UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-348/96-02 and 50-364/96-02

Licensee: Southern Nuclear Operating Company, Inc.
P.O. Box 1295
Birmingham, AL 35201-1295

Docket Nos.: 50-348 and 50-364 License Nos.: NPF-2 and NPF-8

Facility Name: Farley Nuclear Plant, Units 1 and 2

Inspection Conducted: February 4 through March 16, 1996

Lead Inspector: FOR R. W. Wright 4/11/96
T. M. Ross, Senior Resident Inspector Date Signed

Inspectors: M. A. Scott, Resident Inspector
J. H. Bartley, Resident Inspector
P. J. Kellogg, Senior Project Manager (Region II)
W. R. Crowley, Reactor Inspector
G. F. Maxwell, Senior Resident Inspector - McGuire
W. P. Kleinsorge, Reactor Inspector
G. A. Walton, Reactor Inspector
H. L. Whitener, Reactor Inspector

Approved by: P H Skinner 4/12/96
P. H. Skinner, Chief Date Signed
Reactor Projects Branch 2
Division of Reactor Projects

SUMMARY

Scope:

Routine inspections by the resident inspectors were conducted onsite in the functional areas of plant operations, maintenance and surveillance, engineering and technical support, and plant support. These inspections included a review of nonroutine events and a follow-up of previous inspection findings. Backshift inspections were conducted on February 4, 12, 13, 14, 15, 17, 19, 26, 27, and 29, and March 5, 7, 10, and 13, 1996. Onsite inspections by Region II inspectors were also conducted in the areas of operations, maintenance (especially on the secondary side), surveillance, quality assurance audits, and the root cause program.

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Results:

Plant Operations

Operations personnel and management maintained good control over routine full power operation of both units, unit 1 in particular continued to operate well (Section 2.1). Shift operators remained attentive to changing plant conditions, and were very knowledgeable of plant status and ongoing activities (Section 2.0). Operator responses to the numerous challenges and transients were exemplary (Sections 2.7 - 2.12). Problems with the electro-hydraulic control (EHC) system continues to disrupt Unit 2 operations (Sections 2.10 and 2.11). Overall housekeeping and physical conditions of the plant remained adequate (Section 2.2). Although, puddles of condensation on the floors and on/near various equipment/hardware throughout the plant is still a problem (Section 2.5). The licensee has implemented a very effective audit/incident investigation program (Section 2.13). Formal root cause efforts and broadness reviews are well done and provided positive recommendations for preventing recurring problems. Corrective actions in reducing the number of procedural inadequacies seem to be effective.

Maintenance

Maintenance and surveillance test activities were regularly performed in accordance with work order instructions, associated procedures, and applicable clearance controls. Safety-related maintenance and testing evolutions were well planned and executed (Section 3.1). For the most part, so were nonsafety-related maintenance activities. Work practices used on the secondary side were generally of good quality (Section 3.2). Responsible personnel demonstrated familiarity with administrative and radiological controls. Surveillance tests of safety-related equipment were almost always performed in a deliberate step-by-step manner by knowledgeable plant personnel in close communication with the control room (Section 3.3). Overall, craftsmen and technicians appeared well qualified and trained for the tasks they performed. Coordination and execution of repairs to the 2AC Rod Control Power Cabinet, and the planning and implementation of Hot Shutdown Panel testing were excellent (Sections 3.1.g. and 3.3.c). However, certain weaknesses were identified regarding poor pre-job preparation for the preventative maintenance of the #1 Fire Pump Diesel and multiple examples of inattention to detail during the conduct of nonsafety-related maintenance (Sections 3.3.a. and 3.2). Balance of plant (BOP) equipment failures, especially those related to the EHC system, continue to occur, directly affecting plant operation (Section 3.2).

Engineering

Overall engineering and technical support of operations, maintenance, modification, and surveillance activities was good. However, computational errors by Southern Company Services directly resulted in a serious steam leak due to inadequate bolt torque on a drain tank manway (Section 4.1). Onsite engineering continued to interface well with the corporate office, and maintained a consistently proactive posture in addressing evolving plant issues as exemplified by the Engineering Projects Council (Section 4.2). The licensee instituted a study of the secondary side of the plant to identify all single point failure vulnerabilities. Actions taken based on this self-assessment initiative should improve BOP reliability and reduce continuing plant challenges (Section 3.2). The Nuclear Operations Review Board meeting held onsite was brief with little discussion (Section 4.3).

Plant Support

Health physics personnel provided good support of steady-state operations (Section 5.3). Personnel entry into the protected area was well controlled at the primary access point. Security personnel were consistently alert and implemented the site's security plan in an appropriate manner (Section 5.2). Fire protection features were adequately maintained, or adequate compensatory measures were implemented. The licensee currently plans to repair the Unit 1 containment fire detection system during the upcoming mid-cycle outage in April (Section 5.1). Resolution of the high failure rate of critical preaction sprinkler systems is also receiving considerable management attention (Section 3.3.d). The quarterly emergency plan drill with the new Operations Manager acting as Emergency Director for the first time went well (Section 5.4).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 9.

1.0 PERSONS CONTACTED

Southern Nuclear Operating Company Employees:

*Bayne W., Chemistry/Environmental Superintendent
Bell B., Electrical Maintenance Superintendent
Buck C., Technical Nuclear Manager
*Coleman R., Maintenance Manager
*Crone P., Licensed Training Supervisor
Enfinger L., Plant Administration Manager
*Esteve T., Daily and Outage Planning Supervisor
Garland H., Mechanical Maintenance Superintendent
Gates S., Team Leader - Maintenance Performance Team
*Grissette D., Operations Manager
Hillman C., Security Manager
*Hill R., General Manager - Farley Nuclear Plant
*Hornbuckle J., Safety Audit and Engineering Review Auditor
Johnson R., Instrumentation and Controls Superintendent
*Jones L., Material Supervisor
Kale J., Maintenance Engineering Support Group Supervisor
Mitchell M., Health Physics Superintendent
Monk R., Engineering Support Supervisor - Equipment Evaluation
*Myrick C., Captain - Security Force
*Nesbitt C., Assistant General Manager - Plant Support
Odom J., Superintendent Unit 1 Operations
Powell J., Superintendent Unit 2 Operations
*Stinson L., Assistant General Manager - Plant Operations
*Thomas J., Engineering Support Manager
*Yance B., Plant Modifications and Maintenance Support Manager
Vanderbye R., Emergency Preparedness Coordinator
*Warren W., Engineering Support Supervisor - Performance Review
*Waymire G., Safety Audit and Engineering Review Site Supervisor
Williams L., Training/Emergency Preparedness Manager

*Attended the exit interview

During the course of this inspection a number of other licensee employees were contacted that work for health physics, operations, technical, engineering, security, maintenance, I&C, and administrative departments.

1.1 Visiting NRC Inspectors

During the inspection period, a number of Region II inspectors conducted onsite inspections with the results of their efforts detailed in the text of this report. Each of these inspectors conducted an interim exit (see Section 8.0). The visiting inspectors were as follows:

a. Kellogg P., Region II Senior Project Manager (QA audit and root cause program inspection week of February 5);

b. Crowley B., Reactor Inspector (Maintenance/Surveillance core inspection week of February 12);

c. Maxwell G., SRI - McGuire (Operations core inspection week of February 26);

d. Kleinsorge W., Whitener H., and Walton G., Reactor Inspectors (Secondary side maintenance inspection weeks of February 26 and March 4);

2.0 PLANT OPERATIONS (40500, 71707, 92901 AND 93702)

The inspectors conducted frequent tours of the MCR to verify proper staffing, operator attentiveness, and adherence to approved procedures. The inspectors also reviewed operator logs and TS LCO tracking sheets, walked down the MCBs, and interviewed members of the operating shift crew to verify operational safety and compliance with TS. Instrument indications, trend charts and safety system lineups were periodically reviewed from control room indications to assess operability and plant conditions. The inspectors attended daily plant status meetings to maintain awareness of overall facility operations, maintenance activities and recent incidents. Morning reports and FNPIRs were reviewed on a routine basis to assure that potential safety concerns were properly reported and resolved.

During routine tours of the MCR, the inspectors regularly observed that very few MCB and EPB annunciators were in alarm at any one time for the entire control room. Of these, only one or two annunciators were in an alarm condition for any extended period. The EPB and Unit 1 MCB annunciators were frequently in a "blackboard" condition. MCB deficiencies continued to receive high level management attention and were pursued aggressively. Operator attentiveness was maintained at a high level throughout the inspection report period and response to changing plant conditions was exemplary as discussed below.

2.1 Status

Unit 1 operated continuously at full power for the entire inspection report period, except for a scheduled ramp down to 15% power on February 10 to cleanup SG chemistry. The unit was returned to 100 percent power on the 11th. Unit 1 also experienced a sudden, unexpected runback of the 1B SGFP on February 29. Operators promptly restored MFW flow with minimal impact on unit power operation.

Unit 2 operated continuously at full power for the entire inspection report period, except for several events that required ramping down the unit. On March 2, power was reduced to 88% power for less than a day to replace the Moog valve (hydraulic servo) on the #1 main turbine governor valve. On March 11, power was ramped down to 58% due to SGFP governor valve problems and work. On the next day, while preparing to ramp back up to 100% power after replacing SGFP Moog valves, the 2A SGFP experienced a large EHC fluid leak prompting operators to initiate a rapid ramp down to 22% reactor power. On March 13, after repairing the 2A SGFP EHC fluid leak, operators conducted a rapid ramp down of Unit 2 from 33% to 12% power when the 1A MSR second stage drain tank manway gasket blew out causing a large steam leak in the Turbine Building. Unit 2 was returned to full power operation on March 15.

2.2 Routine Plant and Facility Tours

General tours of FNP facilities were performed to examine the physical conditions of plant equipment and structures, and to verify that safety systems were properly aligned and activities that effect their operability were performed IAW regulatory, operating license and plant procedural requirements. These tours were performed on both dayshift and backshifts.

Limited walkdowns of a more detailed nature of the accessible portions of safety-related structures, systems and components were also performed in the following specific areas:

a. SWIS
b. Unit 1 and 2 EDGs 1-2A, 1B, 2B, 1C and 2C
c. Unit 1 and 2 MDAFW and TDAFW pump rooms
d. Unit 1 and 2 piping penetration rooms (100 and 121 ft. elev.)
e. Unit 1 and 2 electrical penetration rooms (139 ft. elev.)
f. MCR HVAC and CREVS
g. Unit 1 and 2 SWIS Battery rooms
h. Unit 1 and 2 MSR drain tanks
i. Unit 1 and 2 SFP, heat exchanger, and pump rooms
j. Unit 1 PRF room
k. Unit 2 Containment Spray pump rooms
l. Unit 1 and 2 SGFPs
m. Unit 1 MSVR
n. Unit 1 and 2 Circulating Water Pump Pits
o. Unit 1 and 2 SGBD spaces
p. Auxiliary Building HVAC and Containment Purge rooms
q. Unit 1 and 2 Charging Pump Rooms
r. Unit 1 and 2 RHR Pump and Heat Exchanger Rooms
s. Unit 1 and 2 HSDPs

In general, material conditions and housekeeping for both units were adequate. A number of minor equipment and housekeeping problems were reported to the responsible on-shift SS and/or maintenance management for resolution.

2.3 Plant Tag Orders

During the course of routine inspections, portions of the following tagorders and associated equipment clearance tags were examined by the inspectors:

- TO# 96-436-2; Unit 2 TDAFW pump
- TO# 96-443-0; Number 2 Service Water Battery

- TO# 96-490-1; Unit 1 HSDP (caution tags)

All tags and tag orders examined by the inspectors were properly implemented.

A Region II inspector conducted an evaluation of the administrative controls that the licensee has in place for "hold tags" or "caution tags". During the inspection, TS 6.8.1, FNP-0-AP-14, Safety Tagging, and FNP-0-SOP-0, General Instruction To Operations Personnel, were reviewed and referred to for requirements. The inspector evaluated the implementation of FNP-0-AP-14, Section 17.0 as it related to the use of personalized hold tags. The inspectors also evaluated the methods that the licensee uses to assure that hold and caution tags are not lost or become illegible after they have been attached to the applicable valve, switch, component, or piece of equipment.

