UNITED STATES

NUCLEAR REGULATORY COMMISSION

REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

January 30, 2008

Southern Nuclear Operating Company, Inc.
ATTN: Mr. J. Randy Johnson
Vice President - Farley
Joseph M. Farley Nuclear Plant
7388 North State Highway 95
Columbia, AL 36319

SUBJECT: JOSEPH M. FARLEY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000348/2007005 AND 05000364/2007005

Dear Mr. Johnson:

On December 31, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Joseph M. Farley Nuclear Plant, Units 1 and 2. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 10, 2008, with yourself and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one NRC-identified and one self-revealing finding of very low safety significance (Green) both of which were determined to be violations of NRC requirements. Also, a licensee-identified violation, which was determined to be of very low safety significance, is listed in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy because of the very low safety significance of the violations and because they are entered into your corrective action program (CAP). If you contest any of these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at the Farley Nuclear Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Scott M. Shaeffer, Chief
Reactor Projects Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000348/2007005 and
05000364/2007005
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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Letter to J. Randy Johnson from Scott M. Shaeffer dated January 29, 2008

SUBJECT: JOSEPH M. FARLEY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000348/2007005 AND 05000364/2007005

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-348, 50-364, 72-42
License Nos.:	NPF-2, NPF-8
Report Nos.:	05000348/2007005 and 05000364/2007005
Licensee:	Southern Nuclear Operating Company, Inc.
Facility:	Joseph M. Farley Nuclear Plant
Location:	Columbia, AL 36319
Dates:	October 1 - December 31, 2007
Inspectors:	E. Crowe, Senior Resident Inspector S. Sandal, Resident Inspector R. Berryman, Senior Reactor Inspector (Sections 1R02 and 1R17) B. Caballero, Operations Engineer (Section 1R11) C. Even, Reactor Inspector (Sections 1R02 and 1R17) W. Fowler, Reactor Inspector (Sections 1R02 and 1R17) E. Michel, Reactor Inspector (Section 1R08) R. Moore, Senior Reactor Inspector (Section 4OA5)
Approved by:	Scott M. Shaeffer, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000348/2007005 and 05000364/2007005; 10/01/2007-12/31/2007; Joseph M. Farley Nuclear Plant, Units 1 & 2, Identification and Resolution of Problems and Event Followup.

The report covered a three-month period of inspection by the resident inspectors and reactor inspectors. Two Green non-cited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, Significance Determination Process (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, Reactor Oversight Process (ROP).

A. NRC-Identified and Self-Revealing Findings

- Green. The NRC inspectors identified a Green NCV for inadequate risk assessment which resulted in a Unit 2 reactor trip when performing switchyard relay testing. This event has been entered into the licensee's corrective action program (CAP) as Condition Report (CR) 2007109659.

  The inadequate risk assessment for the Unit 1 main generation differential lockout relay testing is a performance deficiency. The inspectors determined this finding was more than minor because it was associated with the procedure quality attribute of the Initiating Events cornerstone and adversely affected cornerstone objective in that loss of power to the 2A startup transformer resulted in a reactor trip. The inspectors determined that a Phase 2 risk analysis was required because the finding contributes to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. A regional Senior Reactor Analyst performed a Phase 3 risk analysis and concluded that the finding was of finding of very low safety significance (Green). This finding involved human performance cross-cutting aspect of complete, accurate and up-to-date design documentation, procedures, and work packages, and correct labeling of components. (Section 4OA2.2)

- Green. A Green self-revealing NCV was identified for gas binding of the 2A CCP that resulted in a failure to maintain the 'A' train of HHSI in an operable condition, in accordance with T.S. 3.5.2, ECCS. This event has been entered into the licensee's CAP as CR 2005112351.

  Performing an inadequate evaluation of external plant operating experience involving gas intrusion events resulting in inoperable HHSI pumps is a performance deficiency. This finding was more than minor because it affected the equipment performance attribute of the Mitigating Systems cornerstone and adversely impacted the cornerstone objective in that gas accumulation in the 2A HHSI pump suction piping rendered ECCS systems unavailable and unreliable. A Phase 3 risk analysis determined the finding was of very low safety significance (Green). This finding involved Problem Identification and Resolution (PI&R) cross-cutting aspects associated with the attribute of the licensee implementing available operating

experience through changes to plant processes, procedures, equipment and training to control pressure fluctuations in the volume control tank in order to prevent the formation of gas in HHSI pump suction piping. (Section 4OA3.2)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's CAP. This violation and its corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection report period in a scheduled refueling outage (RFO) which ended on November 13. The unit reached full rated thermal power (RTP) on November 18 and remained at this power level for the remainder of the inspection period.

Unit 2 began the inspection period at full RTP. On October 3, the unit tripped due to loss of power to the 2A Reactor Coolant Pump (RCP). The unit was restarted and reached full RTP on October 7. The unit remained at full RTP for the duration of the inspection report period.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R02 Evaluations of Changes, Tests or Experiments

a. Inspection Scope

The inspectors reviewed the six evaluations listed in the Attachment to confirm that the licensee had appropriately considered the conditions under which changes to the facility, Updated Final Safety Analysis Report (UFSAR), or procedures may be made and tests conducted without prior NRC approval. The inspectors reviewed additional information such as calculations, supporting analyses, the UFSAR, and drawings to confirm that the licensee had appropriately concluded that the changes could be accomplished without obtaining a license amendment. The inspectors also reviewed the 13 "screened out" changes listed in the Attachment for which the licensee had determined that evaluations were not required to confirm that the licensee's conclusions to "screen out" these changes were correct and consistent with 10CFR50.59. The inspectors also reviewed associated CRs to confirm that problems were identified at an appropriate threshold, were entered into the corrective action program, and appropriate corrective actions had been initiated.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walkdowns The inspectors performed partial walk-downs of the following four systems to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The walk-downs were performed using the criteria in licensee procedures FNP-0-AP-16, Conduct of Operations - Operations Group, and FNP-0-SOP-0, General Instructions to Operations Personnel. The walk-downs included reviewing the Updated Final Safety Analysis Report (UFSAR), plant procedures and drawings, checks of control room and plant valves, switches, components, electrical power line-ups, support equipment, and instrumentation. Documents reviewed are listed in the Attachment.

- Unit 1 ‘A’ and ‘B’ Train Residual Heat Removal (RHR) System during Mode 5 operations with Reactor Coolant System (RCS) drained down to 133'
- Unit 1 ‘A’ and ‘B’ Train Component Cooling Water (CCW) System during Mode 5 operations with RCS drained down to 133'
- Unit 1 ‘A’ Train Spent Fuel Pool (SFP) Cooling System during Mode 6 operations
- Unit 1 ‘A’ Train RHR System during Mode 5 operations with RCS drained down to 128' 6"

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

Fire Area Tours The inspectors conducted a tour of the six fire areas listed below to verify that combustibles and ignition sources were controlled in accordance with the licensee's administrative procedures; fire detection and suppression equipment was available for use; that passive fire barriers were maintained in good material condition, and that compensatory measures for out-of-service, degraded, or inoperable fire protection equipment were implemented in accordance with the requirements of licensee procedures FNP-0-AP-36, Fire Surveillance and Inspection; FNP-0-AP-38, Use of Open Flame; FNP-0-AP-39, Fire Patrols and Watches; and the associated Fire Zone Data sheets. Documents reviewed are listed in the Attachment.

- Unit 1 B Containment Spray (CS) pump room, Fire Zone 1
- Unit 1 B Charging Pump room, Fire Zone 5
- Unit 1 C Charging Pump room, Fire Zone 5
- Unit 1 Containment, Fire Zone 55
- Unit 2 A Direct Current (DC) Switchgear room, Fire Zone 18
- Unit 2 B DC Switchgear room, Fire Zone 19

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

Internal Flooding The inspectors reviewed selected risk-important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analysis and design documents, including the UFSAR, engineering calculations and abnormal operating procedures for licensee commitments. The inspectors walked-down the area listed below to verify plant design features and plant procedures for flood mitigation were consistent with the design requirements and internal flooding analysis assumptions. The inspectors reviewed flood protection barriers which included plant floor drains, condition of room penetrations, condition of the sumps in the rooms, and condition of water-tight doors. The inspectors also reviewed CRs to verify the licensee was identifying and resolving problems. Documents reviewed are listed in the Attachment.

- Unit 1 Piping Penetration Room 184

b. Findings

On November 1, the licensee performed boroscope inspections of the Unit 1 guard pipes associated with the encapsulated valves in the RHR and SC systems containment sump suction lines. The licensee initiated these inspections due to the continuing discovery of water in the encapsulations of these valves during quarterly inspections. When water was observed in the Unit 1 CS system Train B guard pipe, the licensee performed a core drill into the vertical pipe chase to which the was guard pipe attached and discovered approximately 500 gallons of water. The licensee decided to perform core drills of the remaining seven vertical pipe chases (3 on Unit 1 and 4 on Unit 2). The licensee discovered no water in the Unit 2 CS system Train A vertical pipe chase, but did discover approximately 100 gallons of water in the Unit 2 RHR system Train A vertical pipe chase. The licensee plans to assemble a team to review the chemical analysis of the water and the camera inspections of the vertical pipe chases to determine the source(s) of the water.

