UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

January 15, 2003

Southern Nuclear Operating Company, Inc.
ATTN: Mr. H.L. Sumner, Jr.
Vice President - Hatch Plant
P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: EDWIN I. HATCH NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT 50-321/02-05, 50-366/02-05

Dear Mr. Sumner:

On January 4, 2003, the Nuclear Regulatory Commission (NRC) completed an inspection at your Hatch Units 1 and 2. The enclosed integrated inspection report documents the inspection findings which were discussed on January 8, 2003, with Mr. P. Wells 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 two NRC-identified findings and one self-revealing finding of very low safety significance (Green) that were determined to involve violations of NRC requirements. However, because of the very low safety significance and because the violations were entered into your corrective action program, the NRC is treating these three violations as Non-Cited Violations (NCVs) in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you contest any NCV contained in the enclosed inspection report, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, 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 Edwin I. Hatch Nuclear Power Plant.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available 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/

Brian R. Bonser, Chief
Reactor Projects Branch 2
Division of Reactor Projects

Docket Nos.: 50-321, 50-366
License Nos.: DPR-57, NPF-5

Enclosure: Integrated Inspection Report
50-321/02-05, 50-366/02-05
w/Attachment

cc w/encl: (See page 3)

cc w/encl:
J. D. Woodard
Executive Vice President
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

P. H. Wells
General Manager, Plant Hatch
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

Raymond D. Baker
Manager Licensing - Hatch
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

Ernest L. Blake, Esq.
Shaw, Pittman, Potts and
Trowbridge
2300 N Street, NW
Washington, D. C. 20037

Office of Planning and Budget
Room 610
270 Washington Street, SW
Atlanta, GA 30334

Director
Department of Natural Resources
205 Butler Street, SE, Suite 1252
Atlanta, GA 30334

Manager, Radioactive Materials Program
Department of Natural Resources
Electronic Mail Distribution

Chairman
Appling County Commissioners
County Courthouse
Baxley, GA 31513

Resident Manager
Oglethorpe Power Corporation
Edwin I. Hatch Nuclear Plant
Electronic Mail Distribution

Charles A. Patrizia, Esq.
Paul, Hastings, Janofsky & Walker
10th Floor
1299 Pennsylvania Avenue
Washington, D. C. 20004-9500

Senior Engineer - Power Supply
Municipal Electric Authority
of Georgia
Electronic Mail Distribution

Distribution w/encl: (See page 4)

<u>Distribution w/encl</u>::
L. Olshan, NRR
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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-321, 50-366
License Nos:	DPR-57, NPF-5
Report No:	50-321/02-05, 50-366/02-05
Licensee:	Southern Nuclear Operating Company, Inc. (SNC)
Facility:	E. I. Hatch Nuclear Power Plant, Units 1 & 2
Location:	P.O. Box 2010 Baxley, Georgia 31515
Dates:	September 29, 2002 - January 4, 2003
Inspectors:	J. Munday, Senior Resident Inspector, Reactor Projects Branch 2 N. Garrett, Resident Inspector, Reactor Projects Branch 2 C. Rapp, Senior Project Engineer, Reactor Projects Branch 2 (Section 1R06) J. Wallo, Security Inspector, Plant Support Branch (Section 4OA5.1) P. Vandoorn, Senior Reactor Inspector, Engineering Branch 2 (Sections 1R02 and 1R17) M. Scott, Senior Reactor Inspector, Engineering Branch 2 (Sections 1R02 and 1R17) S. Walker, Reactor Inspector, Engineering Branch 2 (Sections 1R02 and 1R17) W. Bearden, Reactor Inspector, Engineering Branch 2 (Section 1R12)
Approved By:	Brian R. Bonser, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000321/2002-005, IR 05000366/2002-005; Southern Nuclear Operating Company, Inc.; 09/29/2002 - 01/04/2003; Edwin I. Hatch Nuclear Plant, Flood Protection, Operability Evaluations, and Event Followup.