The inspector reviewed the most recent audits that the operations staff has completed for accountability of attached tags. The inspector noted that the audits were conducted each week for tags that were attached to components or valves that are physically located outdoors. The remaining attached tags were being audited monthly. The inspector observed and verified that these audits were being conducted in accordance with the Controlling Procedure FNP-0-SOP-0, Appendix D.

The inspector interviewed supervisory personnel from the maintenance department and reviewed the logs and methods of controls that are in place for personal hold tags. The inspector determined that maintenance personnel were individually issued, for their usage, hold tags that had uniquely controlled tracking numbers. The various group supervisors, i.e. electrical, mechanical, etc., were maintaining a tracking log book to show which individuals had the controlled tags.

The inspector found that both maintenance and operations personnel were thoroughly familiar with the procedural requirements of FNP-0-AP-14. The inspector also determined that the licensee has controls in place to reduce the likelihood of incorrect usage of personalized hold tags. In addition, active tags are being tracked through an audit program by operations. Plant personnel were thoroughly familiar with the procedural requirements for safety tagging.

2.4 Technical Specification Compliance

Inspectors reviewed selected TS LCO status sheets on a regular basis in order to confirm that entries into TS Action Statements were recognized, tracked, and complied with. Responsible Operations personnel, primarily the applicable unit SFO, maintained good control of all TS LCO requirements and Action statements.

2.5 Engineered Safety Features Walkdown - Chemical And Volume Control System (Including High Head Safety Injection)

A Region II inspector found that the system lineup was consistent with the site drawings and the as-built configuration described in the FSAR. The system material conditions were evaluated to verify that:

* Hangers and supports were aligned correctly and were made up properly.
* Housekeeping was acceptable.
* Valves were installed correctly and did not have gross packing leakage, bent stems, missing handwheels, and were properly labeled.
* The adjacent areas were free from ancillary equipment, ignition sources, or flammable materials.

On February 27, the inspectors conducted a detailed walkdown of the accessible portions of the Unit 2 CVCS and selected portions of the same system for Unit 1. During the inspection, the plant FSAR Section 6.3.2.2 and Figure 6.3-1 were referenced for system design requirements and configuration. Also, Site Drawings D-275039 Sheets 1 through 6, D-175039 Sheets 1 through 5, and the Controlling Procedures for Safeguards Systems Lock Valve Verification, FNP-1/2-STP-64, were used to determine if the required system valves were locked in the desired positions. The inspector noted that various places throughout the plant had "puddles" of condensate collecting on the floors and on/near installed equipment/hardware. The inspector discussed the accumulation of this condensate with plant supervision. The inspector were informed that currently an evaluation was being conducted to determine what, if anything, should be done to try and reduce or eliminate the accumulation of the condensate throughout the plant.

The inspector observed that the valve handwheel reach rod connected to the manually operated discharge isolation valve for the 2A CVCS pump had a deficiency tag dated January 9, 1995 attached to the reach rod. The inspector discussed the valve's (2-CVC-V8485A) condition with supervision and reviewed a Work Order WO-535324 that had been written to authorize repairing the reach rod. Apparently, on January 10, 1996, the repairs had been completed but the operations staff has not returned it to service.

The inspector found that the dysfunctional condition of the valve's reach rod was classified as a "workaround". Numerous manually operated CVCS valves have dysfunctional handwheel reach rods. The inspector noted that this condition has required operators to enter the CVCS pump rooms to re-position or verify positions of the associated valves. The rooms were considered radiation areas containing radiation levels that were higher than the areas where the handwheels would normally be manipulated. The inspector observed that repeated entry into the CVCS pump rooms could effect the ability of individuals to maintain their ALARA objectives. The inspector was informed that licensee management has scheduled an evaluation team to assess the overall condition of the reach rods associated with the CVCS pump room valves.

The inspector determined the CVCS system valve lineup was consistent with controlling procedures and drawings. The valves required to be "locked" were found to be in their correct positions. Housekeeping and plant material condition was found to be acceptable.

2.6 Seismic Monitors

A Region II inspector conducted an evaluation of recent changes that the licensee has made to the site seismic monitoring system. The changes were completed during the late Fall of 1995 and involved changing: the response spectrum recorders, acceleration sensors, the triaxial peak recording accelerographs, and the use of self-contained triaxial accelerographs in the river water structure. The inspector reviewed the current revision of the FSAR Section 3.7.4 and TS Section 3.3.3.3. The inspector noted that the FSAR Section 3.7.4 has not been revised to reflect the changes that have been made to the monitoring system. Additionally, the inspector noticed that the TS Section 3.3.3.3 has been revised to delete all of the requirements for seismic instrumentation including the surveillance requirements.

The inspector evaluated the most recent periodic surveillance tests that have been completed on the new monitoring system. The inspector noted that the licensee is continuing to periodically test the system. Also, the inspector noted that these tests were conducted in accordance with procedures that were written to accommodate testing the new system.

The inspector was informed by site test personnel that the FSAR is being revised to reflect the changes that have been made to the seismic monitoring system. Also, the periodic surveillance testing of the system will continue at the frequencies that were prescribed in the previous revision of the TS Section 3.3.3.3. The followup to assure the FSAR is revised is identified as IFI 50-348, 364/96-02-01, Seismic Monitoring System FSAR Update.

2.7 Urgent Rod Control Problem

On February 4 at 0936 a.m., the licensee experienced a Unit 2 rod control system problem. Control board annunciator FF1, Rod Control System Urgent Failure, went into alarm. Unit operators responded appropriately IAW the applicable ARP, and requested I&C support. No power reduction or immediate operator actions were required. The licensee promptly informed the resident inspectors. The inspectors responded to the site to verify plant conditions and observe licensee efforts to troubleshoot the problem and effect repairs (see Section 3.1.g). After I&C replaced the failed rod control power cabinet circuit card, an inspector observed a unit operator satisfactorily perform the required PMT IAW FNP-2-STP-5.0, Full Length Control Rod Operability Test.

2.8 Unit 1 Ramp Down for SG Chemistry Control

On February 10, operators ramped Unit 1 down to 15% power to improve SG chemistry conditions by allowing impurities to return from hideout and flushing them out at the maximum blowdown flowrate. Unit 1 remained in this condition for the weekend. The Moog valves on a SGFP were replaced during this period for diagnostic purposes because of the considerable EHC-related problems on Unit 2. On February 12, Unit 1 was returned to full power operation. Resident inspectors interviewed responsible operators, SS, and Operations management, reviewed operator logs and morning reports during the rampdown period, and walked down the main control boards before and after the evolution. Based on these efforts, the inspectors concluded Operations and plant systems performed well.

2.9 1B SGFP Runback

On February 29, at 12:46 p.m., with a resident inspector in the control room and Unit 1 at 100 percent power, the 1B SGFP suffered a sudden control system failure causing pump speed to run back. Simultaneous with the run back, annunciator TSLB-1, 4-5 (EC-1) "PROC CAB PWR FAILURE" became lit. The 1B SGFP run back was immediately recognized by the operators who promptly took manual control of the pump terminating the run back at about 3200 rpm. During the transient, the 1A SGFP automatically increased in speed to approximately 5000 rpm. Inorder to meet feed flow demand, the FRVs also opened up in an attempt to provide additional flow. Operators manually increased 1B SGFP speed to normal to eliminate the steam to feed flow mismatch that had occurred as a result of the run back, and restore SG water levels. MCB annunciators on the mismatch and SG levels cleared as plant conditions stabilized. Subsequent review of MCB trend recorders by the inspectors determined that feed flow had decreased from 3.8E6 lbm/hr to 2.8E6 lbm/hr by the time operators took manual control; and that SGWL had dropped from 66% to 50% on the narrow range scale before it was restored. Operators also started the third condensate pump to maintain SGFP suction pressure during the transient. Due to the operator's prompt response, plant conditions were stabilized with little or no adverse impact. Actual duration of the event was about 5 minutes. The licensee initiated DR 538716 and FNPIR 1-96-65.

With an inspector and I&C personnel present minutes after terminating the transient, operators opened power cabinet 8 to investigate the problem. Cursory inspection revealed that a 1B SGFP speed controller card had a failed operating light. A DR was generated to work the problem (see Section 3.2.e).

2.10 Unit 2 Main Turbine Governor Valves Problems

On March 1, at approximately 10:00 a.m., with Unit 2 at 100 percent power, MCB annunciator (LB-1) "DEH Trouble" went into alarm. Operators then noticed that the #1 main turbine governor valve was in a contingency mode which caused the DEHC system to switch from sequential to single valve control per design. The contingency was initiated when the #1 valve unexpectedly began to move or drift closed (off program) from the 100% to 93% full open position. When the DEHC system switched to single valve control, the three other MTG GVs automatically began to reposition towards the DEH pre-programmed 100% power single valve position (i.e., 78% full open). Immediately recognizing the situation, operators switched the DEHC system to manual stopping all valve motion without decreasing main turbine steam demand. A resident inspector observed that no reactor parameters were perturbed by review of log data, DEH system outputs, and other trend information.

A similar event occurred on January 23, 1996 (IR 95-21, Section 2.7 and FNPIR 2-96-027), when the #1 GV would not move on program with the other governor valves. As with the January event, Unit 2 was downpowered to roughly 90 percent on March 2, and the valve's EHC servo-valve (i.e., Moog valve) was replaced. In addition, for the first time since the last Unit 2 refueling outage, the licensee replaced the EHC fluid block filters for all Unit 2 MTG GVs. The 10 micron block filters are up stream of the servo valves which also have internal filters (small valve - 35 micron and large valve - 40 micron). The inspector and licensee observed that the block filter for the #1 valve had noticeable brown darkening on its filter surface. The #4 block filter had less brown debris/discoloration while the other two block filters for the other governor valves were nearly clear of debris/discoloration. The coated filters had a ferrous odor to them. The filters were sent to the servo-valve vendor for examination.

Late on March 2, the licensee changed the EHC system skid particulate and Fullers Earth filters. This was done in conjunction with the above to reduce debris in the DEH fluid system. The licensee discovered loose Fullers Earth in the bottom of the system filter cartridge holder. The licensee was investigating whether or not the personnel involved with the cartridge change out had routinely cleaned the holder. On March 4, the Moog valve vendor provided reports (under vendor repair numbers 48515-1, and 48465-1 to -8) on the nine of eleven valves removed indicating that there was brown sludge found in all of those valves' internal filters (downstream of the block filters) and various indications of excessive bypass leakage (except one) but were overall characterized as exhibiting normal wear. The details on the "as found" condition from a corporate engineer who had accompanied the nine valves to the vendor for inspection had yet to be place into the root cause report draft. The inspector discussed the initial vendor reports with the licensee, looked at removed servo-valve parts, and the brown material on the filter prior to them being sent to a laboratory to get the material on the filters analyzed. The licensee was continuing to evaluate the overall findings to resolve the EHC problems.

In summary, by the events with the # 1 governor particularly, the licensee surmised that debris was still being introduced into and/or being released to circulate in the fluid portion of the EHC system. Vendors had been appropriately tasked (and were providing feed back) to determine the nature of the debris in the system, and/or evaluate potential sources in the system, and evaluate other details of the system. Based on the knowledge thus far gained regarding the buildup of material on the filters, the licensee instituted Moog valve and block filter replacement actions as discussed in the next section.

2.11 Unit 2 Ramp Downs Due To Steam Generator Feed Pump Governor/Moog Valve Problems

At about 6:45 a.m. on March 11, the night shift UO noticed that the 2B SGFP HP governor valve was not fully closed as it should be with the unit at 100% power. The Turbine Building SO verified locally that this HP GV was partially open and controlling. At 9:00 a.m., the day shift UO noticed that the 2A SGFP HP governor valve indication for full open was no longer lit. Another Turbine Building SO confirmed locally that the 2A SGFP HP GV was also partially open. A subsequent licensee review of the plant computer trend data revealed that LP steam flow had decreased considerably over the past 24 hours, which would be indicative of the HP GVs coming open and assuming some of the demand. Although extremely unusual, the shared steam demand was not as yet adversely affecting MFW flow (FNPIR 2-96-072 was initiated). The resident inspectors also began to monitor SGFP performance from the MCR and locally at the SGFP skids. In order to stabilize the situation, Unit 2 operators slowly isolated LP steam to each SGFP and transferred total control to the HP GVs. Later that evening, Unit 2 was successfully ramped down to 58% power to replace SGFP HP and LP governor valve EHC Moog valves and in-line (block) filters.

