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

Report Nos.: 50-348/93-28 and 50-364/93-28

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 1 and 2

Inspection Conducted: October 22 - November 22, 1993

Inspectors: F. Cantrell for 12/14/93
Thierry M. Ross, Senior Resident Inspector Date Signed

F. Cantrell for 12/14/93
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SUMMARY

Scope:

This routine, resident inspection involved on-site inspection of licensee operations, maintenance/surveillance activities, Unit 2 refueling activities, and a continuing evaluation of licensee self-assessment. Deep backshifts were performed October 30 and 31, and, November 3, 4, 11, and 12.

Results:

Operations

Unit 2 refueling operations began October 29, paragraph 3.a. Generally, the refueling operations were conducted by trained, knowledgeable personnel in a methodical and orderly fashion with few equipment problems. One fuel assembly was loaded into an incorrect position as a result of an incorrect procedure, paragraph 3.b.

As a result of a number of low consequence mistakes, previously licensed senior managers were assigned to each shift in a support/coaching role. This initiative appeared to have had positive effect on the outage. Unit 2 entered mid-loop RCS operations two times without any problems and with good control over the evolutions, paragraph 3.d. and 3.e. One non-cited violation (NCV) was identified.

Maintenance and Surveillance

As a result of inadequately prepared instructions, packing was not properly installed in the Unit 2 residual heat removal system loop suction valves, paragraph 4.d. An NCV was identified. During "hydro" testing, one of the new "SB" steam generator tube plugs leaked. This required redraining the S/G to effect repairs, paragraph 4.f. An inspector identified problem (URI 93-22-01) involving scaffold installation in the vicinity of safety-related equipment was identified as a noncited violation, paragraph 4.c. FNP personnel were aggressive in the identification and resolution of a hinge pin problem with the "1C" service water pump breaker, paragraph 4.b.

A concern about the use of the correct revision of procedure STP-40.0, "Safety Injection with Loss of Offsite Power Test" was identified, paragraph 5.c. This was identified as an unresolved item.

Engineering and Technical Support

Engineering activities were observed in support of plant testing and support. Independent Safety Engineering Group activities and functions were reviewed. In general, their activities met NRC requirements and made a positive contribution to the safe operation of FNP, paragraph 5.a. and 5.b.

Plant Support

Fire protection activities were observed to be adequate, paragraph 6.

In summary, three non-cited violations and one unresolved item were identified. Except as noted, no other violations or deviations were identified. Results of this inspection indicate that actions by management, operations maintenance were adequate to assure safe operation of the plant.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *W. Bayne, Supervisor Safety Audit and Engineering Review
   *C. Buck, Technical Manager
   P. Crone, Superintendent, Operations Support
   L. Enfinger, Administrative Manager
   *R. Hill, General Manager - Farley Nuclear Plant
   R. Marlow, Technical Supervisor
   M. Mitchell, Superintendent, Health Physics and Radwaste
   C. Nesbitt, Operations Manager
   J. Osterholtz, Assistant General Manager - Plant Support
   J. Powell, Unit Supervisor - Plant Operations
   *L. Stinson, Assistant General Manager - Plant Operations
   *J. Thomas, Maintenance Manager
   *B. Yance, Systems Performance Manager

   *Attended the exit meeting

   Other licensee employees contacted included, technicians, operations personnel, security, maintenance, I&C and office personnel.

   Acronyms used throughout this report are listed in the last paragraph.

2. Plant Status

   a. Unit 1 Status

      Unit 1 operated at approximately 100 percent power for most of the reporting period.

   b. Unit 2 Status

      Unit 2 was shutdown all of the inspection period for a refueling outage. The return to power from the outage, November 17, was delayed due to steam generator (S/G) tube plugging problems, paragraph 4.f.

   c. NRC/Licensee Meetings and Inspections

      During the week of October 25, Region II, Division of Reactor Safety (DRS) engineering personnel performed an EDSFI follow-up inspection. (Report 50-348,364/93-27).

      During the week of November 1, Region II DRS engineering personnel continued inspections of non-destructive examinations and licensee in-service inspection (ISI) activities (Report 50-348,364/93-25).

      On November 17, a public enforcement conference was held in Atlanta, in the region office regarding Report 50-348,364/93-26.

3. Operational Safety Verification (71707) and Refueling (60710)

The inspectors conducted routine tours to verify license requirements are being met. The inspection tours included review of site documentation and interviews with plant personnel.

a. Core Reload - Unit 2 (60710)

On October 29, the licensee commenced refueling operations of Unit 2 in accordance with FP-APR-R9, "Farley Unit 2 Nuclear power Plant Cycle IX Refueling Procedure." The inspectors monitored licensee and NSSS/fuel vendor activities in the control room, spent fuel pool (SFP), and reactor cavity areas during core reload. At FNP, the vendor was contracted to operate fuel transfer equipment and conduct all fuel movements under the direct observation of licensee personnel. A licensed senior reactor operator (SRO) was stationed in the containment refueling area boundary (CRAB) during all core alterations. The refueling SRO was observed to be on the refueling bridge most of the time during core alterations. Unit 2 core reload was completed on November 2, 1993, with only one significant incident (discussed in the next section).