Water entering the vertical pipe chase could communicate with the containment sump suction isolation valve for each train of the RHR and CS systems and potentially render these valves inoperable. This issue will remain unresolved pending further review of the source of water and evaluation for adverse impact on system operability and is identified as Unresolved Item (URI) 05000348,364/2007005-01, Potential Flooding of Containment Sump Suction Valves.

1R08 Inservice Inspection (ISI) Activities

a. Inspection Scope

Piping Systems ISI. The inspectors reviewed the implementation of the licensee's ISI program for monitoring degradation of the RCS boundary and risk-significant piping system boundaries. The inspectors reviewed a sample from activities performed during the Unit 1, Fall 2007 refueling outage (RFO 21) including: nondestructive examination (NDE) required by the 1989 Edition (no Addenda) of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (B&PVC), Section XI; and welding activities associated with preemptive weld overlays of dissimilar metal welds on the pressurizer (PZR). The inspectors observed the conduct of, and reviewed NDE procedures, reports, equipment calibration and certification records, materials certification records, and personnel qualification records for the following NDE activities:

Ultrasonic examinations

- ALA2-4301-33-RI (6" carbon steel pipe-to-elbow Main Steam weld, Class 2)
- ALA-4301-34-RI (6" carbon steel elbow-to-pipe Main Steam weld, Class 2)
- ALA-4301-35-RI (6" carbon steel pipe-to-valve Main Steam weld, Class 2)

The inspectors reviewed the following examination record containing recordable indications and verified the indications were appropriately dispositioned in accordance with the ASME Code:

- ALA-4300-14-RI (32" carbon steel pipe-to-penetration Main Steam weld, Class 2)

The inspectors reviewed the following repair/replacement activity for compliance with ASME Code:

- Weld overlays performed in accordance with commitments of the Confirmatory Action Letter issued March 29, 2007, covering corrective actions taken to address safety concerns associated with primary water stress corrosion cracking of dissimilar metal nozzle welds at PZR surge lines. This included weld overlays completed on PZR safety valve nozzles, and the surge nozzle.

The inspectors reviewed weld process control sheets, welder operating instructions, welding procedure specifications, welding procedure qualification records, welder qualification records, Certified Material Test Reports for weld material, and non-destructive examination reports.

The inspectors reviewed the licensee's completion of pressure testing for buried piping done in accordance with the ASME B&PVC, Section XI IWA-5244, or an approved relief request as per 10CFR50.55a(g)(5)(iv), for the second and third intervals.

The inspectors reviewed the licensee's procedures, documentation, and corrective actions associated with the temporary non-code repair of a Unit 1, "B" train, SW strainer bypass piping pin-hole leak conducted in accordance with Generic Letter (GL) 90-05.

The inspector reviewed the licensee's initial corrective actions regarding suspected reactor coolant leakage from PZR heater sleeve penetrations 1 and 2.

Reactor Vessel Upper Head (RVUH) The Unit 1 RVUH was replaced in the fall of 2004, and was in the "Replaced" category as defined in EA-09-003. The licensee was not required to perform either bare metal visual or volumetric exams during the current refueling outage, thus no sample was available for this portion of the ISI inspection procedure. The inspectors reviewed the licensee's calculation of Effective Degradation Years as required by EA-03-009. The inspectors also verified completion of leakage checks required by EA-03-009,IV,D.

Boric Acid Corrosion Control (BACC) Program The inspectors reviewed the licensee's BACC program activities to ensure implementation with commitments made in response to NRC GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary," and applicable industry guidance documents. Specifically, the inspectors performed an on-site record review of procedures and plant issue reports documenting the results of containment walkdown inspections. The inspectors also reviewed the walkdown of containment by the resident inspectors to evaluate compliance with licensee's BACC program requirements and verify degraded or non-conforming conditions, such as boric acid leaks, were properly identified and corrected in accordance with the licensee's CAP.

The inspectors reviewed the two following engineering evaluations completed for evidence of boric acid found on systems containing borated water to verify the minimum design code required section thickness had been maintained for the affected components.

- N-2004-2728, Boric acid found on piping between valves on safety injection system
- N-2005-5034, Boric acid on "A" low head safety injection (LHSI) suction line.

Steam Generators (SGs) ISI No eddy current examinations of SG tubing were performed during the RFO. The inspectors evaluated the licensee's documented review of the previous outage degradation and operational assessments. This review revealed that 91 foreign objects remained in the Unit 1 SGs following 1RFO20. The inspectors reviewed the licensee's evaluations for selected foreign objects remaining in the SGs, and reviewed the licensee's CAP plans related to foreign object introduction in the SGs.

Identification and Resolution of Problems The inspectors performed a review of ISI-related problems, including SG maintenance and the BACC program, that were identified by the licensee and entered into the CAP. The inspectors reviewed the associated CRs to confirm that the licensee had appropriately described the scope of the problem and had initiated corrective actions. The review also included the licensee's consideration and assessment of operating experience events applicable to the plant. The inspectors performed this review to ensure compliance with 10CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

Resident Inspector Quarterly Review On November 20, the inspectors observed the performance of the five following in-plant Job Performance Measures (JPMs) administered to plant operators to verify implementation of procedures FNP-0-AP-45, Farley Nuclear Plant Training Program; and FNP-0-TCP-17.3, Licensed Retraining Program Administration (Classroom). The inspectors verified that the JPMs were developed using current station procedures and policies. The inspectors observed operator actions, overall task performance, self-critiques, training feedback, and management oversight to verify that operator performance was evaluated against the performance standards of the licensee's JPMs.

- SO-058A, Breaking Vacuum on the Main Condenser
- SO-269B, Establishing Alternate Cooling to Charging Pump
- SO-351A, Shedding Non-Essential DC Loads
- SO-605, Locally Starting Emergency Diesel Generator (EDG)
- SO-607B, Establishing Emergency Power to MOV-8803B

Annual Review of Licensee Requalification Examination Results On September 7, 2007, the licensee completed the requalification annual operating tests, required to be given to all licensed operators by 10 CFR 55.59(a)(2). The inspectors performed an in-office review of the overall pass/fail results of the individual operating tests and the crew simulator operating tests. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance SDP.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the two samples listed below for items such as: (1) appropriate work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b); (4) characterizing reliability issues for performance; (5) trending key parameters for condition monitoring; (6) charging unavailability for performance; (7) classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); and (8) appropriateness of performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/functions classified as (a)(1). In addition, the inspectors specifically reviewed events where ineffective equipment maintenance has resulted in invalid automatic actuations of Engineered Safeguards Systems affecting the operating units. Documents reviewed are listed in the Attachment.

- Unit 2 Instrument Air Dryers
- Unit 1 B1F Sequencer

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the following seven activities to verify appropriate risk assessments were performed prior to removing equipment for work. The inspectors verified risk assessments were performed as required by 10 CFR 50.65(a)(4), and were accurate and complete. When emergent work was performed, the inspectors verified the appropriate use of the licensee's risk assessment and risk categories in accordance with the requirements in licensee procedures FNP-0-ACP-52.3, Mode 1, 2, & 3 Risk Assessment; NMP-GM-006, Work Management; and FNP-0-AP-16, Conduct of Operations - Operations Group.

- Unit 2, October 1 - Yellow emergent risk condition identified prior to start of maintenance concurrent with surveillance testing of 1C DG
- Unit 1, October 1 - Orange risk condition due to SG not available for heat removal during RFO
- Unit 1, November 4 - Orange risk condition due to draining the reactor coolant system (RCS) to mid-loop in preparation for RCS vacuum refill
- Unit 1, November 13 - Yellow risk condition due to auxiliary feedwater (AFW) pump surveillance testing concurrent with high voltage switchyard maintenance
- Unit 2, November 17 - Yellow risk condition due to 2B motor driven auxiliary feedwater (MDAFW) pump quarterly surveillance testing
- Unit 2, November 21 - Green risk condition due to 2C Charging Pump discharge check valve declared inoperable following quarterly surveillance testing
- Unit 2, December 10 - Green risk condition due to 2B DG scheduled surveillance concurrent with 2C charging pump and anticipated transient without scram; mitigating system actuation circuitry surveillance testing

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following five operability evaluations to verify they met the requirements of licensee procedures FNP-0-AP-16, Conduct of Operations - Operations Group and FNP-0-ACP-9.2, Operability Determination, for technical adequacy, consideration of degraded conditions, and identification of compensatory measures. The inspectors reviewed the evaluations against the design bases, as stated in the UFSAR and Functional System Descriptions to verify system operability was not affected.