On March 12, after all SGFP Moog valves and in-line filters had been replaced, unit operators prepared to return Unit 2 to full power operation. The 2A SGFP was online supplying total MFW flow with the unit at 59% power and the 2B SGFP offline due to low bearing lube oil pressure problems. At 11:00 a.m., the MCB EHC trouble alarm actuated and a Turbine Building SO was dispatched. A large EHC fluid leak (about three to five gpm) was identified coming from the recently replaced 2A SGFP LP GV Moog valve. Resident inspectors responded to the MCR and 2A SGFP skid. Operators promptly began a rapid ramp down of Unit 2 IAW AOP-17, Rapid Load Reduction. Within about 20 minutes, reactor power was reduced to 25%, the 2B SGFP was returned to service, and the 2A SGFP was tripped offline. Approximately 80 gallons of EHC fluid was lost from the skid reservoir before the leak could be isolated. Operator response to the transient was excellent. FNPIR 2-96-074 was initiated and maintenance personnel again replaced the Moog valve to the 2A SGFP LP GV. At 5:34 p.m., the 2A SGFP was returned to service and the 2B SGFP was taken offline. A ramp up of reactor power was commenced shortly thereafter. At 5:53 p.m., the 2A SGFP was tripped offline when it experienced another large EHC fluid leak similar to the previous one. The 2B SGFP was placed back in service and reactor power was reduced from 30% to about 22% power.

The root cause of both 2A SGFP EHC fluid leaks was determined to be a fit up problem between the LP GV Moog valve and its sheet metal housing on the pump skid. There was a slight, almost invisible physical interference that prevented the Moog valve from sitting perfectly flush. Consequently, a minuscule clearance gap existed at this critical dimension that allowed an "O" ring in one of the Moog valve EHC fluid ports to blow out. Once the interference was recognized and fixed, maintenance personnel were able to successfully reinstall another Moog valve.

2.12 Large Steam Leak In The Unit 2 Turbine Building

On the morning of March 13, while ramping up to 49% power (just after resolving the 2A SGFP EHC fluid leaks), the 1A MSR 2nd stage drain tank manway gasket blew out. Upon notification of a large steam leak in the TB from an SO stationed by the 2A SGFP, operators rapidly ramped down the unit from 33% to 12% power and secured the leak IAW AOP-17 and AOP-14, Secondary System Leakage. Resident inspectors responded to the MCR and TB to verify plant conditions were stabilized and examine any associated equipment damage. A similar event had occurred on June 25, 1995 (FNPIR 2-95-158) when the 2B MSR 2nd stage drain tank manway gasket blew out. In both instances no one got hurt and TB equipment damage was minimal; although considerable cleanup was necessary, several intermittent electrical grounds were noted, and the drain tank manway gasket had to be replaced and insulation repaired. While the licensee investigated the cause of the manway gasket failure (FNPIR 2-96-076) and effected repairs, the first and second stage steam supplies were isolated to the 1A and 1B MSRs and second stage steam was isolated to the 2A and 2B MSRs. Reactor power was increased back to 35% power and held there in accordance with UOP-3.1, Power Operation, and SOP-28.1, Turbine Generator Operation, which required placing the MSRs back in service prior to further power escalation. The licensee's investigation determined that the torque values used on the MSR 2nd stage drain tank manway bolts were not computed properly (see Section 4.1) and resulted in insufficient torque. Unit 2 operators did a exceptional job responding to the event and establishing stable plant conditions.

On March 14, after repairs were completed and the chemistry hold was lifted, inspectors observed the orderly ramp up of Unit 2 to 50% power IAW UOP-3.1 and SOP-28.1. The unit was returned to full power operation on the morning of March 15. SGFP operation, as observed by the inspectors, appeared normal.

2.13 Effectiveness of Licensee Control in Identifying, Resolving, and Preventing Problems

The resident inspectors routinely reviewed all FNPIRs initiated during the inspection period to ensure that plant incidents that effect or could potentially effect safety were properly documented and processed IAW FNP-0-AP-30, "Preparation and Processing of Incident Reports ...". The inspectors also reviewed a selected number of completed FNPIRs to determine licensee's effectiveness in: 1) identifying/describing problems; 2) elevating problems to the proper level of management; 3) conducting problem/root-cause analysis and/or derivation; 4) assessing operability and reportability; 5) developing appropriate corrective actions and 6) evaluating cause/corrective action scope for generic implications.

Overall, the inspectors concluded the licensee's program for identifying and resolving problems was effective, and being accomplished IAW AP-30. Plant personnel exhibited an appropriate threshold for identifying problems and initiating FNPIRs. Each new FNPIR initially received prompt attention and was routinely discussed by management in the next morning status/POD meeting. However, during the months of August 1995 through November 1995 the backlog of outstanding FNPIRs increased dramatically from 36 to 130. Recognizing this increase, licensee management initiated aggressive efforts to work the backlog down to more manageable levels. By the end of February 1996, the backlog was down to 44 outstanding FNPIRs. These efforts demonstrated management's ongoing sensitivity to the importance of the FNPIR program. However, a natural consequence of completing so many FNPIRs in such a short period of time is a significant increase in open FNPIR commitments and root cause recommendations. Resident inspectors will follow the issue to ensure continued management attention.

During the week of February 5, a Region II inspector independently evaluated onsite programs for incident investigations and root cause determinations. The inspector reviewed the FNPIR's generated during the last six months of 1995 to determine the cause of the decrease in the number of root cause determinations, as identified in IFI 348,364/95-20-01, Decrease in Licensee's Number of Root Cause Determinations. The FNPIR's reviewed were as follows:

1-95-151 RWST Overflowed
2-95-157 Rx Trip Due to Hi Level 2C S/G (formal root cause)
1-95-182 Control Switch for 2C D/G "B" Air Compressor Selected to OFF
2-95-186 Low Instrument Air Pressure
1-95-188 Several Clappers Failed to Trip
2-95-189 TDAFWP failed to Meet Acceptance Criteria for Speed
1-95-191 I&C Instrument Control Air Compressor Tripped
1-95-196 Clearance Declared on 1-2A D/G
2-95-197 Card CJ331 BOP Cabinet J Defective
1-95-200 Control Room Supply Fan 1A Discharge Damper Found Full Open
1-95-202 Breaker EP-11 Closing Spring Was Not Charged
1-95-205 "B" Train RWST LI4075B Failed
2-95-206 Missed Fire Watch (formal root cause)
1-95-210 NRC Generic Letter 88-14
2-95-232 2B PRF Exchanger Fan Flow Found Low After Maintenance
1-95-238 Water Clarity in Refueling Cavity Poor
2-95-268 Annunciator FF5 in Alarm
2-95-275 Channel II Delta-T Declared Inoperable
1-95-291 N35 Failed STP-41.2
1-95-296 Electrician Opened Wrong Breaker
1-95-299 1B SG Atmospheric Relief Opened, No Apparent Reason
1-95-305 HP Stop & Governor Valve Failed to Stop Steam Flow to 1A SGFP
1-95-309 Steam Flow Channel FT-474 Stayed at 0
1-95-310 Controller FK478 Input Increased to 100% "A" FRV Opened
1-95-314 Failure to Establish Fire Watch for Room 465
1-95-316 Supports on 1B Atmospheric Relief Damaged

1-95-317 1A SW Pump Upper Guide Bearing Temp 182 Degrees and Rising
1-95-318 1K MCC Breaker Tripped
2-95-339 Oil Leak on 2A Circulating Water Pump
2-95-327 Unidentified Leakage 0.5 gpm (PASS Sample Problem)
1-95-345 Failure to Perform Fire Load Transient Analysis
2-95-351 EH Pump Discharge Filters Clogged
1-95-354 1A Battery Charger Room C/R Low Delta-P Alarm Comes In

The inspector reviewed the following procedures to determine the depth and scope of the licensee's root cause determinations:

FNP-0-AP-30, March 28,1994, Revision 21, Preparation and Processing of Incident reports, Plant Event Reports & Licensee Event reports

FNP-0-ACP-9.0, Root Cause Program - dated 9/15/94

FNP-0-ACP-9.1, Root Cause Investigation - dated 3/22/94

These procedures provided the thresholds for preparing the various reports, guidelines for the content of the reports, and a thorough investigation outline for formal root cause determinations. The inspector concluded that the licensee had a well established incident reporting system. The review of the above reports indicated that the licensee was experiencing about the same number of events per year; however, the significance of the events was such that fewer formal root cause determinations were required. The data indicated the same trend noted in the SAER audits, a decrease in the number of inadequate procedures and an increase in the number of personnel errors associated with failure to follow procedures. This review provides the basis for closing IFI 50-348, 364/95-20-01 (see Section 2.14.b).

Safety Audits

The Region II inspector also reviewed selected SAER audit reports, findings, corrective action reports, and audit work sheets to evaluate the effectiveness of the licensee controls in identifying resolving, and preventing issues that degrade the quality of plant operations or safety. The following audit reports and SAER working procedures were reviewed:

95-OA/41-2	Refueling Activities
95-SAER/21-7	89-10 MOV Program
95-M&TE/5-1	M&TE - I&C
95-CCD/21-13	Control of Controlled Documents
95-FL/27-2	Fuel Reload
95-PRTP/32-2	Post Refueling Test Program
95-CAR/91-2	Corrective Actions
95-SCF/21-1	Control of Scaffolding
95-RAD/2-1	Radiation Controls
95-SEEI/36-1	FNP Operating Equipment Evaluation Program
95-SAER/21-5	Performance team Activities
95-EM/15-1	Electrical Maintenance - Routine

95-STPm/34-1	Surveillance Testing -Maintenance
95-CCD/21-4	Control of Controlled Documents
95-SAER/21-2	U-2 Shutdown & SG Flush
95-ISI/29-1 &	ISI Testing - Engineering Support
95-STPe/34-1	" " " " " " " " " " "
95-STPc/34	Chemistry, Health Physics, and Environmental STP's
95-FL/27-1	Fuel Load
95-CAR/19-1	Corrective Actions
95-SAER/21-1	Refueling Outage Activities
95-OPS/7-1 &	Plant Operations Surveillance Testing - Operations
95-STPo/31-1	" " " " " " " " " " " " " " " "
95-Pru/10-1	Procurement of Materials and Services
95-SAER/25	SAER Site Supervisor Activities
94-MC/11-1	Material Control
94-PMD/09	Plant Changes & Modifications
94-CSP/04	Control of Special Processes - Maintenance
94-QC/17	Quality Control
94-MQS/21	Safety Audit of MQS Inspection Inc.
94-SEE/1	FNP Operations experience Evaluation Program
94-CAR/19-2	Corrective Actions
94-KMTRC/21-1	Safety Audit of Kinemetrics Inc. On-site Reviews for FNP Maintenance Department
94-CHM/34	Surveillance Testing - Chemistry Department
94-MESG/1	Maintenance - Maintenance Engineering Support Group
94-RAD/2	Health Physics - Radiation Controls
94-STP/34-1	Surveillance Testing Program
94-I&C/15	Corrective & Preventive Maintenance Programs - I&C
94-I&C/34	Surveillance Testing - I&C
94-SAER WP-21	Industrial safety Outage Activities
94-SAER WP-29	Surveillance Testing - Systems Performance
& 34	" " " " " " " " " " " " " "
94-SAER WP-32	Post Refueling Test Program
94-SAER WP-27	Refueling
94-SAER WP-18	Test Control
94-SAER WP-01	Environmental Monitoring
94-SAER WP-07	Plant Operations
94-SAER WP-10	Procurement of Materials & Services
94-SAER WP-15	Maintenance - Electrical
94-SAER WP-19	Corrective Actions
94-SAER WP-27	Fuel Reloading

Selected work procedures and planning guides for the above audits were reviewed to determine the scope and depth of the audits. The inspector concluded that the audits were of appropriate depth and scope for the areas addressed. The revised planning guides required experienced auditors to conduct an effective audit. The licensee was aware of this and utilized personnel that had come from the line staffs as auditors.