The report covered a three month period of inspection by resident inspectors and announced inspections by a regional security inspector and regional reactor inspectors. Three Green non-cited violations (NCVs) were identified. The significance of most findings in indicated by their color (Green, White, Yellow, Red) using IMC 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

- Green. The licensee had not taken prompt corrective action to replace missing Residual Heat Removal Service Water (RHRSW) piping penetration seals at the intake structure.

  A non-cited violation of 10CFR50 Appendix B, Criterion XVI was identified. This finding is more than minor because the lack of penetration seals could have permitted the Plant Service Water (PSW) valve pit to flood and affected the mitigating systems cornerstone. Because flooding of the PSW valve pit had not occurred nor were flooding conditions present, this failure to promptly correct a condition adverse to quality is of very low safety significance. (Section 1R06)

- Green. An incorrect calculation constant resulted in a non-conservative setpoint for the Unit 1 main steam line flow - high isolation setpoint.

  A self-revealing non-cited violation of Technical Specification (TS) table 3.3.6.1-1 was identified. This finding is greater than minor because the actual setpoint exceeded the TS allowable value and the analytical limit, as a result of the error. However, the violation is of very low significance because the increased steam released due to the higher setpoint would not significantly impact offsite radiological dose during a main steam line break accident. (Section 4OA3.2)

- Green. The licensee did not promptly identify the cause of a failed safety relief valve (SRV). An operability evaluation written in response to the failure was not timely and did not adequately support a determination that the remaining SRV's were operable. Consequently, this significant condition adverse to quality was not promptly corrected and adequate measures were not taken to preclude repetition.

A non-cited violation of 10CFR50 Appendix B, Criterion XVI was identified. This finding is greater than minor because the licensee's operability assessment was not timely and relied primarily on unsupported engineering judgement for a determination of operable for the remaining SRV's. It also required multiple revisions when inconsistencies were identified by the inspectors. This finding was of very low significance because no loss of SRV function occurred. (Section 4OA5.1)

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

On September 30, the Unit 1‘A’ and ‘B’ reactor recirculation motor generator (RRMG) sets tripped due to oil filter fouling and a subsequent decrease in oil pressure. Reactor power decreased to approximately 33% rated thermal power (RTP). Following repairs the unit was returned to 100% RTP on October 1. On October 10, the unit was shutdown to replace three main steam safety relief valves. The unit was restarted on October 14 and operated at 100% RTP, except for planned maintenance and testing, during the remainder of this inspection period.

On October 11, Unit 2 reduced power to approximately 50% RTP due to a reduction in main condenser vacuum when two offgas valves malfunctioned. The valves were repaired and power was restored to 100% RTP later that day. The unit operated at 100% RTP, except for planned maintenance and testing, during the remainder of this inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors performed a review of the cold weather and freeze protection system associated with the emergency diesel generators (EDGs), plant service water (PSW) system, condensate storage tanks, the intake structure, and fire protection system. The inspectors reviewed the licensee’s freeze protection procedure, DI-OPS-36-0989N, Cold Weather Checks, and used the most recently completed preventive maintenance checklist from 52PM-MEL-005-0S, Cold Weather Checks, for cold weather preparation to assess the system readiness for cold weather and the status of system deficiencies. In addition, on November 6 and November 12 the inspectors observed the licensee’s response to tornado warnings in Jefferson Davis and Appling Counties to assess their implementation of procedure 34AB-Y22-002-0, Naturally Occurring Phenomena.

b. Findings

No findings of significance were identified.

1R02 Evaluations of Changes, Tests or Experiments

a. Inspection Scope

The inspectors reviewed evaluations for eight changes to confirm that the licensee had appropriately considered the conditions under which changes to the facility or procedures may be made, and tests conducted, without prior NRC approval. The inspectors reviewed additional information such as calculations, supporting analyses, the Updated Final Safety Analysis Report (UFSAR), and drawings. The eight evaluations reviewed are listed in the Attachment.

The inspectors also reviewed samples of changes such as design changes, commercial grade dedication packages, a temporary modification, and a procedure change 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 10 CFR 50.59. The 15 "screened out" changes reviewed are listed in the Attachment.