The inspectors reviewed FP-APR-R9, verified accomplishment of certain prerequisite initial conditions, confirmed procedural precautions were being adhered to, and observed the execution of the refueling procedure by the licensee and vendor for selected fuel movements. In general, personnel and equipment involved with refueling activities performed as expected and in accordance with applicable plant procedures, in particular FP-APR-R9. On a whole, the entire refueling evolution was conducted by trained, knowledgeable personnel in a methodical and orderly fashion with little or no equipment problems.

An inspector identified some minor findings regarding the cleanliness of the CRAB and the inventory of foreign material therein. At FNP, the Health physics organization is responsible for controlling personnel and equipment entry into the CRAB. The inspector discussed these findings with licensee management who promptly and effectively resolved them.

b. Misplaced Fuel Assembly - Unit 2 (60710)

On November 1, during Unit 2 refueling operations, the licensee's vendor discovered that a fuel assembly had been loaded into an incorrect core location. The licensee immediately secured all refueling activities and began an investigation.

During performance of step 134 of the Unit 2 core reload sequence of refueling procedure FNP-APR-R9, a member of the vendor's refueling team that was coordinating refueling activities from the control room noted a discrepancy between the fuel handling data sheet and the refuel or fuel status board (core map). At step 134, the fuel handling data sheet indicated that fuel assembly numbered 2M25 was to be moved from SFP location X-4 to reactor core location M-11. However, the magnetic strip designator being moved from SFP location X-4 to core location M-11 on the control room fuel status board indicated 2M26. The fuel status board also indicated that 2M25 had already been loaded into core location D-5 (during step 72).

The licensee's investigation determined that the fuel vendor had made an error in developing the core reload sequence that went undiscovered during subsequent procedure reviews by the licensee's reactor engineering (RE) group and the PORC. Fuel assembly numbers 2M25 and 2M26 were switched by the vendor on the fuel handling data sheet during the development of a TCN to FNP-APR-R9 to correct other related discrepancies identified by licensee reactor engineers. The investigation also recognized that an earlier opportunity to discover the error at step 72 had been missed. The error was discovered prior to completion of fuel load and final core fuel position verification.

The licensee's initial corrective actions included: (1) re-review of the entire core reload sequence by reactor engineering and the SAER group; (2) video map of partially loaded core, reviewed by reactor engineering and SAER; (3) the generation of a safety evaluation and a procedure change was made to allow leaving fuel assemblies 2M25 and 2M26 in their switched core locations; and (4) complete and verify final core map by video. An inspector monitored portions of the licensee's investigation, examined the partial core map video with SAER, reviewed and discussed proposed corrective actions with licensee management, and attended the PORC meeting approving those followup actions. Unit 2 refueling operations were resumed late that night on November 1, 1993.

Additional long-term corrective actions planned by the licensee and the fuel vendor to prevent recurrence are paraphrased as follows: (1) future core reload sequences shall be reviewed step by step by the fuel vendor to confirm resultant reactor core configuration prior to issuance to FNP; (2) the licensee's Technical Group (which contains the RE group) shall conduct a comprehensive review of the entire refueling procedure package received from the vendor prior to implementation; (3) fuel status board operators shall verify magnetic indicators during fuel movements; and (4) fuel movement sequences shall be "stepped through" on the fuel status board prior to any actual fuel movement (e.g., unload, reload, insert changeouts). These and the aforementioned corrective actions are documented in incident report 2-93-258. The inspectors will verify the licensee's implementation of long-term corrective action during the upcoming Unit 1 refueling outage. This is an inspector followup item (IFI) 50-364/93-28-05, "Fuel assembly mislocation - corrective actions." Due to the event having no safety impact and the prompt and extensive corrective actions, no enforcement action was warranted. However, the facts of this event demonstrate that the licensee procedure reviews were not sufficient to detect the error.

c. Assignment of a Temporary Operations Shift Manager - Unit 2

During the inspection period the following licensee-identified events occurred:

1) On October 28, during performance of motor operated valve differential pressure testing, the 2B charging pump was operated for about 90 minutes, in a mini-flow alignment, with component cooling water (CCW) to the seal water heat exchanger isolated. Seal water heat exchanger outlet temperature reached about 290 degrees F. The standard operating procedure for starting of the charging pump, was not properly consulted prior to starting of the pump. Implementation of this procedure would have checked the valve lineup of the seal water heat exchanger.

2) On October 29, during recovery operations for the above event, several of the seal water heat exchanger valves were repaired. Due to improper valve alignment after the repairs, an isolation valve on the seal return from the heat exchanger was left closed during system restart. This alignment caused the seal water (system) relief valve to lift. This misalignment was caught prior to pump or relief valve damage occurring. The charging pump was not in service at that time.