Corrective Action Reports 2051 through 2179 (dated February 15, 1994 to January 30, 1996) were reviewed to determine the effectiveness of the corrective actions and the status of open corrective actions. The inspector determined that the corrective actions were appropriate.

While some recurring problems with failure to follow procedures were identified, the corrective actions were effective in preventing the recurrence of these problems.

A review of audit findings for the past year indicated that while the number of findings of inadequate procedures had decreased, the number of personnel errors in following procedures had increased by almost the same amount. These findings indicated that the licensee had been effective in correcting program problems and now faces the challenge of improving procedural adherence.

The inspector concluded that the licensee had implemented an effective audit program and that the corrective actions had been effective in reducing the number of procedural inadequacies.

2.14 Operations Followup

a. (Closed) LER 50-364/95-07, Reactor Trip Due To Turbine Trip Caused By Overfilling Of The 2C Steam Generator

The licensee determined the event was due to cognitive personnel error in that the control room personnel overcompensated feedwater flow in response to a feedwater transient. The licensee's corrective actions were to coach the individuals involved, revise the procedure to include considerations of miniflow valve operation, and include the incident in 1995 Licensed Operator Retraining. The inspectors verified the licensee's corrective actions by interviewing Operations management and reviewing Licensed Operator Retraining documentation and FNP-2-SOP-21.0, Condensate and Feedwater System, Revision 42. The inspectors determined the licensee's corrective actions were adequate and complete. This LER is closed.

b. (Closed) IFI 348,364/95-20-01, Decrease In Licensee's Number Of Root Cause Determinations

This IFI is closed based on the discussion in Section 2.13.

3.0 MAINTENANCE AND SURVEILLANCE (61726, 62700, 62703 AND 92902)

3.1 Maintenance Observation (62703)

Inspectors observed and reviewed portions of various licensee corrective and preventative maintenance activities, to determine conformance with procedures, work instructions, industry codes and standards, and regulatory requirements. Work orders were also evaluated to determine status of outstanding jobs and to ensure that proper priority was assigned to safety-related equipment. Inspectors witnessed surveillance activities performed on safety-related systems/components in order to verify that activities were performed IAW licensee procedures, FNP Technical Specifications and NRC regulatory requirements. Portions of the following maintenance activities and surveillance tests were observed:

a. WA 448942 and 448950; Emergency Diesel Generator 2B Air Start System Preventive Maintenance

These WA's covered the quarterly inspection of the 2B EDG and the PM of train "A" of the 2B EDG Air Start System, including change-out of the Dryer Desiccant. The inspectors observed portions of these activities to verify that TS, the FSAR, and the following procedures were complied with:

- FNP-O-MP-12.3, Revision 7, Diesel Engine Air Start System Quarterly Inspection

- FNP-O-MP-14.6, Revision 8, Emergency Diesel Generators 1-2A, 1B and 2B Quarterly Inspection

- FNP-O-GMP-11.0, Revision 3, General Inspection of Tanks and Vessels

- FNP-O-GMP-10.0, Revision 3, General Piping System Inspection

The inspector noted that procedure FNP-O-MP-12.3 for PM of the Air Start System was written as if the entire system (both "A" and "B" compressors) would be taken out of service and put back in service as a system rather than one train at a time. In actual practice, Train "A" was taken out and put back in service before the Train "B" was taken out of service. This sequence was covered in the Work Authorization and was sequenced in the clearance and tag-out process. However, the procedure did not detail this sequence and therefore did not provide signoffs compatible with this sequence. There was nothing wrong with what was actually done, but the procedure needed to be revised to provide for proper signoffs. Maintenance supervision initiated a procedure change after the job was completed.

b. WA 448937; Charging Pump 2B 4KV Disconnect Switch PM; and WA 448916; Charging Pump 2B Motor PM

These WAs covered PM of the 2B Charging/HHSI Pump Motor and 4KV Disconnect Switch as part of the 6 month pump PM and Surveillance. The inspector observed PM of the "A" train switch and megger testing of the 2B Motor. For these activities, the inspector verified compliance with TS, FSAR, clearance and tag order requirements, and procedural requirements of FNP-O-2-EMP-1102.01, Revision 0, 4KV Disconnect Switch Maintenance and Space Heater Operability Check, and FNP-O-EMP-1701.01, Revision 3, Electrical Equipment Condition Testing.

c. WA 448477; 2C Diesel Generator Fuel Oil Storage Tank Level Transmitter Calibration

This WA covered the 6 month calibration of the 2C DG Fuel Oil Storage Tank Level Transmitter. The inspector observed this activity and verified compliance with licensee procedure FNP-O-IMP-226.10, Revision 2, Diesel Fuel Oil Storage Tank 2C Level Loop Calibration NSY52LT0508.

d. WA 447937; 2D Service Water Pump Motor Preventive Maintenance

This WA covered cleaning, inspection, and testing of the 2D SWS pump motor as part of the annual pump PM and surveillance. The inspector observed megger testing of the motor. For this activity, the inspector verified compliance with TS, FSAR, clearance and tagorder requirements, and procedural requirements of FNP-0-EMP-1530.01, Revision 7, General Motor Maintenance, and FNP-0-EMP-1701.01, Revision 3, Electrical Equipment Condition Testing.

e. WO 448794 and 96000939; Five Year Discharge Test of #2 Service Water Battery

This test was satisfactorily performed IAW the above WOs and procedure 0-STP-906.1, Service Water Building Battery Performance Test. The test was performed on the "as found" number 2 battery with some existing corrosion on several cells' electrical connections (cell 2, 13, 16, and 19 - "as found" conditions appropriately not cleaned up for the test). All test equipment was properly used and calibrated. The ampere meter was not able to be null balanced (zero-ed) and was replaced. The removed meter was appropriately documented and returned to the calibration lab. The inspector was present for a portion of the test especially initiation of the discharge. The inspector discussed the details of the test with EM crew and their foreman. The discharged battery met the acceptance criteria of the procedure. The personnel performing the test were capable and knowledgeable about the test.

Due to a rapid temperature change and heavy rains, the interior of the SWIS was moist. Normal ventilation had drawn in the moisture laden atmosphere. The battery room exhaust fans concentrated moisture in the room. The areas around the batteries were in this moist environment. The electricians had to take extra precautions for electrical equipment protection and for their physical safety. The floor of the SWIS was scummy with water as were the tops of the battery cells. The inspector pointed out this condition to plant management and operations personnel.

As the test progressed, the inspector toured the SWIS and observed that the small molded case breakers controlling the internal heaters for the 4160 Volt breaker cubicles were in the "off" position. Researching this condition, it was determined that for SBO EDG initial (LOSP) electrical loading considerations, the breakers were administrative placed in off. The inspector discussed the situation with the Electrical Maintenance staff and the operations manager. In the "on" position, the breakers would reduce the possibility of breaker failure due to moisture intrusion. As of this writing, the EM staff had generated a Plant Modification Idea Submittal Form (dated March 8, 1996) that would be reviewed by the plant's Configuration Control Board. The submittal would have the heater breakers remain "on" during normal operation but should a LOSP or SI occur, the heater breakers would trip and not be automatically reloaded on to its voltage source.

f. WO 96000599; Unit 2 Turbine-driven Auxiliary Feedwater Speed Control Work

The above WO replaced and tested speed control components (EGM and the RGSC, DR 535175 related) in the circuitry controlling the Unit 2 TDAFW pump. The inspector observed the satisfactory functional testing of the pump and fine tuning adjustments made by operations and the I&C technicians. Additionally, the inspector observed the satisfactory surveillance test of the unit after it had been properly released by maintenance. Subsequent to its return to service, the licensee had performed three weeks of twice a week pump surveillance to conservatively re-enforce that the fix was satisfactory. The inspector observed three of these tests (2-STP-22.19, one each week) and the speed control system attained the acceptance criteria for speed whose value did not vary by more than a few r.p.m. (4071 to 4061).

g. WO 535177; Unit 2 Urgent Rod Failure Alarm

On February 4, the MCB annunciator for Rod Control Urgent Failure came into alarm on Unit 2. The resident inspectors were notified and responded to the site. After a preliminary inspection, a DR was written to initiate troubleshooting and repair of the 2AC Rod Control Power cabinet by I&C.

The inspectors monitored this critical work activity. Initial preparations by the licensee included discussions with the vendor in order to develop appropriate WO instructions, and to make ready the DC Hold Cabinet which is infrequently used. A careful and thoughtful approach to this problem allowed the licensee to discover that power supply fuses to the DC Hold Cabinet were partially blown (2 of 3 phases) before attempting to transfer control power. Coordination between I&C, EM, and Operations personnel was commendable. A delay was experienced when the replacement fuse type could not be located in the licensee's fuse manual. After reviewing the technical manual and additional discussions between EM supervision, corporate engineering and the vendor, the proper fuses were identified. The fuse manual was subsequently updated. An inspector observed the successful replacement of fuses and transfer of control power for Shutdown Bank A (Group 2) from its normal 2AC Rod Control Power to DC Hold power.

The failure detection circuit card for power cabinet 2AC indicated that one of the Group C regulation circuit cards had failed. Pursuant to the detailed work instructions of WO 535177, an inspector observed I&C technicians systematically replace circuit cards in power cabinet 2AC. All I&C work was controlled by the I&C foreman who was in constant communication with the MCR, and under direct oversight by the I&C group supervisor. The failure indication alarm cleared when the "phase control" printed circuit card in position H1 was replaced. Whereupon, control power for Shutdown Bank A was transferred back to the 2AC cabinet. The entire evolution was conducted in a deliberate and methodical manner consistent with the critical nature of this work and susceptability for dropping a control rod. I&C, EM, and Operations performed well.

3.2 Maintenance Program Implementation (62700)

During the weeks of February 26 and March 4, three region based inspectors were on site to inspect maintenance program implementation, with a special focus on BOP systems. The SALP for the period September 26, 1993 through March 25, 1995, indicated that BOP equipment performance had adversely impacted plant operation with an increasing trend noted in the final six months of the assessment period. To evaluate the area of BOP maintenance program implementation, the inspectors reviewed procedures, interviewed licensee personnel, observed work activities in progress, and examined selected records as indicated below.

Procedure Review

The inspectors reviewed the below listed maintenance procedures to confirm that the procedures were prepared to adequately control maintenance of plant equipment within regulatory requirements. Observations were made in the areas of technical content and human factors. Observations were compared with the FSAR, Technical Specifications, vendor technical manuals, and other licensee documents.

Procedures Reviewed

Identification	Rev	Title/Subject
FNP-0-ACP-52.1 6/15/95	0	Guidelines for Scheduling of On-Line Maintenance
FNP-0-ACP-52.2 6/15/95	0	Work Order Development and Approval
FNP-0-GMP-0.2 9/8/93	6	Repair and Replacement Instructions for ASME Class 1, 2, and 3 Components
FNP-0-GMP-1 1/16/94	16	Preventive Maintenance Procedure
FNP-0-MP-99.0 2/2/96	2	Mechanical Maintenance Procedure
FNP-0-GMP-27.2 4/22/92	3	Disassembly, Inspection, Repair and Reassembly of Safety related Check Valve

Procedures Reviewed

Identification	Rev	Title/Subject
FNP-0-MP-72.0 10/10/95	9	Establishing Freeze Seals on Safety Related Piping System
FNP-1-IMP-215.4 10/7/92	8	Feedwater Pump Speed N1N21PT0508
FNP-1-STP-22.24 4/25/95	7	Aux Feedwater System Check Valve Reverse Flow Closure Operability Test
FNP-2-IMP-0.12 3/6/95	1	Turbine Building Instrument Air Line and Pressure Regulator Preventive Maintenance Procedure

Relative to procedure FNP-0-MP-72.0, the inspectors noted the following:

- The procedure did not specify where on the pipe circumference, to place the thermocouples.
- The licensee did not have a documented standing contingency plan for freeze seal failure.
- The procedure did not make any provisions for evaluation by a qualified engineer of any potential structural damage.