- CR 2007109523, Unit 2, RWST boron concentration below administrative limits
- CR 2007109419, Unit 1, poly sheet left unattended in containment over transfer canal
- CR 2007110314, Unit 2, water drained from 2B EDG rocker arm lube oil reservoir
- CR 2007110411, Unit 1, ‘B’ RHR pump did not start when demanded
- CR 2007112145, Unit 1, water drained from 1-2A EDG rocker arm lube oil reservoir

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

Permanent Plant Modifications The inspectors reviewed the following plant modification to verify the implementation of procedure FNP-0-AP-8, Design Modification Control. This included verification that the design basis, licensing basis, and performance capability of risk significant systems, structures, and components would not be degraded through the modification and the modifications would not place the plant in an unsafe condition. The inspectors also discussed the modifications with engineering and operations personnel, and reviewed the related procedures and drawings. Documents reviewed are listed in the Attachment.

- Document Control Procedure (DCP) 2070508101, Unit 2 motor operated valve (MOV) 8811A/8811B modification

Biennial Review The inspectors evaluated engineering change packages for the following six modifications to evaluate the modifications for adverse effects on system availability, reliability, and functional capability. Documents reviewed included procedures, engineering calculations, modification design and implementation packages, work orders, site drawings, corrective action documents, applicable sections of the living UFSAR, supporting analyses, TSs, and design basis information. The inspectors additionally reviewed test documentation to ensure adequacy in scope and conclusion.

- DCP C063531801, "Diesel Generator Heat Exchanger Material Change Rev. 1", 5/12/07 (Mitigating Systems)
  Materials/Replacement components, Heat Removal, Flowpaths, Structural, Process Medium

- DCP 1053131101, "Replacement of 1B MDAFW Pump Motor", 5/1/06 (Mitigating Systems)

Materials/Replacement Components, Energy Needs, Equipment Protection, Licensing Basis

- MDC-1062216401, Transformer Tap Setting Change, Rev. 1 (Mitigating Systems)
  Energy Needs, Failure Modes, Licensing Basis

- MDC-2061472301, Service Water Cyclone Separator Motor Replacement, Rev. 1 (Mitigating Systems)
  Energy Needs, Materials/Replacement Components, Equipment Protection, Licensing Basis

- MDC-S051298201, 2C DC Annunciator Replacement, Rev. 1 (Mitigating Systems)
  Energy Needs, Timing, Licensing Basis

- DCP-2029983301, TDAFW UPS Replacement, Rev. 1 (Mitigating Systems)
  Energy Needs, Materials/Replacement Components, Timing, Licensing Basis

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the criteria contained in licensee procedures FNP-0-PMT-0.0, Post-Maintenance Test Program, to verify post-maintenance test procedures and test activities for the following nine systems/components were adequate to verify system operability and functional capability. The inspectors also witnessed the test or reviewed the test data to verify that test results adequately demonstrated restoration of the affected safety function(s). Documents reviewed are listed in the Attachment.

- FNP-1-STP-45.5, RHR Cold Shutdown Valves Inservice Test following maintenance on valve from 1C RCS loop to 1A RHR pump (Q1E11V016A)
- FNP-1-STP-24.16, Containment Cooler and RCP Motor Air Cooler Service Water Valves Inservice Test following maintenance on Service Water valve from RCP motor air coolers (Q1P16V072)
- FNP-1-STP-40.0, ‘A’ Train Safety Injection with Loss of Off-Site Power (LOSP) Test following ‘A’ train electrical bus and breaker maintenance
- FNP-1-STP-40.0, ‘B’ Train Safety Injection with LOSP Test following ‘B’ train electrical bus and breaker maintenance
- FNP-1-STP-73.6, Verification of Reactor Head Vent Valve Operation from the Hot Shutdown Panel following maintenance on reactor vessel head vent outer isolation valves (Q1B13SV2213A and Q1B13SV2213B)
- FNP-1-STP-627, Local Leak Rate Testing of Containment Penetrations following maintenance on nitrogen supply check valve to accumulators (Q1E21V058)

- FNP-1-STP-33.0B, Solid State Protection System (SSPS) Train B Operability Test following maintenance on SSPS universal logic cards
- FNP-1-STP-22.16, Turbine Driven Auxiliary Feedwater Pump (TDAFW) Quarterly Inservice Test (Tavg > 547°F) following weld crack of mini-flow line drain valve weld
- FNP-0-SOP-38.0, EDGs following repairs to the starting air system 'A' compressor for the 1-2A DG

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

a. Inspection Scope

Refueling Activities The inspectors reviewed the following activities related to the Unit 1 RFO for conformance to licensee procedure FNP-0-UOP-4.0, General Outage Operations Guideline, and FNP-1-UOP-4.1, Controlling Procedure for Refueling. Surveillance tests were reviewed to verify results were within the TS required specification. Shutdown risk, management oversight, procedural compliance, and operator awareness were evaluated for each of the following activities. In response to operational experience concerns regarding reactor vessel head lifts (NRC Operating Experience Smart Sample FY2007-03), the inspectors reviewed licensee programs and procedures to determine if current practices were within the current licensing basis. The inspectors reviewed the documents listed in the Attachment of this report related to heavy load lifts of the reactor vessel head and conducted discussions with licensee personnel. Documents reviewed are listed in the Attachment.

- Outage Risk Assessment
- Cooldown
- Core offload and reload
- Reactor coolant instrumentation
- Electrical system alignments and bus outages
- Reactor vessel disassembly and assembly activities
- Outage-related surveillance tests
- Containment Closure
- Low Power Physics Testing and Startup Activities
- Clearance Activities
- Decay Heat Removal and SFP Cooling
- Containment heavy load lifts

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed surveillance test procedures and either witnessed the test or reviewed test records for the following surveillance tests to determine if the tests adequately demonstrated equipment operability and met the TS requirements. The inspectors reviewed the activities to assess for preconditioning of equipment, procedure adherence, and valve alignment following completion of the surveillance. The inspectors reviewed licensee procedures FNP-0-AP-24, Test Control; FNP-0-M-050, Master List of Surveillance Requirements; and FNP-0-AP-16, Conduct of Operations - Operations Group; and attended selected briefings to determine if procedure requirements were met. Documents reviewed are listed in the Attachment.

Surveillance Tests
- FNP-1-ETP-4472, Containment Purge Exhaust Filtration Performance Test
- FNP-1-STP-22.16, TDAFW Pump Quarterly Inservice Test (Tavg > 547°F) performed on November 10, 2007

In-Service Test
- FNP-2-STP-22.1, 2A AFW Pump Quarterly Inservice Test

Containment Isolation Valves
- FNP-1-STP-627, Local Leak Rate Testing of Containment Penetrations, Penetration 32

RCS Leak Detection
- FNP-2-STP-9.0, RCS Leakage Test

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following two temporary modifications (TM) and associated 10CFR50.59 screening criteria against the system design bases information and documentation and the licensee's TM procedure FNP-0-AP-8, Design Modification Control. The inspectors reviewed implementation, configuration control, post-installation test activities, drawing and procedure updates, and operator awareness for this TM. Documents reviewed are listed in the Attachment.

- TM 2071001901, Unit 1 Q2P16MOV3134 close torque switch bypass modification
- TM 2071012801, Unit 2 C RCP #3 seal leak-off line elevation

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Prepardenesses

1EP6 Drill Evaluation

a. Inspection Scope

The resident inspectors evaluated the following routine licensee emergency drill to identify any weaknesses and deficiencies in classification, notification, and protection action recommendation (PAR) development activities. The inspectors observed emergency response operation in the simulated control room to verify that event classification and notifications were done in accordance with FNP-0-EIP-9.0, Emergency Classification and Actions. The inspectors used procedure FNP-0-EIP-15.0, Emergency Drills, as the inspection criteria. The inspectors also reviewed the licensee critique of the drill to compare any inspector-observed weaknesses with those identified by the licensee in order to verify whether the licensee was properly identifying failures.

- December 5, Small break loss of coolant accident (SBLOCA) with fuel failure; manual safety injection due to increased leak rate with unavailability of ‘B’ train of CCW, ‘B’ train charging pump, ‘B’ train RHR pump, failure of containment fan coolers, and failure of the 1A containment spray pump; large break loss of coolant accident (LBLOCA) with breach of containment and subsequent PAR upgrade required

b. Findings

No findings of significance were identified.

4 OTHER ACTIVITIES (OA)

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee data for the PIs listed below to verify the accuracy of the PI data reported during the period listed. Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Rev. 5, was used to verify the basis in reporting for each data element. Documents reviewed are listed in the Attachment.

Mitigating Systems Cornerstone
- Mitigating System Performance Index, High Pressure Injection Systems
- Mitigating System Performance Index, RHR Systems

The inspectors reviewed samples of raw PI data, Licensee Event Reports (LERs), and Monthly Operating Reports for the period covering January 1, 2007 through December

31, 2007. The data reviewed from the LERs and Monthly Operating Reports was compared to graphical representations from the most recent PI report. The inspectors also examined a sampling of operations logs and procedures to verify the PI data was appropriately captured for inclusion into the PI report as well as ensuring that the individual PIs were calculated correctly.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Daily Review

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished by reviewing daily hard copy summaries of CRs and by reviewing the licensee's electronic CR database.