3) On October 30, the unit 4160V bus 2H supply breaker, DF-13 was opened in order to perform response time testing. Prior to the breaker opening, the unit shift supervisors and operators discussed and then assumed that the 1C diesel generator (D/G) would not start, even though this bus would be de-energized. However, they failed to look at the associated drawings to verify their assumptions. When the tie-breaker DF-13 was opened, the 1C D/G auto started. Outside of the EDG start, no other protective devices started or were challenged. The EDG was still available for its safety function.

On October 30, in light of these and a previously reported October 5 SFP heat exchanger event, (see report 50-348,364/93-26, paragraph 2.c.), the FNP general manager assigned licensed or previously licensed senior plant management personnel to each shift. The purpose of the assignment was [illegible] proper coordination of shift supervisor activities during the outage, specifically those activities involving "release of work". The managers were not placed on-shift to approve work items, but to discuss with operations personnel, possible consequences of work being released. They were also tasked with attempting to gain a better understanding of what was required of the shift supervisors during outages and what might be changed to identify and reduce personnel errors. For the remainder of the inspection period (approximately three weeks) with management-on-shift implemented, no other problems of the same relevance as above or greater were observed.

The above three items were identified as a single non-cited violation (NCV) 50-364/93-28-01, "Inadequate shift supervisor review prior to release of work". This violation will not be subject tc enforcement action because the licensee's efforts in identifying and correcting the violation meets criteria specified in Section VII.B of the Enforcement Policy.

d. Mid-Loop Operation on November 12th - Unit 2 (TI 2515/103)

On November 12, operators reduced the RCS inventory of Unit 2 and established mid-loop level conditions for the routine removal of SG nozzle dams. This was the second planned mid-loop conditions established during the Unit 2 refueling outage. During preparations to place Unit 2 in mid-loop operation, the inspectors examined personnel and plant readiness. An inspector also monitored the licensee's activities during draindown of the RCS to mid-loop.

Unit 2 was in a fully "fueled" condition while in mid-loop operation. Throughout this evolution the licensee exhibited great sensitivity to the potential risks of mid-loop operation. Unit 2 was in mid-loop for only three days.

The inspectors reviewed the following documents:

- 2-UOP-4.3, "Mid-Loop Operations"
- U2-RF9 Mid-Loop Compensatory Measures
- 0-UOP-4.1, Appendix 1, "Shutdown Safety Assessment"

The inspectors observed and/or verified accomplishment of the following:

- Procedural prerequisites in place, such as availability of two injection flow paths, an operable charging pump, and ability to borate.
- Administrative controls established for shift manning, training, communication requirements, and radiation monitoring.
- Shift supervisor (SS) briefing of entire shift complement on precautions and limitations associated with mid-loop operations, and applicable abnormal operating procedures.

- Training on mid-loop related activities and proceoures during the last requalification cycle.

- Two independent, continuous temperature indicators (i.e., core exit thermocouples) in operation.

- Four diverse means of RCS level indication in operation (only two required) - 1) standpipe ("tygon tube"), 2) temporary level indicator off the A reactor coolant loop flow transmitter, 3) normal level indicator (LT-2965) off the B reactor coolant loop, 4) ultrasonic level monitoring system.

The licensee's procedures for controlling reduced inventory operations contained specific precautions regarding actions which might adversely impact the ability to maintain sufficient core cooling. Furthermore, the licensee issued a directive on mid-loop compensatory measures dated November 11, 1993, which precluded work activities on critical systems, including electrical power supplies. The inspectors determined that the licensee's preparations were adequate for conducting mid-loop operations in a safe and controlled manner.

An inspector watched plant operators reduce RCS level to 123 feet 4 inches ± 1 inch to establish and maintain mid-loop conditions. This evolution was conducted without incident in an orderly and methodical fashion in accordance with plant procedures. During mid-loop operations, at least two means of adding inventory to the RCS were available. In addition to an RHR pump, one of three charging pumps was available and could be aligned to borate the RCS. Four offsite sources of power and four EDGs were available and emphasis had been placed on the availability of vital power.

UOP-4.1, Appendix 1, Shutdown Safety Assessment, was used to provide a safety assessment, on a shifty basis, of plant conditions when in Mode 5. This procedure assessed power availability, reactivity control, core cooling, containment integrity, and RCS inventory and integrity conditions throughout the period of mid-loop operation.

e. Mid-Loop Operation on November 19th - Unit 2 (TI 2515/103)

On November 17, the licensee began preparations for an unplanned return to RCS mid-loop operations. The above reviews were repeated.

The licensee discovered that the 2B SG which had been reworked extensively by a vendor during the outage had inleakage from the RCS. During Unit 2 return to service it was discovered that boron and radioactive contaminants were appearing on the secondary side. The plant was at less than 180 degrees F and around 350 psig.

On the morning of November 19, the inspectors observed the RCS level reduction into mid-loop. This period of observation included a shift turnover at approximately 124 feet which was slightly above their target level of 123.5 ft. The on-shift operators made a conscious effort to stop level reduction and stabilize the plant until the turnover was completed. Once the turnover was completed, the on-coming shift was deliberate in their actions prior to and during the resumption in level reduction.