Except as noted above, the maintenance procedures were appropriate for their intended application. The licensee stated that they would evaluate the inspectors comments and make changes to FNP-0-MP-72.0 as appropriate.

The combination of work orders, technical manuals and procedures provided an acceptable level of direction for the accomplishment of BOP work.

Observation of Maintenance Work Activities

The inspectors accompanied maintenance personnel performing repair activities in the field to determine whether the work activities were consistent with applicable requirements. The work covered included both safety-related and non-safety-related work activities. Observations included evaluations to determine whether non-safety related systems were being controlled in a manner similar to safety-related systems. The inspectors reviewed the procedures referenced in the applicable work orders prior to the commencement of work. Other activities evaluated included, but were not limited to the following: pre-job planning; qualification of craft personnel; craft personnel's understanding of the scope of the task; adequacy of supervisory oversight; the apparent cause of a failure appeared to be addressed by appropriate corrective actions; procedures were available and followed; a lubrication control system was in effect for mechanical systems; work instructions were sufficiently detailed for the performance of the assigned task; approved drawings and/or vendor manuals were accessible; tagging of nonconforming materials was accomplished; cleanliness controls were maintained; and documents certifying the completion of work steps were completed as the work progressed. The following work activities were witnessed by the inspectors.

a. WO 533825; Unit 1 Reactor Makeup Water Pump 1A Overhaul

This item was safety-related and involved disassembly of the pump, removal of the shaft, seals and bearings and replacement with new components. During re-assembly, the craftsmen made an error when pressing on the new bearing causing the new shaft to be destroyed due to scoring and upsetting of threads. A second new shaft was procured and a new bearing was successfully pressed on the new shaft. The inspector attributed the failure to properly press the bearing onto the new shaft as lack of attention to detail in that the craftsman selected an improper sized tool (sleeve) when pressing the bearing onto the shaft. The problem was readily apparent and was corrected by the craftsmen before proceeding any further with the overhaul. The inspector noted the pump assembly was controlled in compliance with all applicable procedure requirements.

Work instructions were clear except procedure FNP-0-MP-99.0, Revision 2, which included a step to drain the oil from the pump casing, but the inspector noted the procedure failed to include a step to refill the casing with oil after assembly was complete. The inspector noted the craft, in fact, filled the pump casing with the proper oil prior to running the pump. Also, a step was provided in the work order, Step 5, to refill with Regal R&O type 68 oil. To assure continuity in implementing the work activity for future work accomplished using this procedure, a step should be included in the procedure. The licensee was considering this change.

After the licensee had completed the work on the above pump, the inspector performed a record review to determine the prior history of bearing failures. The inspector noted that since 11/16/93, the pump had been rebuilt 5 times with new bearings due to bearing problems. At least two root cause analysis actions had been performed and the most likely cause of the bearing problems was attributed to inadequate pump to motor alignment. To assure the craft were properly aligning the pump to the motor a training program for all mechanical maintenance craft was being conducted in early 1996.

The inspector review of the pump manual noted a requirement to perform two alignments. One was considered an initial alignment and was included in the licensee's procedure for alignment of pumps to motors. The second alignment was to be performed after the pump had been operated long enough for the components to reach an equilibrium consistent with the liquid. The vendor manual required the pump to be shut down after reaching this temperature and a re-alignment check be done immediately. The inspector noted the licensee had not been performing this final alignment. The licensee contacted the pump vendor and received directions that this final alignment was required if the liquid being pumped exceeded 50°F above ambient. In this instance, the water temperature was approximately 100°F. and within the 50°F span. Therefore, the licensee elected not to do the final alignment. The licensee also advised that, for this pump manufacturer, no other pumps on site exceeded the 50 degrees span.

b. WO 506970; Number 5 River Water Pump Packing Installation

This item was non-safety related and involved a relative minor task of replacing a leaking gasket on the pump. The inspector noted that written instructions (work order M 00506970) were provided to the craftsmen. Although the component was non-safety related, the work order listed the work as safety-related and the documentation and sign-offs were controlled in the same manner as a safety related component.

c. FIN Team - 1A 1st Stage Drain Tank High Level Controller Air Signal Tubing Connector Repair

This item was non-safety related and involved the FIN (fix it now) team reconnecting the air instrument line. The inspector observed this maintenance activity after the repairs were completed to determine if the replaced connection was experiencing excessive vibration. The inspector' observation of the repair noted minimal amount of vibration on the instrument air line in the area where the lines had previously broken. The inspector noted that the mechanic failed to replace the cover on the 1A 1st stage drain tank high level controller. The above oversight is an example of lack of attention to detail.

d. WO 507326; Chemical Injection Pump Repair

This item is non-safety related and involved the replacement of the failed diaphragm tube. The inspector reviewed the work package and technical manual, and observed repair activities in the auxiliary building and the maintenance shop.

The work order directed the craft technicians to inspect and repair the pump using the vendor manual for guidance. The inspector noted that the technicians had difficulty removing the diaphragm from the pump cylinder. The vendor manual recommended that the diaphragm be removed while the cylinder of the pump is secured in a vise. Attempts were made at the pump location and in the maintenance shop. After a number of attempts were made, the technicians put the cylinder in a vise and removed the diaphragm by pushing with a blunt ended rod as described in the vendor manual. The inspector consider this another example of lack of attention to detail.

Also the inspector questioned why the O-rings were not replaced with the diaphragm, the technicians indicated that they were not damaged and did not need replacement. This is not consistent with the pump technical manual Ref. 1700.44-3, which states "Replace the diaphragm and O-ring check valve seals annually unless experience indicated more frequent need. ... replace O-rings at the same time that diaphragm is replaced".

A review of the plant PM procedure index revealed only lubrication PMs for the Chemical Injection Pumps. The licensee indicated that they did not have a PM to annually, or at any periodicity, replace the diaphragms and O-ring seals, or an evaluation to support other preventive maintenance in place of the maintenance recommended by the pump manufacturer.

It appears that guidance gleaned from the technical manual was not adequately considered. The licensee's failure to replace the O-rings as recommended by the technical manual is considered a weakness.

With the exception of the multiple unsuccessful attempts to remove the leaking diaphragm, the work was accomplished in an adequate manner. The inspector verified that proper parts and consumables were used. Coordination with operations was good. The technicians were knowledgeable and properly qualified.

WO 538716; 1B SGFP Speed Controller Card Repair

The plant determined that SGFP controller SC-509C C8-232 failed, which caused a "B" SGFP turbine runback. This item is non-safety related and involved the calibration and replacement of a circuit card. The inspector observed calibration and installation activities in the I&C maintenance shop and the control room back board area.

The WO specified calibration of the SGFP controller circuit card in accordance with FNP-1-IMP-215.4, Revision 8, step 7.11. The inspector noted after the technicians had performed the calibration sequence, that the calibration results were unacceptable. After some examination of the circuit controller card by the technicians, they removed three or four jumpers from the card and commenced to run the calibration scheme again. When questioned, the technicians indicated that the jumpers they removed were not appropriate for the specific application for this circuit card as indicated in Table 2 in Procedure FNP-1-IMP-215.4. After the removal of the inappropriate jumpers and a gain adjustment, the calibration was successfully completed.

FNP-1-IMP-215.4, Revision 8, step 7.11 had a note listed ahead of the work instructions that stated "<u>NOTE</u>: IF CARD IS TO BE REPLACED, REFER TO TABLE 2 FOR JUMPER LOCATION."

Clearly the technicians did not follow the directions of the note prior to starting the calibration sequence. However, the component was still under work order control and the problem was discovered prior to returning it to service. This is considered another example of lack of attention to detail.

The inspector noted a number of wheeled instrument carts, chairs with wheels and wheeled work platforms unsecured and unattended in the control room back board area. When asked, the licensee indicated that there are a number of panels in the back board area that are sensitive to shock and if jarred have the potential of tripping the plant. The inspector expressed concern that unsecured wheeled furniture, work platforms and instrument carts could be seismically shaken into or inadvertently bumped into a sensitive panel, resulting in a potential plant trip. Licensee management directed appropriate plant supervisors to develop controls for wheeled equipment in the back board area.

The inspector considered this a weakness in that wheeled equipment was not controlled in the control room back board area.

f. WO 538403; River Water Duct Sump Duct Pump B ran continuously but did not pump.

This item is non-safety related and involved trouble shooting activities, replacement of wiring and the sump pump alternator. The inspector reviewed the work package and observed repair activities in the river water building and the duct sump.

The inspector noted the following material condition deficiencies:

- The floor of the B train bay in the river water building was flooded. The licensee informed the inspector that the condition had been identified and design change requests initiated to correct the condition.
- Two electrical panels in the duct sump were missing fasteners, one of ten on one panel and five of ten on the other. This was indicative of lack of attention to detail on the part of the last mechanics who worked on those panels. The fasteners were replaced with WO M 00538404.
- The vertical pipe support intended to support the sump pump discharge piping was loose and provided no support to the piping.

The electricians were knowledgeable and properly qualified. The work was accomplished in an adequate manner. The inspector verified that proper parts and consumables were used. Coordination with operations was good.

g. WO 538720; Check valve failed to pass reverse flow closure operability test, investigate and repair

This item is safety related and involved disassembly, inspection, repair, reassembly, and retest of the 1B Motor Driven Auxiliary Feedwater Pump discharge check valve (Q1N23V 0002B) due to unacceptable back flow leakage.

The inspector observed the pre-job briefing and the pre-job review of the WO, General Maintenance Procedure (FNP-0-GMP-27.2) for safety related check valves, and the technical manual in the maintenance shop. Subsequently, the inspector witnessed disassembly, inspection, cleaning, reassembly, and retesting of the valve in the field.

From observations of the work and discussions with the maintenance craft personnel the inspector determined that the craft were knowledgeable of the disassembly/assembly process, used appropriate and calibrated tools, and followed instructions in the vendor technical manual. Coordination between Operations and Maintenance was excellent. The job flowed smoothly and without unwarranted delays from the valve repair to retest and return of the valve to service.

The inspector concluded that the maintenance was performed in a well coordinated manner.

h. WO 74572; Rebuild Heater Drain Tank Pump

This item is non-safety related and involved the disassembly, refurbishment and reassembly of a spare heater drain tank pump to be put in stock after being rebuilt. The inspector witnessed portions of the reassembly of the pump in a warehouse area. From the observations and discussions with the maintenance craft personnel the inspector determined that the craft were knowledgeable of the assembly process, used appropriate and calibrated tools, and followed instructions in the vendor technical manual.

The inspector concluded that the maintenance was accomplished in an adequate manner.

i. WO 503088; Valve Controller Blowing Excessive Amount Of Air

This item is non-safety related and involved trouble shooting and repair of the positioner air leak for the Gland Seal Steam Condenser bypass valve N2N21V 0902 by work order WO M00503088. Also, the WO indicated that a preplanning walkdown showed that the Positioner/Valve setup (calibration) needed to be performed. The licensee issued WA 453297 to perform the instrument air line and pressure regulator PM for controller F0902 and WA 453295 to calibrate the Positioner/Valve setup.

The inspector observed the trouble shooting and the instrument air line and pressure regulator PM. The craft located the source of air leakage as a relay on top of the 3570 positioner. The job was delayed when the technical manual could not be located to identify the part number. A search of the stock room located similar relays but these did not appear to be exact duplicates of the defective relay. I&C referred this problem to QC who contacted the vendor and obtained the part number. The part number matched some relays in stock and one was subsequently installed to correct the air leak.

The instrument air line and pressure regulator PM was controlled by procedure FNP-2-IMP-0.12. Step 7.1.4 required that the regulator as found outlet pressure be measured and recorded and then the air line blown down until no moisture or debris could be detected. Step 7.1.10.2 of the procedure required that the regulator outlet pressure be measured again and adjusted to the as found pressure recorded in step 7.1.4. The inspector noted that the as found pressure of 21.5 psi could not be achieved. The as left pressure was 20.1 psi.

Additionally, step 7.1.10.2 required that the regulator outlet pressure be set at the value specified in Table 1 of the procedure if higher than the as found pressure. However, valve N2N21V 0902 was not included in Table 1.