.2 Selected Issue Follow-up Inspection

a. Inspection Scope

In addition to the routine review, the inspectors selected the four issues listed below for a more in-depth review. The inspectors considered the following during the review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of CRs; and (7) completion of corrective actions in a timely manner.

- CR 2007109644, Unit 1, White residue observed on PZR heater sleeve penetrations #1 and #2
- CR 2007109659, Unit 2, Reactor Trip on October 3, 2007 during planned maintenance in the High Voltage Switchyard (HVSWYD)
- CR 2007110411, Unit 1, RHR pump 1B failure to start when demanded from the Main Control Board (MCB)
- CR 2007111522, Unit 1, TDAFW pump miniflow drain line weld crack

b. Observations and Findings

CR 2007109644 The inspectors reviewed the licensee's onsite and vendor chemical analysis of the samples, condition report documenting the discovery of the suspect material and licensee's efforts to discover the source of the suspect material. The inspectors determined the licensee promptly identified the condition, the licensee's efforts to discover the source of the suspect material were timely and multiple possible sources of leakage including previous work activities were evaluated. The inspectors noted the licensee discovered no active reactor coolant system leakage during their search for a credible source. Therefore, the inspectors determined this was not reportable per NRC requirements.

CR 2007110411 The inspectors determined the licensee continued to promptly identify problems in a timely manner even though the licensee continued to be challenged with consideration of extent of condition, generic implications, common cause, and previous occurrences. The inspectors also noted the licensee continued to be challenged to identify the root and contributing causes of the above issues in their early efforts. However, the inspectors noted the licensee sought the assistance of an independent assessment team. The NRC AIT provided oversight to this independent assessment team. The AIT conducted further review of the above issues which were addressed as unresolved items in Inspection Report 05000348/364/2007010.

CR 2007111522 The inspectors noted the licensee determined the root cause of the above events as high vibration levels on much of the AFW piping being the primary contributor. The inspectors agreed with the licensee's evaluation of extent of condition but felt the licensee's corrective actions had been less than timely. The licensee's corrective actions includes gathering vibration data which has been occurring over the past five years. The licensee completed this evaluation in 2006 and determined that cavitation is occurring downstream of these mini-flow line orifices. The licensee plans to replace the orifices with "dirty trim valves" which will serve to reduce system pressure in stages and thus prevent cavitation. These modifications are planned on both units during their up-coming RFO. The inspectors noted these cracks were occurring in non-safety related piping and that licensee data indicates the ability of the Auxiliary Feedwater System to deliver flow to the steam generators during accident conditions would not be adversely affected.

CR 2007109659

Introduction. The NRC inspectors identified a Green NCV for inadequate risk assessment which resulted in a Unit 2 reactor trip when performing switchyard relay testing.

Description. On October 1, the licensee removed the #2 Auto Transformer in the high voltage switchyard (HVSWYD) from service for maintenance. The alignment in the HVSWYD resulted in the Unit 2 ‘B’ Startup Transformer being powered through only one of two normal power supplies. On October 3, licensee personnel performed testing of the Unit 1 main generator differential lockout relay per station procedure FNP-1-EMP-2541.01, N1N31RLYGEN1HEA Main Generator Differential Lockout Relay Function Test. As part of this test, the licensee defeated opening of the main generator output breakers upon receipt of the differential lockout relay test signal. When the test signal was inserted, selective tripping sequence logic downstream of the main generator output breakers resulted in the loss of one of two 230kV HVSWYD buses and the loss one of four offsite power supplies. Both Unit 1 startup transformers and startup transformer 2A lost one of their normal power supplies. Startup transformer 2B, which had previously lost one normal power supply due to the #2 Auto Transformer maintenance, lost its second power supply which resulted in the de-energization of the startup transformer. Startup transformer 2B supplied power to the 'A' RCP bus and the 4160-volt safety related bus 'G' both of which lost power. Loss of power to the 'A' RCP resulted in an automatic reactor trip of Unit 2. Loss of power to bus 'G' resulted in an automatic start of 2B EDG which re-energized the 'G' safety-related bus.

The licensee used three risk assessments to evaluate the overall plant risk. One assessment was a daily 'look ahead' of maintance scheduled for the week. The second assessment was conducted using procedure FNP-0-ACP-4.0, Switchyard Control. The third assessment was the shift supervisors' review of daily work activities. There were multiple failures of these risk assessment processes which resulted in loss of power to the 2B startup transformer.

- The licensee assessed the Unit 1 risk as ORANGE and established a risk management action of not peforming work that would result in HVSWYD breakers 904 and 924 opening. The licensee did not understand that, because main generator breaker opening was defeated the during the MGDLOR test, HVSWYD protective sequential relaying would cause both breakers 904 and 924 to open. Therefore, the licensee failed to identify that the MGDLOR test should not have been performed.
- The licensee did not intergrate the MGDLOR test with the #2 Autotransformer work in the daily 'look ahead' for Unit 2.
- The licensee believed incorrectly the MGDLOR would be isolated during the test and assessed the risk as low using procedure FNP-0-ACP-4.0, Switchyard Control. This incorrect information was included in the MGDLOR test pre-job briefing.
- The licensee used a different risk assessment process which did not consider the #2 Autotransformer work in the daily 'look ahead' for Unit 1.
- Shift supervisors relied on the MGDLOR test pre-job briefing in their risk evaluation.
- Shift supervisors failed to consider the risk of the 2B startup transformer being supplied by only one power source.

<u>Analysis</u>. The inadequate risk assessment for the Unit 1 main generation differential lockout relay testing is a performance deficiency. The inspectors determined this finding was more than minor because it was associated with the procedure quality attribute of the Initiating Events cornerstone and adversely affected cornerstone objective in that loss of power to the 2A startup transformer resulted in a reactor trip. The inspectors determined that a Phase 2 risk analysis was required because the finding contributes to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. A regional Senior Reactor Analyst performed a Phase 3 risk analysis and concluded that the finding was of finding of very low safety significance (Green). The key assumptions used in the analysis were:

- The event was modeled with basic events IE-TRANS (Transient) and ACP-TFM-FC-SUT1B (230 to 4.2 Startup Transformer) set to 1.0. This meant the startup transformer always initially failed with an initiating event frequency of 1.0.

- There was a 50/50 chance that either support system train would be on-service. Therefore, the risk results were partitioned accordingly.

- Recovery credit was assigned based upon SPAR-H methodology with the performance shaping factors altered for high stress, highly complex, and poor procedures.

- The risk increase due to another initiator occurring during the two hour time interval that the Startup Transformer was out of service was not quantified due to its very small risk contribution.

The NRC's Probabilistic Risk Assessment model was used for the risk analysis with the addition of logic to credit rapid depressurization and cool down upon the loss of all HHSI/Charging with a RCP Seal Loss of Coolant Accident in progress. This set the logic consistent with the SDP Notebook and the licensee's full scope model. The dominant sequence was:

- Failure of the Startup Transformer * EDG B Failure * The off-service CCW Train in Test & Maintenance * ensuing RCP Seal LOCA * Failure to align the backup Train of CCW to the A Train power source failing the A Train of Low Pressure Recirculation

The inspectors determined the issue had Human Performance cross-cutting aspect of complete, accurate and up-to-date design documentation, procedures, and work packages, and correct labeling of components. (H.2(c))

Enforcement. 10CFR50.65(a)(4) states, in part, that prior to maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to the above, on October 3, the licensee performed surveillance testing of the Unit 1 main generator differential lockout relay without performing an adequate risk assessment of the effects of this testing. Because of the very low safety significance and because the licensee entered this event in the CAP as CR 2007109659, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000348, 364/2007005-02, Failure to Adequately Assess Risk Resulting in Unit 2 Reactor Trip.

.3 Semi-Annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, the inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors review focused on repetitive equipment and corrective maintenance issues but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.1. The review also included issues documented outside the normal CAP in system health reports, corrective maintenance Work Orders (WOs), component status reports, and MR assessments. The inspectors' review nominally considered the six-month period of July through December 2007, although some examples expanded beyond those dates when the scope of the trend warranted. The inspectors compared and contrasted their results with the results contained in the licensee's latest integrated quarterly assessment report. Corrective actions associated with a sample of the issues identified in the licensee's trend report were reviewed for adequacy. Specific documents reviewed are listed in the Attachment.

b. Assessment and Observations

The inspectors noted the following trends:

- Procedure usage/adherence The inspectors noticed a continuing negative trend in the area of procedure use and adherence. The inspectors noted the individual issues were generally spread across the general site population with the more significant issues related to the Operations Department. The licensee had generated CRs for each of the issues occurring during the third and fourth quarters of 2007. The licensee previously identified this negative trend in the third quarter of 2006 as an emerging trend.