The level indications were tracking within approximately 1.5 inches. When the operators halted the drain down, the levels tracked evenly with little overshoot (i.e., no unanticipated level variance or instrument oscillations). Prior to and at the minimum level, the inservice RHR pump did not demonstrate vortexing or related pumping problems.

With the exception of one NCV, no other violations or deviations were identified in this area. Results of inspections in the operations area indicate that operations personnel conducted assigned activities in accordance with applicable procedures.

4. Monthly Maintenance Observation (62703)

The inspectors reviewed various licensee preventative and corrective maintenance activities, to determine conformance with facility procedures, work requests and NRC regulatory requirements.

a. Portions of the following maintenance activities were observed:

1) MWR-275919; 2B EDG B air compressor (A/C) - Repair air leak

An air leak was found around the threaded portion of an unloader valve fitting. The inspector observed that the fitting was removed/cleaned, and a "loc-tite" sealant was applied to the fitting threads before reinstallation. A leak test was performed and work performed was satisfactory and in accordance with guidance contained in the MWR and A/C technical manual.

2) MWR-258858; 2A MSR manway cover - Repair leaking seal surface

The original pump packing had developed a leak and Furmanite had been applied during the previous fuel cycle operation. The inspector observed that a proper replacement gasket was obtained, the old gasket and Furmanite were removed, seating surfaces were machined/refurbished, and the new gasket and cover were reinstalled. An inspection of the area is to beperformed to determine success/failure at normal operating pressures/temperatures. Work accomplished was in accordance with the MWR.

3) MWR-253439; Machining of the 2C MSIV

The inspector observed the satisfactory machining of the silver seal fit area on the 2C MSIV. The machine setup and machining operations were well controlled. The special machine used for the job behaved properly without chatter or any cutting problems. The contractors involved were very professional and business-like during the operation.

4) MWR-282119; 86 Lockout relay replacement on the 2B CCW pump breaker DG-05

As with most safety-related breakers in this plant, the 2B CCW DG 05 breaker was protected by overcurrent relays that provided signal to the 86 relay. The 86 relay is a slave relay during electrical power transients that opens the 4160 Volt power breaker to protect the pump motor from damage.

The 2B CCW breaker 86 relay had a problem resetting prior to the performance of a section of response time testing with a simulated loss of offsite power. The inspector was told that the replaced relay had been mechanically hard to operate.

The inspector observed the installation of the wire harness on the new 86 relay and its continuity testing of the new relay while installed. The electricians involved were conscientious in the wire re-attachment and even though they were to have a second individual check their work, they caught some minor errors and corrected them in-process. The were also very deliberate in their routing of the harness to the relay in an attempt to maintain good electrical isolation. The electricians restored breaker cabinet integrity and notified security of their completion at close of the two work phases (two separate breaker cabinet entries) that the inspector observed.

The inspector discussed post maintenance testing with the electrical department staff. The department's accompanying procurement paper indicated that the relay had passed its vendor's tests (certificates of conformance). The staff had not bench tested the replacement relay based on the vendor records; however, additional testing was performed on the relay as an enhancement to this phase of functional testing. A signal was supplied from the overcurrent relay to the 86 relay and the 86 relay did open to trip the DG 05 breaker as required.

b. Inspection of (4160V Breaker) Stop Bolts and Allen Set Screws (MWR-282234)

The licensee discovered that an allen setscrew had backed out of a Unit 2 4160 Volt breaker for the 1C SW pump. The set screw held a pin in the breaker's linkage that closed the breaker. The hinge-like pin it retained vibrated out of position to the point that it interfered with breaker closure. The linkage was damaged and would not close. This breaker was on the swing pump and had a much higher cycle frequency than other breakers of the same service and type. The licensee was quick to grasp the implications of the problem. Work orders were written to check on similar breakers that received automatic SI signals or that were swing breakers.

The 2B CCW pump breaker was discovered to have a slightly loose set screw. With the inspector present, the screw was not found to be sufficiently loose to affect the breaker's operation, but the set screw was not seated firmly on the hinge pin. The pin had not moved laterally at this point. From the inspection it was apparent that no other forces outside of jarring force of breaker closure, and the rotation of the linkage as it swung through its arc of movement, would make the hinge pin move laterally. Like the 1C SW pump breaker, the 2B CCW pump breaker was a swing breaker between electrical trains. The screw was tighten to a torque value recommended by the breaker vendor. "Lock-tite" was applied to its threads to prevent future looseness. (The vendor's manual did not list a torque value for the screw as such it was not apparent that this was a critical value.)