Failure to implement the procedure requirement in step 7.1.10.2, the absence of valve N2N21V 0902 in Table 1 of the procedure, and the unavailability of the technical manual were discussed with plant management and identified as further examples of lack of attention to details. Management stated that strict adherence to procedures will be reemphasized to plant personnel and I&C is reviewing the acceptability of the as left pressure and the PM to determine if procedure revision is warranted.

With exception of the above items the inspector concluded from observations of the work performance and discussions with the I&C personnel that the craft was knowledgeable of the task and performed the task in a skillful manner.

The administrative controls and work practices noted by the inspector on the BOP were being controlled in an acceptable manner. The inspector noted a number of examples of lack of attention to detail which were considered a weakness. However, work activities were conducted by properly qualified personnel using appropriately calibrated tools in accordance with appropriate work instructions. The level of supervisory oversight of work activities was appropriate.

BOP Plant Equipment Deficiencies Resulting in Plant Challenges

From December 1994 through February 1996 there were approximately 32 occasions where BOP deficiencies resulted in plant trips, power reductions or other challenges to plant safety systems as indicated below. The inspector interviewed licensee personnel and reviewed the incident reports and selected records associated with the below listed plant challenges to evaluate: the cause; the licensees evaluation and corrective actions; the licensee's determination of the problem extent; and actions to prevent recurrence.

DATE	UNIT	SR/BOP	DESCRIPTION	Incident Report
2/29/96	1	BOP	1B SGFP experienced a sudden, unexpected run back when a speed control circuit card failed. Prompt operator response minimized impact on plant operation.	1-96-065
2/10/96	1	BOP	A scheduled weekend ramp down from 100% to 15% power to conduct post-outage chemistry flushes of the SG's.	None
1/30/96	2	BOP	A scheduled weekend ramp down from 100% to 15% power to conduct a three day secondary side outage - (a) Flush SG's to reduce sodium, (b) Locate and repair minor condenser tube leak (about 1GPM), and (c) Replace SGFP and MTG Moog valves.	None
1/23/96	2	BOP	#1 governor valve for the main turbine would not properly position itself per demand from the DEHC system. Unit 2 ramped down to 95%, #1 GV Moog valve replaced.	2-96-027
1/22/96	2	BOP	2B SGFP governor valve control card (NCD 7300 series) failed. Unit 2 ramped down to 65% to take SGFP off line and replace card.	2-96-023
11/28/95	2	BOP	Turbine/reactor trip from 100% power due to loss of DEHC OPC while a Drop 2 circuit board was being changed out on line.	2-95-334
11/14/95	2	BOP	Unit ramped down from 100% to 79% power to repair leak on 2B circulating water pump RTD connection.	2-95-324
11/12/95	1	BOP	1A circulating water pump secured due to oil leak from a cracked thrust bearing RTD fitting, loss of oil wiped the upper sleeve guide bearing. Escalation to full power was slowed while pump motor was replaced.	1-95-317

DATE	UNIT	SR/BOP	DESCRIPTION	Incident Report
11/10/95	1	BOP	Unit taken off line for forced outage to repair hard ground discovered on MTG #9 bearing due to crimped RTD.	1-95-315
11/5/95	1	BOP	1B SGFP tripped on low lube oil pressure while operators were realigning lube oil pumps, MTG was promptly tripped and reactor power reduced from 27% to Mode 2.	1-95-306 1-95-312
11/4/95	1	BOP	1A MFW regulating valve suddenly failed full open initiating an overfill transient, operators promptly took manual control of regulating valve and restored 1A SG water level.	1-95-310
8/11/95	2	BOP	Power reduced to 15% power over the weekend to cleanup SG's (blowdown excess sodium) and perform boron saturation.	None
6/29/95	2	BOP	Operators manually tripped the main turbine (reactor power about 15%) due to high condenser back pressure caused by inadequate steam pressure to SJAEs.	2-95-163
6/25/95	2	BOP	Reactor tripped due to 2B main feed pump speed control failure and HP governor valve failed to open	2-95-157
6/21/95	2	BOP	Rapid power reduction to 60% power due to erratic LP governor valve and unexpected closing of HP governor valve on 2B main feed pump	2-95-160
6/11/95	1	SR	Reactor tripped when MSIV 3370C went closed, caused by short circuit of protection relay due to water dripping from leaking room cooler	1-95-147
6/11/95	2	BOP	Rapid power reduction from 15% to 2% power due to loss of main feedwater when 2B main feed pump HP governor valve went shut	2-95-148
6/10/95	2	BOP	Reduced reactor power from 64% to 15% to cleanup elevated SG sodium levels	None

DATE	UNIT	SR/BOP	DESCRIPTION	Incident Report
6/5/95	2	BOP	Reduced power from 17% to 2%, again, to repair main turbine EHC fluid leaks	2-95-140
6/4/95	2	BOP	Reduced power from 16% to 2% to repair main turbine EHC fluid leaks	None
6/3/95	2	BOP	Reactor manually tripped from 32% power due to EHC line break on 2A main feed pump	2-95-141
6/1/95	2	BOP	Reactor manually tripped from 32% power due to EHC line break on 2A main feed pump	2-95-137
5/15/95	2	BOP	Shutdown for two weeks due to sodium contamination on secondary side	None
5/10/95	2	BOP	Reduced power from 40% to 15% due to high sodium in the secondary	None
5/7/95	2	BOP	Reduced power from 95% to 15% due to high sodium in the secondary	None
5/4/95	2	BOP	Reduced power from 48% to 15% due to high sodium in the secondary	None
5/2/95	2	BOP	Reduced power from 75% to 15% due to high sodium in the secondary	None
2/16/95	1	BOP	Rapid power reduction to 49% due to loss of Phase 3 main transformer cooling	1-95-048
1/27/95	2	BOP	Shutdown for four days to modify DEHC system similar to Unit 1	Perform 1-95-015 on U2
1/13/95	1	BOP	Reactor tripped due to internal DEHC system failures	1-95-015
12/25/94	2	BOP	Reactor tripped due to internal DEHC system failures	2-94-296
12/18/94	2	BOP	Reactor tripped due to spurious DEHC actuation of auto-stop latch circuitry	2-94-290

Some repetitive type problems were noted in the review of the above listed Incident Reports, such as steam generator feed pump problems, Moog valve failures due to clogged filters, valve wear and corrosion, water and oil leaks that caused problems with other components, high sodium in the secondary, and PC controller card failures. Based on the sample review of maintenance activities, the inspectors concluded that work activities being conducted by the maintenance group did not contribute to equipment failures due to improper work practices. The inspectors did not note any common cause associated with the problems. The inspectors noted that once a problem was identified and determined not to be an isolated event, aggressive actions were taken or planned to overcome the problems described in the incident reports. This indicated the licensee is pursuing permanent resolution of these problems. The inspectors considered that normal plant aging may be a contributor to the recent increase in the equipment problems that potentially affect or challenge the safety related systems.

In order for the licensee to become more proactive in detecting potential problems before they challenge or trip the plant, several initiatives have been started by the licensee. The inspectors noted the licensee had established a task team, composed of various organizations. As an example, one team included Westinghouse to evaluate and implement corrective actions, where appropriate, on the turbine, steam generator feed pumps, servo or Moog valve problems and DEHC systems. Additionally, during the inspection, the inspectors noted the licensee was performing an extensive review, titled Single Point Failure Vulnerability, of those BOP components which could cause a "single point event". The inspectors considered these initiatives a strength and should provide valuable data to prevent or correct potential deficiencies which should reduce challenges to safety systems.

Maintenance Training

The inspectors reviewed craft training requirements and documented records for training completion of various craft personnel that had performed maintenance work in I&C, electrical, and mechanical areas. The review was evaluated against the criteria specified in FSAR, Section 13.2.2. The craft records selected were based on the inspectors field observations of maintenance activities performed during this inspection.

FSAR Section 13.2.2.3, Instrumentation and Control Training Program, specifies a course of formal training of approximately 33 weeks in duration and covering basic electricity and electronics; fundamentals of pressure; temperature; level and flow measurements and control, NSSS instrumentation such as 7300, SSPS, DRPI, rod control, incore and excore; primary and secondary plant systems; and on-the-job training. The inspectors selected one craft person involved in the evaluation and rework activities discussed above in FNPIR 1-96-065, work order # M00538716 and verified he had completed the minimum FSAR training requirements. The inspectors noted the craft person had also received numerous additional training classes above the training requirements specified in the FSAR. No deficiencies were noted.

FSAR Section 13.2.2.4, Mechanical Maintenance Training Program, specifies a course of formal training of approximately 21 weeks in duration and covering piping systems, diesel generators, rotating machinery, lubrication, machinery balancing, vibration and alignment, principles of rigging, hydraulics, primary and secondary plant systems, and on-the-job training. The inspectors selected two craft persons involved in the rework activities discussed above in work orders # 00533825, repair of Unit 1 reactor makeup water 1A pump, and #00538720, Unit 1 motor driven auxiliary feedwater B pump discharge check valve, and verified one craft person on each work order had completed the minimum FSAR training requirements, except machinery balancing. For machinery balancing, the licensee's stated that craft personnel do not perform machinery balancing but other organizations, such as Westinghouse would perform machinery balancing, if required. However, craft personnel do perform vibration and alignment on machinery. The inspectors verified one craft person was trained in vibration checks and alignment techniques. The inspectors noted both craft persons had received numerous additional training classes above the training requirements specified in the FSAR. The inspectors also reviewed the completed and graded tests for one craft for pumps and couplings. The individual selected had successfully passed both tests. No deficiencies were noted.

FSAR Section 13.2.2.5, Electrical Maintenance Training Program, specifies a course of formal training of approximately 27 weeks in duration and covering basic electricity fundamentals, single and three-phase motors, dc motors, ac and dc circuits, batteries, switchgear and protective devices, primary and secondary plant systems, and on-the-job training. The inspectors selected one craft person involved in the evaluation and rework activities discussed above in WO M 00538403 and verified completion of the FSAR minimum training requirements. The inspectors noted the craft person had received numerous additional training classes above the training requirements specified in the FSAR. No deficiencies were noted.

Overall Conclusions

A weakness was noted relating to some lack of attention to detail. A weakness was also noted relating to the licensee's failure to incorporate vendor recommendations into the maintenance program, without evaluation. Generally the maintenance procedures were appropriate for their intended application. Notwithstanding, work activities were conducted by properly qualified personnel using appropriately calibrated tools in accordance with appropriate work instructions. The level of supervisory oversight of work activities was appropriate. The combination of work orders, technical manuals and procedures provided an acceptable level of direction for the accomplishment of BOP work. The incident reports reviewed were generally comprehensive, with adequate corrective actions and root cause evaluations performed where appropriate. The inspectors concluded that work activities were being conducted in an acceptable manner, with some inattention to detail noted by the inspectors. Maintenance work practices were not noted to contribute to equipment failures. The inspectors did not note any common cause associated with the problems. The inspectors noted that once a problem was identified and determined not to be an isolated event, aggressive actions were taken or planned to overcome the problems described in the incident reports. This indicates the licensee is pursuing permanent resolution of these problems. The inspectors considered that normal plant aging may be a contributor to the recent increase in the equipment problems that potentially affect or challenge the safety related systems.

3.3 Surveillance (61726)

The inspectors observed/reviewed portions of selected surveillance activities as detailed below to determine if these activities were conducted in accordance with TS, approved procedures, and appropriate industry codes and standards. In addition to verification that procedures were followed and TS requirements were met, the inspectors verified that personnel were knowledgeable and qualified, that required clearance and tagging requirements were met, and that calibrated measuring and testing equipment was used.

a. WA W00448100; #1 Diesel-Driven Fire Pump Engine Surveillance

This WA covered the 18 month surveillance/PM of the #1 DDFP engine to meet paragraphs 9B.C.2.2.B.3 and 9B.C.9.2.B.3 of the FSAR. The surveillance/PM included the Fuel Oil System, Lubrication System, Air System, Coolant System, and miscellaneous checks and adjustments. The inspector observed portions of these activities and verified compliance with the FSAR and licensee procedure FNP-O-FSP-400, Revision 2, Diesel-Driven Fire Pump Inspection (N1P43M001, N1P43M002). The inspector observed certain weaknesses during the performance of this activity.

