

Resident inspector followup consisted of responding to the event, attending the event critique and reviewing the eddy current measurements of the thimble tubes. The inspector found that the greatest wall thinning rates were in areas previously determined to have high wall thinning rates. Previously, the licensee under consultation with Westinghouse, determined the acceptable minimal percent of wall thickness for a thimble tube was 65%. Since then, based on Westinghouse findings, the licensee intends to consider changing the criteria to 80%. Using the 65% through wall wear criteria, the licensee determined that the repositioned thimble tubes could safely be used until the 1992 Refueling Outage, which is planned for late March 1992. The licensee is considering sleeving the core plate to prevent further wear with incore instrument thimble tubes.

LER 50-344/91-04, Revision 0, (Closed), "Inadequate Drawings Result in Development of Inadequate Work Instructions and Lead to Inappropriate Jumper Placement and Reactor Trip." This LER described an automatic reactor shutdown that resulted from the incorrect placement of an electrical jumper. The licensee concluded the cause of the event was inadequate drawings that resulted in the planners and craftsmen not properly planning or performing maintenance. The licensee implemented the following corrective actions to prevent event recurrence: revise procedures to require work planners to designate termination points, revise procedures to better explain peer verifications, and discuss the event with the electrical craftsmen and supervisors.

Initial NRC inspection associated with this event was documented in report 50-344/91-07. Followup inspection for this LER noted that the licensee's corrective actions did not address the root cause of the

event, the unavailability of drawings. In discussing the corrective actions with the licensee representatives, the licensee stated that when drawings were not available, additional maintenance supervision or administrative controls would be implemented by the maintenance work instructions. This LER is closed based on licensee completed and proposed corrective actions.

LER 50-344/91-05, Revision 0, (Closed), "Inadequate Procedures and Failure to Specifically Identify Conditional Surveillances Results in Improper Performance of Reactor Trip System Channel Functional Tests." This LER described the licensee identified noncompliance with Technical Specification 4.3.1.1 that requires the low power setpoint for the power range nuclear instruments be calibrated and channel checked when below the P-10 setpoint and if the channel functional test had not been performed in the previous 31 days. The licensee concluded the cause of the event was the failure to identify the power range low setpoint as a conditional surveillance during a recent review. The licensee implemented the following corrective actions to prevent event recurrence: created a separate procedure to test the power range low setpoint reactor trip, revised general operating instructions to identify the requirements to perform that procedure and will review the adequacy of all procedures for conditional surveillances by September 30, 1992. The licensee concluded the safety significance of this event was minimal since the as found setpoint was within the tolerance required by the technical specifications.

As a result of further review initiated by this event, the licensee also identified the surveillance that requires a Channel Functional Test for the Turbine Trip generated from a Reactor Trip was not being performed. The licensee concluded the cause of this missed surveillance was the failure to properly interpret the surveillance requirements. As corrective actions, the licensee revised procedures so that the surveillance would be performed as required. The licensee concluded the safety significance of this event was minimal.

The inspector also discussed with licensee managers, the time table for completing surveillance program improvements. Based on licensee completed and proposed corrective actions, this LER is closed.

No violations or deviations were identified.

13. 1991 Refueling Outage Implementation (62700, 71707)

NRC Inspection Report 50-344/91-07 documented inspection associated with PGE preparations for the 1991 Refueling Outage. The inspection documented in this report is a conclusion of that effort. This inspection focused on the implementation of the outage schedule, the impact of late work package planning, and the maintenance addition/deferral process used during the outage.

The inspectors found that the implementation of the 1991 Refueling Outage schedule was generally acceptable; however, the original definition of outage scope was poor. Original outage scope contained twenty-eight hundred maintenance requests (MRs). By May 29, 1991, approximately 1600

MRs were added to the outage. The inspector evaluated a random representative sample of 200 of the 1600 MRs added to the outage scope. The inspector's review of these MRs found the following: approximately 30% of the MRs were added due to licensee personnel identifying additional deficiencies as a result of inspections or growth from work already in progress; approximately 30% of the MRs were preventive maintenance (PM) tasks that should have been included in the original outage scope but were missed by oversight; approximately 10% were PM tasks that were once in the outage scope but removed accidentally; and 30% of the MRs were tasks necessary to begin work that was previously included in the outage scope (referred to the licensee as daughter MRs).

Based on this sampling and discussions with the Manager of Planning and Control, the inspector concluded the scheduling group's knowledge of the administration of the PM program warrants strengthening, the expectations for work package identification by the work groups warrant strengthening, and the quality of planning and control scope reviews warrant strengthening.

The inspectors found the licensee's management of outage maintenance addition/deferral process was generally very good. As of May 20, 1991, forty-nine MRs had been deferred from and sixteen hundred MRs had been added to the scope of 1991 Refueling Outage. A review of the deferred items found that a high percentage of these items were removed from the outage scope due to the unavailability of spare parts. The inspector found these parts were generally not available because they were either not ordered with sufficient lead time or not effectively tracked through the maintenance procurement process. The inspector randomly sampled ten of the deferred items and concluded their deferral had no impact on plant operational safety. The deferral of approximately fifty items represented significant improvement from the 1990 Refueling Outage deferral of approximately seven hundred fifty MRs. By limiting the deferrals, the licensee substantially reduced the backlog of outage maintenance requests and improved the availability and reliability of plant safety systems.

The inspector found that the late planning of work packages significantly complicated the day-to-day planning of the outage. Because only 65% of the packages were available at the start of the outage and the plant was not originally shutdown as the Outage schedule assumed, the planning for each 3 day period had to be significantly rearranged from the original plan. Generally, Outage Management performed these changes acceptably. The affects of the late planning resulted in last minute changes to the daily schedules and an undue and excessive burden on the operating crew to review the changes.

No violations or deviations were identified.

#### 14. Exit Interview (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 on June 21, 1991, and with licensee management throughout the inspection period. In these meetings the inspectors summarized the scope and findings of the inspection activities.