Examination of the affected breaker population was in progress at the end of this inspection period. On Unit 2, operations could only release breakers that would support plant operations. Unit 1 breakers have not been inspected. The inspector reviewed three additional MWRs (282233, 35, and 36) on similar breakers that did not have loose parts. The inspectors will review the breaker inspection results for generic applicability. With the type of failure seen only once, and the licensee's response to date, there does not appear to be any significant safety concerns. The inspectors will monitor this corrective maintenance.

c. Incomplete Scaffold Permits - Unit 2

In IR 93-22, an inspector identified an unresolved item (URI 93-22-01) regarding scaffold installations in the vicinity of safety-related equipment. The inspector discovered that scaffold permits for a number of scaffolds in the Unit 2 containment, auxiliary building, and EDG building were incomplete. In particular, the responsible job foreman/supervisor had failed to sign the applicable scaffolding permit to approve the scaffolds for work and yet these scaffolds were being used. General Maintenance Procedure FNP-0-GMP-60, "General Guidelines And Precautions For

Erecting Scaffolding," specifically requires job foremen/ supervisor approval of scaffolds in vicinity of safety-related equipment and prior to any work being performed from the scaffold. In response to the inspector's finding, the licensee conducted a walkdown of all active scaffolds to locate and correct any deficient permits, and issued a memorandum to applicable managers and supervisors requesting they insure responsible personnel are aware of and comply with the requirements of FNP-0-GMP-60.

Shortly after the licensee had completed the aforementioned corrective actions, the inspector examined several scaffolds in the auxiliary building and Unit 2 containment. On this tour, the inspector identified only one incomplete scaffold permit in the Unit 2 containment (i.e., walkway scaffold underneath MS lines exiting containment). This deficiency was brought to the licensee's attention and promptly corrected. Subsequent tours of the auxiliary building, Unit 2 containment, and EDG building did not identify any other deficiencies.

This item was previously identified as an unresolved item (URI) 50-364/93-22-01, Incomplete scaffold permits. This violation is now identified as an NCV 50-364/93-28-02, Incomplete scaffold permits, but will not be subject to enforcement action because the licensee's efforts in correcting the violation and the low safety significance meets criteria specified in Section VII.B of the Enforcement Policy.

d. Improperly Installed Residual Heat Removal Valve Packing- Unit 2

On October 24, the licensee identified that FNP contractor personnel followed inaccurate and poorly presented instructions and failed to properly install packing in the Unit 2 residual heat removal (RHR) system loop suction valves. At the time of discovery, the valves were not operable or released for operational use.

During post-maintenance testing of the valves, loud noises were reported, valve testing was stopped and the packing torque was readjusted. During subsequent attempts to consolidate the valve packing by stroking the valves and readjusting torque, a packing gland on one of the loop suction valves galled the valve stem.

Upon disassembly of the valve, it was discovered that the packing had not aligned itself properly and some of the packing was imbedded on the bottom and inside of the packing gland. This condition led to cocking of the packing gland and metal to metal contact of the gland to the valve stem. Although a valve vendor packing procedure and drawings had been sent to the licensee, the procedure and drawings had not been forwarded to personnel involved with the repacking work. Inadequate instructions for packing of the valves were given verbally to maintenance personnel by licensee supervisors and a valve vendor technical representative. The valve packing had not been installed in accordance with either the vendor's written instructions or per plant maintenance procedures or instructions.

Corrective actions included, discipline of personnel involved, a rewriting of the maintenance procedure for repacking of the RHR valves and reemphasis of using proper repair procedures, preferably written guidance, for any repair work.

This violation is identified as NCV 50-364/93-28-03, Improperly installed RHR valve packing and will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meets criteria specified in Section VII.B of the Enforcement Policy.

e. Loose Vent Pipe on Reactor Coolant Pump (RCP) Motor "2A" - Unit 2

On October 22, the inspectors noted that the lubrication piping leading to the 2A reactor coolant pump was repaired in a slipshod fashion, [IR 50-348,364/93-22, paragraph 3.b.(4)].

Copper piping sweat joints were loose, and in one case, the "repaired" sweat joint was simply a coating of solder spread over the piping and threaded joint. On November 17, in a letter to FNP's electrical maintenance manager, the vendor RCP coordinator noted that since this tubing is actually oil mist vent piping and since pressures experienced by this piping is minimal, all piping should be acceptable in their present condition/configuration.

The inspectors will continue to monitor performance of this pump after restart of the unit.

f. Steam Generator Tube and Plug Leak - Unit 2

One SG tube was pulled for inspection of the internal repair of an indication on the tube's wall. During the pull efforts described in report IR 50-348,364/93-25, the tube elongated and came apart inside the S/G. The affected tube was plug welded at the tube sheet. However, the remnant or section of the tube left in the S/G could not be supported internally. As a precaution, the adjacent seven tubes around the faulted tube were supported and plugged.

During restart operation, on November 16, a process monitor alarmed on the S/G blowdown system. The 2B S/G was identified based on an increase in both secondary side activity and boron concentration. The RCS was drained to mid-loop (see paragraph 3.e.) for further inspection of the steam generator .

The tube identified as the leaker had a welded plug in the tube sheet. The weld at the tube sheet was not holding. The tube plug was replaced and the licensee continued with the outage on November 21.

Other than the two NCVs, no other violations or deviations were identified in this area. The results of inspections in the maintenance area indicate that both operations and maintenance personnel conducted assigned activities in accordance with applicable procedures except as noted. Contractor and valve representatives worked together smoothly without licensee oversight on the 2C MSIV machining. The licensee was aggressive in identification and initiation of problem resolution on the 4160V breaker problem.