Pre-job planning for this surveillance/PM was poor. A number of parts and supplies required for the job, including oil and cleaning solvent, were not pre-staged prior to taking the pump out of service. A significant amount of time was required to determine and obtain the correct parts and supplies, resulting in the pump being out of service significantly longer than should have been required.

FNP-O-FSP-400 was not followed exactly as written in two cases - (1) the method used for measurement of the turbocharger bearing end play and (2) the sequence for adjusting valve clearances. Relative to the bearing end play measurement, the procedure specified a specific technique using a dial indicator attached to a bolt. In actual practice, the dial indicator was attached to a magnetic base. For the valve adjustment, the procedure specified adjusting the crosshead adjusting screws. This step in the adjustment process was not needed unless the crossheads were worn. Since the crossheads were not warn, this step was not performed. In both cases, there was nothing wrong with what was done, but the words in the procedure needed changing to agree with the actual practice. As part of the post-job process, procedures are marked-up for changes and improvements. The need for the procedure change relative to the valve adjustment sequence, was identified for a procedure improvement by the craft during the post-job mark-up. After questioning by the inspector, the licensee also agreed that the words relative to measurement of the bearing end play needed clarifying.

The inspector also reviewed in-process evidence, i.e., recent marked-up procedures and revisions, that demonstrated the craftsmen were providing post job marked-up procedures for future revisions.

b. WA's W00448548 and W00452515; Fire Pump Diesel Start Battery Banks A,B,C, and D Surveillance

These WAs covered the weekly and 18 month surveillance/inspection of the Fire Pump Diesel Start Batteries to meet paragraphs 9B.C.2.2.C.1A and B, 9B.C.9.2.C.1A and B, 9B.C.2.2.C.3A and B, and 9B.C.9.2.3A and B of the FSAR. The inspector observed portions of these activities and verified compliance with the FSAR and licensee procedures FNP-0-FSP-300, Revision 2, Fire Pump Diesel Starting Battery Weekly Inspection, and FNP-0-FSP-302, Revision 0, Fire Pump Diesel Starting Battery Inspection.

c. FNP-1-STP-73.1; Hot Shutdown Panel Operability Verification

In response to problems at the Hatch Nuclear Plant, SNC executive management committed to functionally test the HSDP at FNP. Operations technical support staff developed a new Unit 1 procedure FNP-1-STP-73.1, Hot Shutdown Panel Operability Verification, to verify operability of those HSDP components that could be safely tested at power. Like Hatch, the HSDP at FNP has rarely been used and most components have not been controlled from the HSDP since initial startup testing. Considering the importance of this system and the possibility of discovering significant problems, the inspectors observed almost all of the HSDP tests conducted on Unit 1.

Pre-test evolution briefings were conducted by the test director for each HSDP component that was tested IAW its own specific Appendix to STP-73.1. Exceptional care and caution was taken during the execution of these tests to minimize any adverse impact on unit operation. In general, STP-73.1 was well written and only required a few minor changes during the course of testing. At which time, test activities were secured and TCNs issued as necessary. The test director and assigned operators did an excellent job in controlling and conducting this test evolution. For Unit 1, all HSDP controlled components tested by STP-73.1 performed per design except the RCP seal injection flow control valve (HCV-186). When the HSDP-A transfer switch for HCV-186 was selected to the LOCAL position IAW Appendix I, it immediately failed full open and could not be throttled. FNPIR 1-96-77 was initiated and a root cause team was assembled. Initial troubleshooting discovered HCV-186 was miswired and a controller circuit card jumper was also improperly installed.

HCV-186 was subsequently repaired, recalibrated, and successfully retested.

Incorporating lessons learned from the Unit 1 experience, Operations technical support was revising STP-73.1 for Unit 2 and planned to conduct HSDP testing of that unit during the next inspection report period. The inspectors will also monitor those activities as part of the routine core inspection program. Furthermore, resolution of HCV-186 and any additional Unit 2 failures will be examined in further detail and tracked as IFI 50-348, 364/96-02-02, HSDP Test Failures.

d. FNP-2-FSP-405, Preaction Sprinkler Test (18 month PM and test per old TS)

An inspector observed the 18 month routine surveillance test and PM of pre-action sprinkler 2A-59. Plant performance team personnel conducted the test IAW FSP-405 as authorized by WA 448063. During the course of the surveillance test, the clapper for 2A-59 failed to automatically open when an associated smoke detector was actuated by a small, hand held smoke canister. The clapper also failed to open when team personnel attempted to trip it manually using the emergency switch. Subsequent troubleshooting determined that the automatic solenoid valve and the internal diaphragm of the multi-matic valve were not working properly to relieve the pressure holding down the clapper latch. Further review of FSP-405, Data sheet 3, indicated that five of 11 Unit 2 preaction sprinkler systems had experienced recent similar failures.

The inspector questioned Operations management and the performance team leader regarding the high failure rate. Although Operations had already instituted additional one hour fire watches, the inspector was concerned that this may not be adequate for critical fire areas that would require continuous fire watches if their sprinklers were inoperable. In response to the inspector's concern, the licensee attempted to trip all remaining Unit 1 and 2 pre-action sprinklers to verify their operability. Several other failed sprinklers were discovered and appropriate fire watches were established. Nine failures were identified out of 28 pre-action sprinkler systems for both units. FNPIRs 1-96-71 and 2-96-78 were initiated and a root cause team was assembled to address the problem. The inspectors will continue to follow licensee efforts to discern the root cause and resolve this issue. This is identified as IFI 50-348, 364/96-02-03, Pre-action Sprinkler System Failures.

3.4 Followup Maintenance/Surveillance

a. (Closed) LER 364/94-02, Service Water Pumps' Lube and Cooling Valves Surveillance Not Performed

On December 14, 1994, it was determined that the required surveillance for Service Water Pumps' lube and cooling valves had not been performed and had exceeded the allowable grace period. The event was attributed to personnel error.

The inspector reviewed the following documentation to verify that appropriate corrective actions had been identified and performed:

- Root Cause Summary documenting cause and corrective actions
- Completed Surveillance Procedure FNP-L-STP-24.11 documenting acceptable completion of the missed surveillance
- Newly issued Desk Guide FNP-O-M-091, Outage Planning Surveillance Scheduling Desk Guide
- Documentation of completed review of all surveillance schedules to ensure correct schedules were in place

Based on review of corrective actions, this LER is closed.

b. (Closed) LER 348/95-03, Potential For Loss of Automatic Engineered Safety Features Actuation

On February 6, 1995, Train "A" of the Solid State Protection System (SSPS) for both Units 1 and 2 was determined to be potentially susceptible to a postulated high energy steamline break inside the respective unit high pressure turbine enclosure. Subsequently, Train "B" for both Units was determined to be potentially susceptible to a separate postulated high energy steam line break in the Turbine Building. For each postulated event, a single train of Automatic ESFAS logic could be rendered inoperable on the respective Unit. The root cause was attributed to the original SSPS design configuration.

The inspector reviewed the following documentation to verify that appropriate corrective actions had been identified and performed:

- Operations Night Order - including (1) compensatory measures to restrict maintenance and surveillance activities which could impact the reactor trip systems or ESFAS equipment until SSPS modifications were completed and (2) description of the condition and proper implementation of emergency procedures for responding to a main steam line break
- WOs 67156 (Unit 1 "A" Train), 67155 (Unit 1 "B" Train), 67158 (Unit 2 "A" Train) and 67157 (Unit 2 "B" Train), documenting prescription and completion of modifications to the SSPS systems to electrically isolate the power feeds for the SSPS field inputs from the logic cabinet power supplies in the event of a fault

Based on review of corrective actions, this LER is closed.

c. (Closed) LER 348/95-004, Actuation of Engineered Safety Feature Equipment Due to Inadvertent Contact While Installing a Test Lead

On April 26,1995, an inadvertent actuation of an Engineered Safety Feature (ESF) occurred. This occurred when a technician performing a surveillance test procedure allowed an energized test lead he was installing in the B1G sequencer cabinet to make inadvertent contact with a terminal inside a congested portion of the sequencer cabinet. The cause was attributed to personnel error.

The inspector verified that appropriate corrective actions had been identified and performed as follows:

- A signed statement by the person who performed inspection of the B1G Sequencer for evidence of arcing and other damage was reviewed.
- The technician involved in the incident was interviewed to verify that he had been coached on proper techniques for handling test leads in congested spaces.
- Documentation showing dissemination of information relative to the incident to personnel who utilize jumpers or test leads was reviewed.
- The Boldness Review of previous similar conditions was reviewed.

Based on review of corrective actions, this LER is closed.

d. (Closed) LER 364/95-004, Reactor Coolant Pump Bus Undervoltage Relays Dropout Setpoints Outside Operability Tolerance

On December 5, 1994, it was determined during surveillance testing that the Train "A" RCP Bus UV Relay dropout setpoint associated with the 2B RCP was outside the specified TS operability tolerances. Subsequently, it was determined that the Train "B" relay setpoint associated with the 2C RCP was also out of tolerances. The cause was attributed to relay setpoint repeatability, temperature sensitivity of the relays, and testing techniques.

The inspector reviewed the following documentation to verify that appropriate corrective actions had been identified and performed:

- History of surveillance testing of the setpoints showing that the frequency of testing has been increased from quarterly to monthly; and
- Revision 8 of FNP-2-STP-912.0, Reactor Coolant Pump Bus Reactor TRIP Undervoltage Relay Test, which changes test equipment and procedures to address the causes of the setpoint shift.

Based on review of corrective actions, this LER is closed.

4.0 ENGINEERING AND TECHNICAL SUPPORT (37551 AND 92903)

Inspectors periodically inspected onsite engineering/technical support activities (e.g., design control, configuration management, system performance monitoring, plant modification, etc.). Effectiveness of on-site engineering and technical group support of licensee efforts to identify, resolve and prevent incidents or problems were also inspected.

4.1 Computational Errors Affected Unit 2 Moisture Separator Reheator Drain Tank Manway Torques

On June 25, 1995, the manway gasket for the 2B MSR second stage drain tank blew out releasing a large amount of steam into the Turbine Building (see IR 50-364/95-13 and FNPIR 2-95-158). At that time it was determined that an inappropriate gasket material was used. By letter dated June 26, 1995, in response to REA 95-0893, SCS then recommended a suitable replacement gasket, with accompanying torque values, for all ten affected Unit 2 drain tanks (Unit 1 remained unaffected). However, due to computational errors by an SCS engineer and inadequate peer review the wrong torque values were provided contributing to the March 13, 1996, blow out of the 1A MSR second stage drain tank manway gasket. Although all torque values recommended by SCS in the June 26, 1995 letter were low, only the torque values for the MSR second stage drain tank manway bolts were significantly low. In this case the original recommendation was 950 ft. lbs., which after SCS recalculated was determined to be 1528 ft. lbs. A conference call was held on March 15, 1996, between a resident inspector and SNC/SCS personnel and management to discuss the cause(s) of the errors and any necessary corrective actions. By the end of the call, SNC management had promised to send the inspector applicable documentation, drawings, and calculations. The inspector will review this information to verify the licensee's conclusions, scope of investigation and adequacy of corrective actions. This is identified as IFI 50-364/96-02-04, Computational Errors Result In Inadequate MSR Drain Tank Manway Torque Values.

4.2 Engineering Projects Counsel Meeting

On February 7, a resident inspector attended most of a regular bimonthly EPC meeting in the PMD conference room. Some of the major engineering topics that the inspector heard discussed were: Switchyard automation; Reanalysis of room coolers as attendant equipment; Alternate SFP cooling system; On-line maintenance risk monitor; Security computer action plan; and Revised steam dump setpoint. The EPC was attended by responsible onsite and corporate engineering management and staff, and had good representation from other affected onsite organizations (e.g., Operations and Maintenance). The inspector concluded that the EPC continued to provide a positive service to the plant in coordinating the resolution of large and complex engineering projects that could involve considerable company resources.