- Safety Related 4160 Circuit Breakers The inspectors noticed the continuance of a negative trend in the area of 4160 circuit breaker failures. Most recently, the licensee experienced circuit breaker failures of the 1A and 1C CCW pumps and the 1B RHR pump. The licensee also experienced work-in-progress issues with three additional circuit breakers on the “F” safety related 4160 volt bus during circuit breaker replacement during the recent Unit 1 RFO. The licensee first identified the adverse trend in April, 2006. The licensee generated a long range plan to replace the aging Allis-Chalmers breakers with Cutler-Hammer breakers which is still on-going. The rate of replacement was increased following failures during the fourth quarter of 2006. The licensee has replaced the breakers in the "H" and "J" buses which supply the non-safety related River Water Pumps and the "K" and "L" buses which supply the safety related SW Pumps. The licensee has also replaced breakers in both Unit 1 safety related buses “F” and “G”. The licensee was replacing the remainder of the safety related breakers at the next opportunity with a planned completion date in early 2008.

4OA3 Event Followup

.1 (Closed) LER 05000364/2007-001-00, Unit 2 Reactor Trip during Unit 1 Main Generator Differential Lockout Relay Testing

On October 3, a Unit 2 reactor trip occurred due to loss of power to the 2B Startup Transformer. The inspectors discussed the event with operations, engineering, and licensee management personnel. The inspectors reviewed operator actions taken in accordance with licensee procedures and reviewed unit and system indications to verify that actions and system responses were as expected. This event is further discussed in Section 4OA2.2 of this report.

.2 <u>(Closed) LER 05000364/2005-001-00, Gas Binding of the Unit 2 A Train High Head Safety Injection (HHSI) Pump</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the LER and associated CR 2005112351. This review verified the causes for the December 4, 2005, event involving gas binding of the Unit 2 ‘A’ HHSI pump, were identified and that corrective actions were reasonable. Excessive variations in volume control tank pressure over a short period of time subsequently allowed gas bubble formation and migration to the idle pump suction line. The gas bubble formation was of sufficient volume to render the ‘A’ train of HHSI inoperable during modes of plant operation when the train was required to be operable. The inspectors reviewed plant parameters and gas accumulation quantities, as well as verified that notifications were made in accordance with 10 CFR 50.72. Documents reviewed during this inspection are listed in the Attachment.

b. <u>Findings</u>

<u>Introduction</u>. A Green self-revealing NCV was identified for gas binding of the 2A CCP that resulted in a failure to maintain the ‘A’ train of HHSI in an operable condition, in accordance with TS 3.5.2, ECCS.

<u>Description</u>. The licensee’s root cause investigation determined the cause of the gas accumulation was excessive variations in volume control tank pressure. The volume control tank pressure fluctuations led to the formation of a gas bubble in the suction line of the Unit 2 ‘A’ HHSI pump. Inoperability of the pump was discovered on December 4, 2005, when the pump was started and the licensee observed it failed to develop normal discharge pressure or charging flow. The pump was immediately stopped. The licensee later determined that the gas accumulation in the ‘A’ HHSI train suction piping resulted in the pump becoming gas bound.

The inspectors determined the licensee had prior opportunities to evaluate industry events to identify and evaluate pressure fluctuations in the volume control tank as a potential HHSI system gas source and to evaluate plant operations leading to subsequent inoperability of ECCS equipment.

<u>Analysis</u>. Performing an inadequate evaluation of external plant operating experience involving gas intrusion events resulting in inoperable HHSI pumps was a performance deficiency. This finding was more than minor because it affected the equipment performance attribute of the Mitigating Systems cornerstone and adversely impacted the cornerstone objective in that gas accumulation in the 2A HHSI pump suction piping rendered ECCS systems unavailable and unreliable. The inspectors determined a Phase 2 risk analysis was required because of the a loss of a single train for greater than its TS allowed outage time. The finding was evaluated using the following assumptions: (1) the 2A charging pump was not available for those events requiring “A” train HHSI flow; and (2) the finding existed for a duration of between three and 30 days. The evaluation determined a Phase 3 evaluation was required by the senior reactor

analyst. The Phase 3 analysis concluded the deficiency was characterized as a finding of very low safety significance (Green). The key assumptions used in the analysis were:

- The header for the 2A HHSI pump was vertically higher than the other two pumps. Gas intrusion into this lower elevation would have affected the on-train operating pump significantly, reducing the exposure time. Consequently, common cause was not included in the non-conforming case.

- No operator recovery was considered.

- For ease of analysis, the exposure time selected was based upon the most risk significant configuration – B as the on-service train. The risk quantification used 108 hours for the exposure period.

The NRC's Probabilistic Risk Assessment computer model was used. The addition of logic to credit rapid depressurization and cool down upon the loss of all HHSI/Charging with a RCP Seal LOCA in progress was included. This made the logic consistent with the NRC's SDP Notebook and the licensee's full scope model. The dominant accident sequences were:

- A Loss of 4160 VAC G Bus with the performance deficiency created a transient and a loss of cooling to the RCP Seals. A Seal LOCA ensued with rapid depressurization and cool down of the RCS. However, the Low Pressure Recirculation function failed via various mechanisms.

- A Loss of the On-Train SW "B" Train coupled with the performance deficiency created another way to lose cooling to the RCP Seals and a transient on the unit. A RCP Seal LOCA ensued with rapid depressurization and cool down of the RCS. However, the Low Pressure Recirculation function fails via various mechanisms.

This finding was identified to have a cross-cutting aspect in the area of problem identification and resolution (PI&R) because the licensee did not implement available operating experience through changes to plant processes, procedures, equipment and training to control pressure fluctuations in the volume control tank in order to prevent the formation of gas in HHSI pump suction piping (P.2(b)).

Enforcement. T.S. 3.5.2, ECCS, requires that both trains of ECCS be operable in Modes 1, 2, and 3 and at least 100 percent of the ECCS flow equivalent to a single operable ECCS train be available. Contrary to the above, the Unit 2 'A' HHSI pump and associated train was made inoperable on November 25, 2005 for a period of 212 hours and 44 minutes. During this time period, the 2A HHSI pump and its associated train were required to be operable for a period of 93 hours and 1 minute. Two ECCS trains were not maintained in an operable condition within the allowed TS restoration time of 72 hours. Because this failure to maintain two ECCS trains operable was of very low safety significance (Green) and has been entered into the CAP as CR 2005112351, this violation is being treated as an NCV, consistent with Section VI.A of the NRC

Enforcement Policy: NCV 05000364/2007005-03, “Failure to Maintain Two ECCS Trains Operable Due to Gas Accumulation In the Charging Pump Suction Piping.”

.3 (Closed) LER 05000348/2007-001-00, Technical Specification 3.8.1 Violation Due to Failure of Breaker/Mechanism-Operated Cell (MOC) Switch

On April 26, 2007, the licensee performed an operability test of the 1C EDG and determined the mechanism-operated cell (MOC) switch was not fully activated when the breaker was closed. The licensee declared the EDG inoperable. An inspection determined that the MOC switch rotation was not sufficient to fully engage the normally open contacts. The event was the result of a fit-up discrepancy during replacement of the existing Allis Chalmers breakers with the new Cutler-Hammer breakers with the Allis Chalmers switchgear. The new Cutler-Hammer breaker was installed in the switchgear November 1, 2006. From the period of time from November 1, 2006 through April 26, 2007, the 1B EDG was unavailable for operation due to maintenance activities on five occasions. During the period the 1B EDG was inoperable, a dual unit loss of offsite power with a concurrent safety injection on Unit 2 would have resulted in the complete loss of function provided by these emergency diesel generators. In the event this scenario occurred, operator action would have been required to energize the 1F 4160 safety related electrical bus and start the required safety related loads after the 1C EDG automatically connected to the 1H 4160 electrical bus. The licensee’s probability risk assessment model conservatively assumes that the 1C EDG will be started and loaded by the operator rather that crediting automatic start. Therefore, this does not represent an increase in risk in the licensee’s probability risk assessment model.

On May 3, 2007, the NRC conducted a supplemental inspection per Inspection Procedure 95001. The inspectors reviewed CR 2007104092 including the root cause investigation and licensee corrective actions. NRC inspection report 2007008 documented a violation of NRC 10 CRF 50, Appendix B, Criterion XVI citing two examples of which the above MOC switch issue was one. The resident inspectors reviewed the LER submittal and determined that no additional findings of significance were identified.

.4 (Closed) LER 05000348/2006-002-00, Main Steam Isolation Valve Failure to Close

On April 8,2006, with Unit 1 in Mode 3 prior to cooldown for a refueling outage, during Main Steam Isolation Valve (MSIV) and Bypass Valves Cold Shutdown Valves Inservice Test, the Unit 1 downstream MSIV's failed to fully stroke closed. The ‘A’ MSIV valve closed approximately 70%, and MSIV’s ‘B’ and ‘C’ did not move from the full-open position. On April 9, 2006, following completion of cooldown, all three valves would stroke both open and closed from the Main Control Room. The licensee determined this event was caused by inadequate preventive maintenance on shaft load bearing components, improper valve assembly, omission of relevant information in the procedure and turbulence in the downstream valves resulting in a more severe duty condition than in the upstream valves. This event is further discussed in NRC Special Inspection Report 05000348/2006009 and NRC Intergrated Inspection Report 05000348,364/2006005. The inspectors reviewed the LER and and CR 2006103043 including the root cause and corrective actions. No additional findings of significance were identified.