5. Monthly Surveillance Observation (61726)

Inspectors witnessed surveillance test activities performed on safety-related systems and components in order to verify that such activities were performed in accordance with facility procedures and NRC regulatory requirements.

a. Portions of the following surveillance activities were observed:

1) 1-STP-1.0; Shift Surveillance Requirements - Modes 1 through 4

Inspectors routinely observed operator activities while parameters were monitored, documented and evaluated.

2) 2-STP-158; RCS Pressure Isolation Valve Leak Test

The inspector watched setup and operator control leading to the testing of the hot leg injection valve test portion of this procedure. The operator involved with the co-ordination and preparation was aware of the procedural requirements and practical test details. Operations established proper conditions for the test. The test personnel were aware of the plant and the test details. The hot leg check valves tested satisfactorily. The inspector discussed the completed test results and test details with the SP engineers and personnel to determine their knowledge and understanding of the test.

3) 2-ETP-1041.2; DP Testing of 2C Containment Cooler SWS MOVs

The inspector observed portion of the test procedure 2-ETP-1041.2, paragraph 4.2.1, that examined the differential pressure testing of valve Q2P16MOV3024C, SW to CCW Heat exchanger header isolation. This valve had galled previously during testing and had been repaired. Operations supported this test well. The operator in control and supporting MOV personnel got permission to start an additional service water pump to supply sufficient pressure for the test. The operator was attentive to test details and accurate test completion. The MOV personnel were positive in their test role. The valve passed the test with low actual MOV actuator thrust values and acceptable stroke times.

4) 1-STP-22.1; MDAFW Pump 1A Quarterly Inservice Test

The test was performed satisfactory and the pump operated correctly. The operators involved with the test knew where the valves were located that required manipulation, and the licensed operator was generally familiar with the test procedure and what was required to complete the test. Although the operators knew the details of the procedure, they did follow the details of the written instruction which limited potential problems that could possibly stem from working from memory only. Mechanical maintenance was present to take vibrational measurements for the maintenance engineering support group (MESG) that trends pump degradation. These personnel were familiar with the tests and the equipment that they were using.

5) 2-IMP-228.2; NIS Flux Deviation Channel N50 Calibration

The inspector observed test equipment installation and calibration of the Upper Section Deviation, Lower Section Deviation, and All Channels Below 50 percent Full Power alarm trips for the Unit 2 NIS Detector Current Comparator. Both the Lower and Upper Deviation trip setpoints were found to be out of tolerance. The responsible I&C technician adjusted these setpoints until they were within the tolerance prescribed by procedure. The All Channels Below 50 percent Full Power trips were found in tolerance. Test equipment used during this activity were within calibration. The I&C technician was well versed with this particular surveillance procedure and had no difficulty in performing all required steps.

b. Snubber Functional Testing (2-STP-610.1)

Functional testing of safety-related snubbers is required every 18 months. TS SR 4.7.9.d., e. and f. prescribe the frequency, sample size and acceptance criteria for conducting functional tests of hydraulic and mechanical snubbers. During the Unit 2 outage the licensee and its contractor tested 220 snubbers. Although the initial sample size of snubbers to be tested was only 88, this population was subsequently expanded to cover an additional 132 snubbers due to identified failures.

A total of 14 snubber failures were discovered by the licensee during the Unit 2 functional testing program. These snubber failures came from the following sample groups:

- Original sample - 8 failures
- Expanded sample - 1 failure
- Retest group - 1 failure
- Same design with same defect - 4 failures

An inspector interviewed the responsible test director and his management regarding implementation of the FNP snubber test program for addressing test failures and concluded that these failures were dispositioned appropriately for Unit 2. Furthermore, expansions of the sample size were conducted in accordance with TS requirements and plant procedures. However, with regard to the snubber failures involving the same design and failure mechanism, the inspector expressed concern that the identified failures may have generic implications. All four of these snubbers were mechanical snubbers manufactured by Pacific Scientific Associates (PSA) and used in high temperature environments (i.e., SG blowdown and the pressurizer). Apparently, extended exposure to elevated temperatures adversely effected the snubber's internal lubrication.

The licensee indicated that this was a relatively new and emerging issue and has been brought to the attention of PSA and the Snubber Utility Group (SNUG). Region II, Division of Reactor Safety, along with the Office of Nuclear Reactor Regulation, are also pursuing this issue for any potential generic safety consequences. The inspector also observed the functional testing of two ITT-Grinnell hydraulic snubbers (Serial numbers 19201 and 19206) by the licensee's contractor in accordance with FNP-2-STP-610.1, Snubber Functional Testing, and FNP-0-MP-65.4, Onsite Testing and Rebuilding of Snubbers by Vendor.