4.3 Nuclear Operations Review Board Meeting

On February 21, a resident inspector attended an onsite meeting of the NORB chaired by the Vice President of the Farley Project. The frequency, composition, and review scope of NORB meetings are prescribed by TS 6.5.2. The NORB membership at this particular meeting was well represented with only one alternate present. A meeting agenda book is typically assembled by the Corporate SAER group and distributed to NORB members and interested parties sometime in advance of the meeting. In this case the meeting agenda book was dated February 7, 1996. The NORB Chairman led the meeting, moving from topic to topic in an orderly fashion as outlined by the meeting agenda book. In general, the review topics generated little or no discussion by the members even when prompted by the chairman. The entire meeting lasted about 30 minutes. The inspector plans to attend future NORB meetings, inspect the internal processes, and examine NORB member involvement in order to better understand how the licensee implements the requirements of TS 6.5.2.

4.4 Spent Fuel Pool Survey

During the week of March 4, the NRR Senior Project Manager for FNP was onsite to perform a detailed survey of issues related to the SFP and its cooling systems. The results of this survey will be evaluated and documented by NRR at a later date. The resident inspectors provided some assistance to the NRR Senior Project Manager during his visit.

A potential FSAR discrepancy was identified by an inspector regarding normal versus emergency full-core offloads. Section 9.1.3 and Table 9.1.1. of the FSAR specifically describe a normal full-core offload as 180 hours after shutdown and an emergency full-core offload as 150 hours after shutdown. Full-core offloads are routinely performed at FNP during scheduled refueling outages. And although the licensee's planning department was well aware of TS 3.9.3 which limits irradiated fuel movement to 100 hours after shutdown, it was not aware of the FSAR distinction between emergency and normal full-core offload. Also there were no administrative controls in place to preclude conducting full-core offloads in a manner that deviates from the FSAR. This concern was communicated to the outage planning supervisor and plant management. In response to this concern, TCNs were issued to applicable UOPs to limit the movement of irradiated fuel for full-core offloads to greater than 180 hours after shutdown. A licensee review of past refueling outages confirmed that even though fuel movement in a couple of recent cases had been scheduled earlier than 180 hours after shutdown, that the FSAR assumption of Table 9.1.1 for an entire core offload in the SFP at 180 hours after shutdown had not been exceeded.

5.0 PLANT SUPPORT (71750, AND 82302)

5.1 Fire Protection

During normal tours, inspectors routinely examined aspects of the plant FP Program (e.g., transient fire loads, flammable materials storage, fire brigade readiness, ignition source/risk reduction efforts and FP features). In general, plant personnel and equipment conformed with the established FP Program. Several minor problems were discussed and resolved with the onsite Fire Marshall.

The Unit 1 Containment Fire Detection System (1A-22) remained inoperable as previously discussed in IR 50-348/95-20. Efforts to troubleshoot the system inside containment during the Unit 1 ramp down to 15% in February were not successful. An inspector has confirmed that the licensee's current compensatory measures for monitoring containment air temperatures are consistent with the Fire Protection Program described in the FSAR and the original TS 3.3.3.9 (which has since been deleted from TS as part of a line item improvement license amendment). The licensee plans to repair 1A-22 during the earliest possible opportunity which is during the upcoming April 20 midcycle outage for Unit 1. A possible design change to add a smoke detector in the mini-purge line is also being considered.

5.2 Security

During routine inspection activities, inspectors verified that security program plans were being properly implemented. This was evidenced by: proper display of picture badges; appropriate key carding of vital area doors (except as noted below); adequate stationing/tours of security personnel; proper searching of packages/personnel at the Primary Access Point; and adequacy of compensatory measures during disablement of vital area barriers. Licensee activities observed during the inspection period appeared to be adequate to ensure proper plant physical protection. Guards were observed to be alert and attentive while stationed at disabled doors, and responded promptly to open door alarms. Posted positions were manned with frequent relief.

5.3 Health Physics

Inspectors routinely examined postings and surveys of radiological areas and labelling of radioactive materials in the RCA. Work activities of plant personnel in the RCA were observed to adhere to established administrative guidelines for radiation protection and ALARA work practices. Effluent and environmental radiation monitors were monitored on a routine basis for any significant changes in radiological conditions or indications of uncontrolled releases. No significant findings were identified. Health physics technicians maintained positive control over the RCA and provided good support of Unit 1 and 2 steady-state operations and maintenance activities. Health physics management continued to keep the resident staff well informed of potential radiological issues. The latest revision of NRC Form 3 dated January 1996 was promptly posted throughout the plant.

5.4 Emergency Plan Drill

On February 28, a resident inspector observed one of the licensee's routine quarterly emergency drills. Plant emergency response personnel arrived in a timely manner. The accident scenario was challenging. The relatively new Operations Manager acted as the Emergency Director for the first time doing a yeoman job. As in past drills, the Emergency Planning staff personnel and monitors interacted well with the crew that were acting out the scenario providing a good learning and refresher situation. The licensee responded well to the inspector's concerns and questions. Although there was some initial minor problems with telephone communications, they were handled in a promt business-like manner. The inspector performed checks of licensee provided data retrival system and performed a satisfactory phone check.

6.0 Other NRC Personnel Onsite

On March 5 through 7, 1996, Mr. Byron Siegel, Senior Project Manager for NRR, was onsite to conduct a detailed survey of the SFP in light of specific issues that arose from recent problems at Millstone.

On March 19 and 20, 1996, Mr. Pierce Skinner, Branch Chief, Division of Reactor Projects, Region II, was onsite to meet with the resident inspectors and tour the facility.

7.0 Review Of FSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors:

a. Emergency core offload versus normal core offload (see Section 4.4);

b. Seismic Instrumentation (see Section 2.6); and

c. Control of Tavg - Section 7.7.1 of the FSAR directly implies that Tavg is controlled by rod movement. Yet plant practice is to operate the core ARO and control Tavg by diluting or borating the RCS. This is considered an extremely minor discrepancy since FSAR Section 9.3.4 states the CVCS is used to compensate for fuel burnup.

8.0 EXIT INTERVIEW

The inspection scope and findings were summarized on March 21, 1996, by the SRI with plant personnel and management indicated in Section 1.0. Interim exits were previously held on February 9 (Kellogg), February 16 (Crowley), March 1 (Maxwell), and March 8 (Kleinsorge, et al.). During the final exit meeting the SRI described the areas inspected and discussed the inspection results as detailed in this report. SNC management at FNP acknowledged these findings and did not identify as proprietary any material provided to or reviewed by the inspectors nor did they express any dissenting comments. The status of all inspection report items discussed in this report are as follows:

TYPE	ITEM NUMBER	STATUS	DESCRIPTION AND REFERENCE
LER	50-364/94-02	Closed	Service Water Pumps' Lube and Cooling Valves Surveillance Not Performed (Section 3.4.a)
LER	50-348/95-03	Closed	Potential For Loss of Automatic Engineered Safety Features Actuation (Section 3.4.b)
LER	50-348/95-04	Closed	Actuation of Engineered Safety Feature Equipment Due to Inadvertent Contact While Installing a Test Lead (Section 3.4.c)
LER	50-364/95-04	Closed	Reactor Coolant Pump Bus Undervoltage Relays Dropout Setpoints Outside Operability Tolerance (Section 3.4.d)
LER	50-364/95-07	Closed	Reactor Trip Due To Turbine Trip Caused By Overfilling Of The 2C Steam Generator (Section 2.14.a)
IFI	50-348, 364/95-20-01	Closed	Decrease in Licensee's Number of Root Cause Determinations (Section 2.14.b)
IFI	50-348, 364/96-02-01	Open	Seismic Monitoring System FSAR Update (Section 2.6)
IFI	50-348, 364/96-02-02	Open	HSDP Test Failures (Section 3.3.c)
IFI	50-348, 364/96-02-03	Open	Pre-action Sprinkler System Failures (Section 3.3.d)

IFI	50-364/96-02-04	Open	Computational Errors Result In Inadequate MSR Drain Tank Manway Torque Values (Section 4.1)

9.0 ACRONYMS AND ABBREVIATIONS

ACP - Administrative Control Procedure
ALARA - As Low As Reasonably Achievable
AOP - Abnormal Operating Procedure
AP - Administrative Procedure
ARO - All Rods Out
ARP - Annunciator Response Procedure
ASME - American Society of Mechanical Engineers
BOP - Balance of Plant
CREVS - Control Room Emergency Ventilation System
CVCS - Chemical and Volume Control System
DC - Direct Current
DEHC - Digital Electro-Hydraulic (Control)
DG - Diesel Generator - same as EDG
DR - Deficiency Report
DRPI - Digital Rod Position Indication
DRS - Division of Reactor Safety
EDG - Emergency Diesel Generator
EGM - Electro-Mechanical Governor Module
EHC - Electrohydraulic Control
elev. - Elevation
EM - Electrical Maintenance [Department]
EMP - Electrical Maintenance Procedure
EPB - Emergency Power Board
EPC - Engineering Project Council
ESF - Engineered Safety Features
ESF - Engineered Safety Features Actuation System
FIN - Fix It Now Team
FNP - Farley Nuclear Plant
FNPIR - Farley Nuclear Plant Incident Report
FP - Fire Protection
FRV - Feed Regulation Valve (Main Feedwater)
FSAR - Final Safety Analysis Report
FSP - Fire Protection Surveillance Procedure
GMP - General Maintenance Procedure
gpm - Gallons Per Minute
GV - Governor Valve
HHSI - High-Head Safety Injection
HP - High Pressure (steam)
HSDP - Hot Shut Down Panel
HVAC - Heating, Ventilation, and Air Conditioning
I&C - Instrumentation and Control [Department]
IAW - In Accordance With
IFI - Inspector Followup Item
IMP - Instrument Maintenance Procedure
IR - Inspection Report
ISI - Inservice Inspection

KV - Kilo - Volt
lb - pound
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LP - Low Pressure (steam)
LOSP - Loss of Off Site Power
MCB - Main Control Board
MCR - Main Control Room
MDAFW - Motor-driven Auxiliary Feedwater
MFW - Main Feedwater
Moog - Servo Valve Vendor
MOV - Motor-Operated Valve
MP - Maintenance Procedure
MSIV - Main Steam Isolation Valves
MSR - Moisture Separator Reheater
MSVR - Main Steam Valve Room
M&TE - Maintenance and Test Equipment
MTG - Main Turbine Generator
NORB - Nuclear Operations Review Board
NRC - U.S. Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation [U.S. NRC]
NSSS - Nuclear Steam Supply System
PASS - Post Accident Sampling System
PM - Preventive Maintenance
PMD - Plant Modification and Design [Department]
PMT - Post Maintenance Test
PRF - Penetration Room Filtration
QA - Quality Assurance
QC - Quality Control
RCA - Radiological Control Area
RCP - Reactor Coolant Pump
RCP - Radiological Control Procedure
RCS - Reactor Coolant System
REA - Request For Engineering Assistance
RGSC - Ramp Generator Signal Converter
RHR - Residual Heat Removal
RP - Radiation Protection
rpm - revolutions per minute
RO - Reactor Operator
RTD - Resistive Temperature Detector
RWP - Radiation Work Permit
RWST - refueling Water Storage Tank
RX - Reactor
SAER - Safety Audit and Engineering Review
SBO - Station Blackout
SCS - Southern Company Services
SALP - Systematic Assessment of Licensee Performance
SFO - Shift Foreman - Operating
SFP - Spent Fuel Pool
SG - Steam Generator
SGBD - Steam Generator Blowdown
SGFP - Steam Generator Feed Pump

SGWL - SG Water Level
SI - Safety Injection
SJAE - Steam Jet Air Ejector
SNC - Southern Nuclear Operating Company
SO - System Operator
SOP - Standard Operating Procedure
SR - Safety Related
SS - Shift Supervisor
SSPS - Solid State Protection System
STP - Surveillance Test Procedure
SWS - Service Water System
SWIS - Service Water Intake Structure
Tave - Average Temperature (RCS) or Tavg
TB - Turbine Building
TCN - Temporary Change Notice
TDAFW (P) - Turbine-driven Auxiliary Feedwater (Pump)
TO - Tag Order
TS - Technical Specifications
TSLB - Control Room Board Indication Light
UO - Unit Operator (licensed)
UV - Undervoltage
UOP - Unit Operating Procedure
VIO - Notice of Violation
WA - Work Authorization (very similar to below)
WO - Work Order