4OA5 Other Activities

.1 (Open) Temporary Instruction (TI) 2515/166, Pressurized Water Reactor Containment Sump Blockage (NRC GL 2004-02) - Unit 1

a. Inspection Scope

The inspector verified the implementation of the licensee's commitments documented in their August 31, 2005, response (NL-05-1264) to GL 2004-02, Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors. The commitments, referenced as corrective actions in the response, included plant modifications and procedure changes. The modifications included removal of RHR and containment spray (CS) pumps' suction line vortex breakers, replacement of HHSI system throttle valves and orifices, removal of reactor cavity drain covers and installation of orifices in the reactor cavity drain lines. Program controls were to assure the assumptions regarding post LOCA debris generation and transport remain valid. Additionally a license basis change to include in the FSAR a description of the new mechanistic evaluation methodology was listed as an action.

This inspection included review of the sump screen assembly installation work documentation, screen assembly modification 10 CFR 50.59 evaluation, structural (debris) loading calculation, and validation testing of the modified sump screen design. Additionally the inspector reviewed the implementation and 10 CFR 50.59 evaluations for all modifications related to GL 2004-02 for Unit 1. The net positive suction head (NPSH) calculation for the RHR and CS pumps was reviewed for the new screen configuration. The inspector also reviewed the foreign materials exclusion controls and the completed Quality Assurance / Quality Control records for the screen assembly installation. The inspectors conducted a visual walkdown to verify the screen assembly configuration being installed was consistent with drawings and the tested configuration. The sump screen modification was not completed during the inspection. The resident inspectors verified the completion of the containment sump screen installation at the end of the outage.

b. Findings and Observations

No findings of significance were identified. The licensee's actions for Unit 1, stated in their August 31, 2005, response to GL 2004-02, were not complete during this inspection. The following is a listing of the corrective action commitments listed in the licensee's GL 2004-02 response and the status:

Status of Unit 1 activities referenced in GL response to accomplish commitment

1. Walkdown of containment for final design change input and confirm latent debris figure. [COMPLETE]

2. Perform debris generation analysis. [COMPLETE]
3. NPSH calculations for RHR and CCS pumps. Need integration of chemical effects testing into head loss calculations and subsequent input to NPSH calculations. Anticipated date of finalized NPSH calculations Dec. 31, 2007. Current calculations indicate adequate NPSH was available for current licensing basis; that is, new screen design with 50 percent blocked assumption. **[OPEN]**
4. Verification testing of screen size. [COMPLETE]
5. Downstream effects analysis. [COMPLETE]
6. Screen installation for Unit 1 - 2007 fall outage. Verified complete by resident inspectors at end of outage. [COMPLETE]
7. Modifications needed for RHR Back up seals? Determined not to be required. [COMPLETE]
8. Remove tags, labels, etc. from containment not qualified for LOCA environment. Alternate action taken to removal; inventory unqualified labels, tags, etc. and account for potential blockage in debris bead head loss criteria. Procedure change prevents increase in inventory of tags, labels, etc. in containment. [COMPLETE]
9. Revision of procedure to control labels and signs in containment. [COMPLETE]
10. Increase area of screens to account for chemical effects. ALTERNATE: Results of chemical effects analysis to be incorporated into head loss testing and subsequently input to NPSH calculations. **[OPEN]**
11. Program change to assure mechanistic analysis assumption related to insulation remain valid. **[OPEN]**
12. Update licensing basis to reflect actions taken in response to GL 2004-02. To be done at end of 2007 via change to modification DCP to change the appropriate licensing base documents. **[OPEN]**
13. Modification to HHSI throttle valves. [COMPLETE]

TI 2515/166 remains open for Unit 1 pending review of the status of the above open commitment items during the first quarter of 2008.

<u>Status of Unit 2 actions not complete at previous Unit 2 TI 2515/166 inspection - Spring 2007</u>:

1. Finalized NPSH calculations for RHR and CS pumps. To be completed when chemical effect analysis results can be input to screen head loss analysis and testing and then into NPSH calculations. [**OPEN]**
2. Debris generation analysis. [COMPLETE]
3. Debris transport analysis. [COMPLETE]
4. Chemical effects analysis. [**OPEN**]
5. Program controls related to containment coatings. [COMPLETE]
6. Modification to HHSI throttle valves. Extension for fall outage of 2008 to complete. **[OPEN**]

TI 2515/166 remains open for Unit 2 pending review of the status of the above open commitment items during the first quarter 2008.

.2 <u>(Closed) URI 05000364/2007002-01, Failure of RHR Containment Sump Isolation Valve to Open on Demand</u>

On May 4, 2007, the NRC completed the onsite portion of a special inspection related to the circumstances surrounding the failure of RHR Containment Sump Isolation Valve MOV-8811A. This inspection identified apparent violation (AV) 05000364/2007009-01, Failure to Promptly Identify and Correct a Condition Adverse to Quality for RHR Pump 2A Containment Sump Suction Valve. A Final Significance Determination for a Yellow finding and Notice of Violation (NRC Inspection Report Nos. 05000348/2007011 and 05000364/2007011) was issued on October 31, 2007.

4OA6 <u>Meetings, Including Exit</u>

On January 10, 2008, the inspectors presented the inspection results to Mr. Randy Johnson and the other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information provided by the licensee was returned to the licensee at the completion of the inspection.

4OA7 <u>Licensee-Identified Violations</u>

The following finding of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meet the criteria of Section IV of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- TS 5.4.1 requires written procedures to be established, implemented, and maintained covering the activities of RG 1.33, Revision 2, Appendix A, February 1978. Appendix A of RG 1.33 states, in part, that maintenance which can affect the performance of safety-related equipment should be properly pre-planned and performed in accordance with written procedures. Station procedure FNP-1-STP-34.1, "Containment Inspection (Post-Maintenance) requires all tools/equipment to be removed from containment or documented as a deficiency/conditions for removal/resolution prior to containment close-out. The procedure list acceptance criteria which includes: "no loose debris (rags, trash, clothing, etc.), temporary signs/postings, deficiency tags, or fibrous materials (lagging, insulation, fiberglass-reinforced tarps, etc.) are present in containment which could be transported to the containment sump and cause restriction of pump suctions during LOCA conditions." Contrary to this requirement, on October 1, 2007, licensee personnel carried two 11 foot by 5 foot fiberglass-reinforced tarps into the Unit 1 containment with the unit in Mode 3. One of the tarps was taped to the floor grating above the refueling transfer canal and the workers exited containment. This event is documented in CRs 2007109419 and 2007109414. This finding is of very low safety significance because the tarp and tape used to attach it to the floor grating only had the potential to partially block one containment sump (less than 50 percent blockage).

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
W. R. Bayne, Performance Analysis Manager
S. H. Chestnut, Engineering Support Manager
C. L. Collins, Plant Manager
L. Hogg, Security Manager
J. Horn, Training and Emergency Preparedness Manager
J. Jerkins, Performance Analysis Engineer
R.J. Johnson, Site Vice President
T. Livingston, Chemistry Manager
B. Moore, Site Support Manager
W. Oldfield, Quality Assurance Supervisor
C. Peters- Health Physics Manager
J. Swartzwelder, Work Control Superintendent
C. Thornell, Maintenance Manager
R. Vanderbye, Emergency Preparedness Coordinator
R. Wells, Operations Manager

NRC personnel
S. Shaeffer, Division of Reactor Projects, Branch Chief

LIST OF ITEMS OPENED AND CLOSED

Opened		
05000348,364/2007005-01	URI	Potential Flooding of Containment Sump Suction Valves. (1R06)
Opened and Closed		
05000348,364/2007005-02	NCV	Failure to Adequately Assess Risk Resulting in Unit 2 Reactor Trip (4OA2.2)
05000364/2007005-03	NCV	Failure to Maintain Two ECCS Trains Operable Due to Gas Accumulation In the Charging Pump Suction Piping (4OA3.2)
Closed		
05000364/2007-001-00	LER	Unit 2 Reactor Trip during Unit 1 Main Generator Differential Lockout Relay Testing (4OA3.1)
05000364/2005-001-00	LER	Gas Binding of the Unit 2 ‘A’ Train HHSI Pump (4OA3.2)
05000348/2007-001-00	LER	Technical Specification 3.8.1 Violation Due to Failure of Breaker/Mechanism-Operated Cell (MOC) Switch (4OA3.3)

05000348/2006-002-00	LER	Main Steam Isolation Valve Failure to Close (4OA3.4)
05000364/2007-002-01	URI	Failure of RHR Containment Sump Isolation Valve to Open on Demand (4OA5.2)

LIST OF DOCUMENTS REVIEWED

<u>Section 1R02: Evaluation of Changes, Tests, or Experiments</u>

<u>Full Evaluations</u>

DCP 1040671101,DCP 1050912301, DCP 1061314201,DCP 29979928201, DCP 98293780006, MDC 2070814102

<u>Screened Out Items</u>

DCP-1979920001,DCP 1999954001, DCP 2029983301, DCP 2050912001, ED 1070711601, ED 1070776501, ED 1071846401, ED 2052911301,ED 2070292701, ED C052713101, ED C070550601, ED C072134101, ED C072232201