Both snubbers were found to meet the "as found" acceptance criteria for lockup velocity and bleed rate when tested in the tension and compression directions. However, both snubbers required adjustment to meet the more restrictive "as left" acceptance criteria. The inspector verified that the test equipment being used was in calibration and that each snubber was being controlled by an approved MWR. Functional testing activities and snubber adjustments observed by the inspector were performed in accordance with applicable procedures by experienced and knowledgeable personnel.

c. Safety Injection with Loss of Offsite Power Test (2-STP-40.0)

On November 4, the licensee performed FNP-2-STP-40.0, Safety Injection with Loss of Offsite Power Test, on Unit 2. The principal purpose of this comprehensive, integrated test was to confirm the operability of onsite emergency power systems, containment phase A isolation system, and emergency core cooling systems (ECCS) check valves during an actual Safety Injection (SI) coincident with a loss of offsite power (LOSP). An inspector reviewed the licensee's execution of the official test procedure and independently verified a selected number of the initial conditions. In addition, the inspector attended a pre-test briefing of test personnel and the shift crew by the responsible test engineer. During the briefing, particular attention was focused on the importance, complexity, infrequent nature, precautions, and limitations of this test.

The inspector observed licensee performance and the Unit 2 response during the test. Following completion of the SI/LOSP test, the inspector concluded that, in general, plant equipment and system response met established acceptance criteria and personnel performance conformed with procedural instructions. However, the inspector noted the following exceptions: (1) two valves (Q2E21HV8149B and Q2P15HV3104) were still under clearance control at the beginning of the test, (2) response times for several components were not captured due to test equipment difficulties, (3) containment purge supply fan exhaust damper showed dual indication, (4) RHR to RCS hot leg flow acceptance criteria was not met, (5) procedural step 5.37.9 was not followed properly, and (6) the controlled copy of FNP-2-STP-40.0 in the control room did not contain the latest procedure revision (i.e., Revision 21 dated November 1, 1993).

The first three exceptions were subjected to limited scope SI/LOSP retests. Exception (4) involved the acceptance criteria for RHR to RCS hot leg flow to confirm ECCS check valve operation. During the SI/LOSP test RHR flow only reached 3825 gallons per minute vice the required 3981 gpm of procedure step 5.37.5. Subsequent vendor calculation documented by letter dated November 16, 1993, determined the measured RHR flowrate was acceptable. In the case of exception (5), the test engineer and reactor operator misread the procedural step and inadvertently misaligned the RHR system. Their error became obvious a minute or two later, when they attempted to reestablish flow from the 2A RHR to the RCS cold leg. The misalignment was promptly corrected with no adverse effects on system operation or plant safety. As for exception (6), the inspector observed the shift supervisor and plant operators perform numerous steps during the SI/LOSP using an out of date version of 2-STP-40.0. This issue is considered an unresolved item (URI) 50-364/93-28-04 "Use of an out-of-date plant surveillance procedure for testing", pending licensee review/corrective actions.

No violations and no deviations were identified in this area. The results of inspections in this surveillance area indicate that personnel conducted assigned activities in accordance with applicable procedures except as noted. Only one of the many tests observed had a problem.

6. Fire Protection/Prevention Program (64704)

The inspectors observed control of combustibles, fire hazards, fire barrier breaches, and general housekeeping this inspection period with no adverse items noted. A number of barrier breaches were in place during this period because of the on-going Unit 2 outage. These were known by operations personnel, were properly marked and fire watches were properly posted.

7. Followup on Headquarters and Regional Requests (92701)

In response to a Regional request for information on the Independent Safety Engineering Group (ISEG) activities and functions at this site, the following information was submitted:

> There is no Technical Specification requirement for an ISEG at this site. NUREG-0117, Supplement No. 4, dated September 1980, Safety Evaluation Report Related to the Operation of Joseph M. Farley Nuclear Plant Unit 2 [Docket No. 50-364] addressed item I.B.1.2 of the TMI Action Items as a part of this site's licensee condition. This document accepted the licensee's organization [with their associated non-specified general activities] for closure of the item. The NUREG text (page 68) listed groups that would carry out ISEG-like functions. The NUREG listed groups were translated into procedures with specific functions that generally correspond to the TMI ISEG functions. These groups OET, and SAER.
>
> SP performs procedurally driven operational experience and equipment failure reviews as discussed in the NUREG. NRC issued documents are reviewed [by procedure] by the Technical Support group that is a different group from SP. The SP group communicates with the plant and SNC corporate staff on technical issues involving plant operation. The SP primary activities are plant testing and performance monitoring [ISI, LLRT, etc].
>
> OETs, which has ISEG-like engineering evaluation functions, were prevalent early in the 1980s and since that time have been reduced in frequency. The licensee has an understanding that the basis for these team evaluations stem from TS 6.2.3 under SAER functions. Since INPO evolved [after 1980] and plant operations stabilized, the frequency of these vertical slice or troubleshooting team evaluations have been reduced. There have been several corporate review groups that have looked at emergent problems such as the recent 1993 AFW pump suction problem, (IR 93-19). Several corporate committees were mentioned in the most recent SALP report. Team evaluations have been used recently on an approximate annual cycle and are described in SAER procedures.