<u>Procedures</u>

NMP-AD-010, 10 CFR 50.59 Screenings and Evaluations, Version 2.0
NMP-AD-008, Applicability Determinations, Version 2.0
NMP-ES-034, Equivalency Determinations, Version 1.0

<u>Calculations</u>

MC-F-07-0018, Containment Sump Levels During Recirculation, Version 5

<u>Other Documents</u>

U418485A, Containment Cooler Type 304 SS Replacement Coils-Performance Data & Operating Instruction for Performance Software, 6/30/2000

<u>Section 1R04: Equipment Alignment</u>

<u>Drawings</u>

175002 Sheet 1, Revision 47
175002 Sheet 2, Revision 25
175002 Sheet 3, Revision 13
175038 Sheet 1, Revision 37
175038 Sheet 2, Revision 20

<u>Procedures</u>

FNP-1-SOP-7.0, Residual Heat Removal System, Version 75.0
FNP-1-SOP-23.0, Component Cooling Water System, Version 65.0

Technical Specifications 1.1, 3.4.7, 3.4.8

<u>Section 1R05: Fire Protection</u>

<u>Plant Drawings</u>

A-508650, Sheet 10, Revision 3
A-508650, Sheet 5, Revision 1
A-508650, Sheet 46, Revision 2

A-508650, Sheet 47, Revision 3
A-508650, Sheet 48, Revision 1
A-508650, Sheet 49, Revision 1
A-509018, Sheet 20, Revision 16

Section 1R06: Flood Protection Measures
Calculations: BM-99-1932-001, CCN-F-06-0623
Condition Reports: 2007108686, 2007111235, 2007111650, 2007112149, 2007111180, 2007111580

Section 1R08: Inservice Inspection (ISI) Activities
Condition Reports: 2007101392, 2007109644, 2007105791, 2006103856
Action Items: 2007200707, 2007200831, 2007200832, 2007204597
Procedures
FNP-0-ETP-4495, Farley Nuclear Plant Engineering Technical Procedure Non-Code Repair of ASME Code Class 2 and 3 Moderate Energy Piping (Generic Letter 90-05 or Code Case N-513-1 Evaluation, Version 3.0
FNP-0-ETP-4496, Farley Nuclear Plant Engineering Technical Procedure Corrosion Assessment, Version 2.0
FNP-1-ETP-262, Farley Nuclear Plant Engineering Technical Procedure CVCS Leakage Assessment, Version 13
MRS-SSP-2155, Farley Unit 1 Structural Weld Overlay Field Service Procedure, Revision 1
NMP-ES-024-502, PDI Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds (PDI-UT-1), Revision D
NMP-ES-024-502, PDI Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds (Appendix VIII), Version 2.0
PDI-GL-001, Performance Demonstration Initiative, Guideline for Hands-on Practice, Revision A

Other Records
ALA-07-127, Letter from Westinghouse Electric Company to Mr. J. R. Johnson, Vice President Farley Project, “Evaluation of Deposit Observed at the Pressurizer/Penetration Interface,” 10/12/2007
Certificate of Compliance, Special Metals, Heat NX0B66TY, 8/14/2007
Certificate of Compliance, Weldstar, Heat XT8637, 4/4/2007
Certificate of Conformance No. 900756-01, PCI Energy Services, Heat XT8637, Heat NX0B66TY, 9/4/2007
Certification of Tests, Arcos Industries, LLC, Heat XT8637, 4/4/2007
EVAL-06-34, Applicability Determination Checklist, Farley Unit 1 Spring 2006 Outage Steam Generator Secondary Side Loose Parts, Revision 0, 5/5/2006
Farley 1R20, Condition Monitoring Assessment and Operational Assessment, April 2006
Farley Unit 1 Inservice Inspection Report, Refueling 20, Interval3, Period 3, Outage 2, 8/7/2006
FNP-0-ETP-4496 Leak Evaluation, Leak 3025, 10/7/2007
FNP-1-M-043, FNP-1 Relief Request RR-35, Hydrostatic Testing of of Class 3 portions of buried piping, 2nd ISI Interval
FNP-1-M-096, Farley Unit 1, Third 10-year Interval, Relief Request No. RR-25, Buried portions of Class 3 Service Water Piping

Intracompany Correspondance, File: NFP9, Log: MI-07-1574, From Jeffrey A. Williams to Steve H. Chesnut, "MIS-Materials Group Review of the FNP 1R21 SG Degradation Assessment," 9/27/2007
Intracompany Correspondance, File: RER 1071449101, Log: PS-07-1312, From D. P. Hayes to S. H. Chesnut, "Joseph M. Farley Nuclear Plant - Unit 1 Generic Letter 90-05 Evaluation of Service Water Leak - Bypass Strainer," 6/22/2007
Intracompany Correspondance, From Mandy Ludlam to File, "Response to NRCIN 2006-27: Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors," 2/23/2007
Krautkramer Transducer Certificate of Conformity, UT transducer 01FKL8, 6/14/2006
Krautkramer Transducer Certification, UT transducer 00V31H, 5/23/2002
Letter from J. M. Hall (Westinghouse) To L. W. Stern, "Evaluation of Secondary Side Loose Objects Found in the Farley Unit 1 SGs," May 5, 2006
Letter from Pace Analytical to Mr. John Barkich (Westinghouse Electric Company), "Swipe/MISC-solid Characterization; Purchase Order No. 115581-0160 Pressurizer Penetration Residue Analysis; Nuclear Services Division Pace Project Number 07-4959," 10/9/2007
NL-06-1713, Letter from Southern Company to US NRC, Farley Proposed Alternative for Application of Pressurizer Nozzle Full-Structural Weld Overlays, 8/10/2006
NL-07-1608, Letter from Southern Nuclear Operating Company to USNRC, "Request for Relief, RR-55 Temporary Non-Code Repair of Service Water Piping," 10/10/2007
NMP-ES-024-511, Ultrasonic Thickness Examination Procedure, Report for Farley 1, 36" elbow in the Service Water System, 6/12/2007
NRC Memorandum From Terence Chan to Evangelos Marinos, Farley Units 1 and 2 and Vogtle Units 1 and 2: Safety Evaluation of Proposed Alternative to Apply Weld Overlays to Dissimilar Metal Welds of Pressurizer Nozzles, 2/28/2007
NSAL-06-8, Westinghouse Electric Company, Nuclear Safety Advisory Letter, "Pressurizer Heater Sleeve Cracking," Revision 1
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PCI Energy Services PQR 770, Revision 1, 6/30/2006
PCI Energy Services Welding Procedure Specification, 3-8/52-TB MC-GTAW-N638, Revision 7, 2/7/2007
PCI Energy Services Weld Procedure Supplement for WPS 3-8/52-TB MC-GTAW-N638, Revision 0, 8/13/2007
PCI Procedure Qualification Record (PQR) 750, Revision 1, 4/9/2005
Quality Release and Certificate of Conformance, Westinghouse Electric Co LLC, Heat NX0B66TY, Heat XT8637, 9/4/2007
SII006-06-04-10458-1, Laboratory Testing Inc, Certified Test Report Ultragel II, Batch 06125, 4/17/2006
WCAP 15988 Gap Analysis, 2/20/2006
Weld Overlay Process Traveler 900756-4500 (Pressurizer Surge Nozzle Overlay), Revision 1

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Miscellaneous
Farley Maintenance Rule Report dated October 19, 2007
Farley Unit 1 and Unit 2 System Health Reports for Instrument Air dated 2nd quarter 2005 through 3rd quarter 2007
Maintenance Rule Expert Panel #75 Technical Evaluation for 1B Instrument Air Dryer
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Selected Farley Unit 2 Control Room logs dated from December 2005 through December 2007
Procedures: FNP-2-SOP-31.0, Compressed Air System, Version 58.0
Work Orders:1070506701 1070506801 1070506901 1070507001 1070507101 1070507201 2062981801 2070507301 2070507401 2070507501 2070507601 2070507701 2070507801 2071843901

Section 1R17: Permanent Plant Modifications
Action Items: 200700541, 200700549
Condition Report: 2007100142
Work Orders: 2062277901, 2070508102, 2070508103

Design Change Packages
DCP 1040671101, Negative Rate Trip Removal, 9/15/04
DCP 1053131101, Replacement of 1B MDAFW Pump Motor, 5/12/06
DCP C063531801, DG Heat Exchanger Material Change, 5/12/07

Calculations
MC-F-07-0024, PROTO-HX Small and Larger Diesel Generator Heat Exchanger Models, Version 2

Procedures
NMP-AD-010, 10 CFR 50.59 Screenings and Evaluations, Version 2.0
NMP-AD-008, Applicability Determinations, Version 2.0
NMP-ES-034, Equivalency Determinations, Version 1.0