SAER remained on site participating in on-site review committee functions. This group primarily audits plant functions under the QA program. The SAER manager on-site has a non-voting seat on the on-site review committee and actively reviews its functions. Although his position is non-voting he directly injected his and the SAER staff opinion into the committee's proceedings. He transmitted interactive observations and findings to the off-site review committee.

As a part of their regular activities, the above SP and SAER groups were routinely in the plant as functionaries. During this recent Unit 2 outage, the SAER staff had been frequently observed by the residents in the plant reviewing work performance and conducting programmatic audit functions. The SP and SAER groups appeared to be well respected by plant personnel.

The combined SP, OETs, and SAER groups did contribute positively to the safety of the plant. It was difficult to separate their normal functions from their ISEG-like functions since they were very similar. The personnel involved had diverse backgrounds and were generally "degreed" as discussed in the TMI action item I.B.1.2. However, unlike the TMI action item discussion/guidance, except for the SAER and the special teams, the personnel performing the ISEG-like duties were routinely involved with power plant production activities, but this should not be perceived as a negative comment.

The SALP board (IR 50-348,364/93-14) rated the engineering functional area, which includes Safety Assessment and Quality Verification, as category one. The off-site review committee and its arms were considered a strong driving force in good plant performance.

8. Action on Previous Inspection Findings (92700)

(Closed) Unit 2, URI 50-364/93-22-01, Incomplete scaffold permits.

Details of this unresolved item are described in paragraph 4.b. of this report. This item is now identified as an NCV 50-364/93-28-02, "Incomplete scaffold permits"; therefore the item is closed.

9. Exit Interview

Inspection scope and findings were summarized during management interviews throughout the report period and on November 24, with the plant manager and selected members of his staff. The inspection findings were discussed in detail and the licensee acknowledged the inspection findings. They did not identify as proprietary any material reviewed by the inspectors during this inspection. The licensee was informed that the item contained in paragraph 8 was closed.

ITEM NUMBER	DESCRIPTION AND REFERENCE
50-364/93-28-01 (NCV)	Inadequate shift supervisor review prior to release of work, paragraph 3.c
50-364/93-28-02 (NCV)	Incomplete scaffold permits, paragraph 4.c
50-364/93-28-03 (NCV)	Improperly installed RHR valve packing, paragraph 4.d
50-364/93-28-04 (URI)	Use of an out-of-date plant surveillance procedure for testing, paragraph 5.c
50-364/93-28-05 (IFI)	Fuel assembly mislocation - corrective actions, paragraph 3.b

10. Acronyms and Abbreviations

AFW - Auxiliary Feedwater
AP - Administrative Procedure
CCW - Component Cooling Water
CR - Control Room
CRAB - Containment Refueling Area Boundary
DP - Differential Pressure
DRP - Division of Reactor Projects, NRC
DRS - Division of Reactor Safety, NRC
DRSS - Division of Reactor Safeguards and Security
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EDSFI - Electrical Distribution System Functional Inspection
ESF - Engineered Safety Features
FHP - Fuel Handling Procedure
FNP - Farley Nuclear Plant
FP - Fire Protection
GMP - General Maintenance Procedure
HP - Health Physics
ISI - In-service Inspection
I&C - Instrumentation and Controls
INPO - Institute of Nuclear Power Operations
ISEG - Independent Safety Engineering Group
ISI - Inservice Inspection
IR - Inspection Report
LCO - Limiting Condition for Operation
LLRT - Local Leak Rate Testing
LOSP - Loss of Off Site Power
MCC - Motor Control Center
MDAFW - Motor Driven Auxiliary Feedwater [pump]
MOV - Motor-Operated Valve
MSIV - Main Steam Isolation Valve
MSR - Main Steam Reheater
MWR - Maintenance Work Request
NCV - Non-Cited Violation

NDE	-	Non-Destructive Examination
NIS	-	Nuclear Instrumentation System
NOV	-	Notice of Violation
OET	-	Operations Evaluation Team
OOS	-	Out Of Service
PCN	-	Plant Change Notice
PORC	-	Plant Operational Review Committee
PSA	-	Pacific Scientific Associates
QA	-	Quality Assurance
RCS	-	Reactor Coolant System
RE	-	Reactor Engineering
RHR	-	Residual Heat Removal
SAER	-	Safety Audit and Engineering Review
SFI	-	Shift Foreman Inspecting
SFO	-	Shift Foreman Operating
SFP	-	Spent Fuel Pool
S/G	-	Steam Generator
SI	-	Safety Injection
SNC	-	Southern Nuclear Operating Company
SNUG	-	Snubber Utility Group
SR	-	Surveillance Requirements
SO	-	Systems Operator
SP	-	System Performance
SS	-	Shift Supervisor
STAR	-	"Stop", "Think", "Act", "Review"
STP	-	Surveillance Test Procedure
SW	-	Service Water System
TCN	-	Temporary Change Notice
TMI	-	Three Mile Island
TS	-	Technical Specification
UOP	-	Unit Operating Procedure
URI	-	Unresolved Issue