CR 2006106181
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Other Documents
ALA-04-105, Power Range Neutron Flux High Negative Rate Trip Deletion, 7/30/2004
RER 01-063, Rev. 0, Unit 1 Main Xfmer Cooling System Xfmer Tap Change, Rev. 0
TM-1062180801, Tap Setting Adjustment for Unit 1 #2 Main Power Transformer, Rev. 0
TM-1062180901, Tap Setting Adjustment for Unit 1 #1 Main Power Transformer, Rev. 0

Section 1R19: Post Maintenance Testing
CRs: 2007108843, 2007109319, 2007109900, 2007110448, 2007110520, 2007110761, 2007111205, 2007111208, 2007111222, 2007111233, 2007111290, 2007111457

Procedures:
FNP-0-EMP-1501.17, Testing, Analyzing and Troubleshooting Motor-Operated Valves Using Crane Nuclear, Universal Diagnostic Systems (UDS) and MC2 Testing Systems

FNP-0-PMT-0.0, Post-Maintenance Test Program
FNP-0-SOP-38.0, Diesel Generators
FNP-1-STP-22.16, Turbine Drive Auxiliary Feedwater Pump Quarterly Inservice Test (Tavg ≥ 547°F)
FNP-1-STP-24.16, CNTMT CLR and RCP MTR Air CLR Service Water Valves Inservice Test
FNP-1-STP-30.0B, Solid State Protective System Train B Operability Test
FNP-1-STP-40.0, Safety Injection with Loss of Off-Site Power Test
FNP-1-STP-45.2, Reactor Vessel Head Vent Valves Operability Test
FNP-1-STP-45.5, RHR Cold Shutdown Valves Inservice Test
FNP-1-STP-73.6, Verification of Reactor Head Vent Valve Operation From the Hot Shutdown Panel
FNP-1-STP-627, Local Leak Rate Testing of Containment Penetrations
WOs: 1060366601, 1060369101, 1060369401, 1060372501, 1060432101, 1061935201, 1072066401, 1072506001, 1072658201, 1072658301, 1072660101, 1072684001, S072120101, S072139901, S072205301

Section 1R20: Refueling and Other Outage Activities

Calculation

Southern Nuclear Design Calculation 036.B, Analysis of Containment Operating Deck for Heavy Load Drops - NUREG 0612

Procedures

FNP-0-ACP-47.3, Outage Preparation
FNP-0-AP-52, Equipment Status Control and Maintenance Authorization
FNP-0-AP-94, Outage Nuclear Safety
FNP-0-ETP-3643, Verification of Rod Control System Availability
FNP-0-UOP-4.0, General Outage Operations Guidance
FNP-1-IMP-201.45, Refueling Reactor Coolant System Level Calibration Q1B21FT0416
NMP-MA-007-001, SNC Rigging and Lifting Program Planning and Evaluation
NMP-MA-007-009, SNC Rigging and Lifting Program Plant Farley Specifics
FNP-1-MP-11.4, Reactor Polar Crane - Operating and Safe Load Path Instructions
FNP-1-SOP-1.3, Reactor Coolant System Filling and Venting-Vacuum Method
FNP-1-SOP-1.6, Draining th Reactor Coolant System
FNP-1-STP-18.4, Ctmt Mid-Loop and/or Refueling Integrity Verification and Ctmt Closure
FNP-1-STP-29.6, Calculation of Estimated Critical Condition
FNP-1-STP-35.0, Reactor Coolant System Pressure and Temperature/Pressurizer Temperature Limits Verification
FNP-1-STP-35.1, Unit Startup Technical Specification Verification
FNP-1-STP-101, Zero Power Reactor Physics Testing
FNP-1-UOP-2.1, Shutdown of Unit From Minimum Load to Hot Standby
FNP-1-UOP-2.2, Shutdown of Unit From Hot Standby to Cold Shutdown
FNP-1-UOP-4.1, Refueling Outage Operation
FNP-1-UOP-4.3, Mid-Loop Operations

Section 1R22: Surveillance Testing

CR 2007111289

Procedure:
FNP-1-ETP-4472.0, Containment Purge Exhaust Filtration Performance Test
FNP-1-ETP-4472.1, Containment Purge Exhaust Filtration Charcoal Adsorber Sampling & Testing

FNP-1-STP-22.16, Turbine Drive Auxiliary Feedwater Pump Quarterly Inservice Test (Tavg ≥ 547°F)
FNP-1-STP-627, Local Leak Rate Testing of Containment Penetrations

FNP-2-STP-9.0, RCS Leakage Test
FNP-2-STP-22.1, 2A Auxiliary Feedwater Pump Quarterly Inservice Test
WOs: 1060432101, 1060537401, 2060848201

Section 1R23: Temporary Plant Modifications
Action Item: 2007202740
CRs: 2007104607, 2007104614, 2007104572, 2007105238
WOs: 2060968202, 2071002901
Miscellaneous:
FNP-0-AP-8, Design Modification Control, Revision 40.0
MDC 1072506601, Torque-Seated to Limit-Seated Conversion for MOVs Q1P16MOV3131, 3134, and 3135

Section 4OA1: Performance Indicator Verification
FNP-0-AP-54, Preparation and Reporting of NRC Performance Indicator Data and NRC Operating Data, Version 9.0
Licensee Event Report 2007-003-00, Component Cooling Water Pump Breaker Failures
Selected Unit 1 Control Room Logs, January 2007 through December 2007
Selected Unit 2 Control Room Logs, January 2007 through December 2007
Selected Unit 1 and Unit 2 MSPI Derivation Reports, High Pressure Injection System, Unavailability Index, January 2007 through December 2007
Selected Unit 1 and Unit 2 MSPI Derivation Reports, Residual Heat Removal System, Unavailability Index, January 2007 through December 2007

Section 4OA2: Identification and Resolution of Problems
CRs: 2005108436, 2006105359, 2006105386, 2006108584, 2007104856, 2007105099, 2007108838, 2007109414, 2007109419, 2007109644, 2007109659, 2007110411, 2007110562, 2007110448, 2007110520, 2007110563, 2007110736, 2007110761, 2007111304, 2007111522

Procedures:
FNP-1-EMP-2541.01, N1N31RLYGEN1HEA Main Generator Differential Lockout Relay Function Test
FNP-1-SOP-1.6, Draining the Reactor Coolant System
FNP-1-STP-34.1, Containment Inspection (Post Maintenance)
FNP-1-STP-40.1, A Train Sequence Operability and Load Shedding Circuit Test

Section 4OA3: Event Followup
Action Items: 2006200151, 2006200165, 2006200166, 2006200167, 2006200168, 2006200170, 2006200172, 2006200174, 2006200185, 2006202163, 2006202164
CR: 2005112351

Farley Unit 2 Isometric Drawings:
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D515343, Sheet 1, Revision 1
D515398, Sheet 1, Revision 0
D515418, Sheet 1, Revision 1
D515947, Sheet 1, Revision 1

Miscellaneous:
Calculation Note FAI/07-40 Rev 0, "Analysis of Hydrogen Gas Accumulation Using Farley Plant Data", 6/07/2007
Documentation of Engineering Judgement, DOEJ-SM-2072034501-001, "Potential for Hydrogen Gas Transport from the 2A High-Head Safety Injection (HHSI) Pump Suction to the 2B HHSI Pump Suction", 8/07/2007
Intracompany Correspondance, File: RER 1051731701, Log: PS-06-0196, From M. J. Ajluni to S. H. Chesnut, "Joseph M. Farley Nuclear Plant - Unit 2 Hydrogen Accumulation - 2A Charging/HHSI Pump", 2/02/2006
Licensee Event Report 2005-001-00, "Gas Binding of the Unit 2 A Train High Head Safety Injection Pump"

Procedures:
FNP-2-SOP-2.1, Chemical and Volume Control System Plant Startup and Operation, Version 86.0
FNP-2-SOP-2.5, RCS Chemical Addition, VCT Gas Control, and Demineralizer Operation, Version 51.0

Section 4OA5: Other
Calculations:
0000-0067-8648, Farley 1&2 Debris Loading Force Calculation, Rev. 1
2005-04800, Debris Generation and Transport Analysis in Support of Resolution GSI-191, dated 6/14/07
2005-06360, Head Loss Calculation Supporting Resolution of GSI-191, dated 9/21/05
CN-SEE-111-07-04, Farley Unit 1 HHSI Throttle Valves Replacement, Rev. 0
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SC-1050912301-001, Elevator No. 3 Load Drop Investigation, Rev. 1
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Miscellaneous:
CDI Technical Note 07-36, Farley Nuclear Power Station Module Head Loss Testing Data Report, dated 10/18/07

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Document No. 10508123001, 10 CFR 50.59 Screening/Evaluation for Containment Sump Screen Modifications, Unit 1, dated 8/24/07
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GE dDRF 0000-0055-99111, Farley Module Test Flowrate and Debris Mass Calculation, 10/07

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FNP-0-AP-25, Equipment Identification and Labeling, dated 8/13/07
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