The inspectors also reviewed a recent audit of the 10CFR50.59 process to confirm that problems were identified at an appropriate threshold, were entered into the corrective action process, 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 walkdowns of the following six systems to verify the availability of redundant or diverse systems, and components and to verify that defense-in-depth was maintained during periods when safety equipment was inoperable. The inspectors compared system configuration to the associated licensee procedures and system and component checklists to verify systems and components were correctly aligned. Additionally, the inspectors reviewed selected Condition Reports (CRs) to verify that equipment alignment issues were being identified and adequately resolved. Plant procedures and documents reviewed are listed in the Attachment.

- 2A, 2C, and 2D Residual Heat Removal Service Water (RHRSW)
- 1B, 1C, 2A, and 2C EDGs
- 1A, 1B, 2A, and 2C EDGs
- 2B, 2C, 2D PSW
- 2A, 2B, 2D RHRSW
- 2B and 2D Residual Heat Removal (RHR)

Complete System Walkdown: The inspectors conducted a detailed review of the alignment and condition of the Unit 1 High Pressure Coolant Injection (HPCI) system. The inspectors compared actual system configuration to the associated licensee procedures, and system and component checklists to verify systems and components were correctly aligned. In addition, the system was walked down to verify that hangers and supports were functional and in good mechanical condition and the support systems were functional. The inspectors also reviewed the system health report, CRs, and Maintenance Work Orders (MWOs) associated with the system to verify that issues were being appropriately resolved. Plant procedures and documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors toured seven risk significant areas, identified in the licensee's Independent Plant Evaluation for External Events, to assess the material condition of the fire protection and detection equipment and to verify fire protection equipment was not obstructed. The inspectors reviewed licensee procedure 40AC-ENG-008-OS, Fire Protection Program, and conducted area walkdowns to assess the licensee's control of transient combustibles. The inspectors also reviewed the Site Fire Hazards Analysis and Pre-fire Plan drawings, A-43965, sheets 23B and 25B, to verify that the necessary fire fighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, was in place. The fire areas inspected included the following:

- Unit 1 RPS Room and Vertical Cable Vault, Fire Area 1013
- Unit 2 RPS Room and Vertical Cable Vault, Fire Area 2013
- Unit 1 and 2 Vertical Cable Vault, Fire Area 0040
- Control Building Access, Fire Area 0014K
- Unit 1 600 Volt Switchgear Room 1D, Fire Area 1017
- Unit 2 600 Volt Switchgear Room 1C, Fire Area 2016
- Control Building Elevation 112', Fire Area 0001

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed the licensee's internal and external flooding mitigation procedures and equipment to verify they were consistent with the licensee's design requirements and risk analysis assumptions. For internal flooding, the inspectors reviewed the UFSAR and the Individual Plant Examination and walked down the areas listed below which contained risk-significant structures, systems and components below flood level to verify flood barriers were in place. Water-tight doors were observed to verify they were closed as required by licensee procedures, the locking mechanisms functioned properly, and the sealing gasket material was intact and undamaged. The inspectors reviewed selected alarm response procedures to verify alarm setpoints and setpoints for sump pump operation in areas vulnerable to flooding were consistent with the UFSAR, the setpoint index, and Technical Specifications (TS).

The inspectors discussed external flooding preparation with engineering personnel to verify preparation and compensatory measures met the licensee's design requirements and risk analysis assumptions. The inspectors checked selected cable tunnels to verify the sump pumps functioned and adverse water conditions did not exist.

The inspectors reviewed a sampling of CRs to verify the licensee was identifying and correcting problems associated with flood detection and protection of SSCs. Licensee documents and drawings reviewed during the inspection are listed in the Attachment. Areas walked down included the following:

- Intake Structure
- Unit 1 Vital Battery Rooms
- Unit 2 Vital Battery Rooms
- Unit 1 Condensate Pumps

b. Findings

Introduction: A finding was identified in that the licensee had not taken prompt corrective action to replace missing RHRSW piping penetration seals at the intake structure.

Description: These penetration seals are required by the Unit 2 UFSAR to prevent high level in the intake bay from flooding the PSW valve pit. The penetration seals were described as welded steel plates over both ends of the penetration. The missing penetration seals were documented in CR 2000004378 dated November 13, 2000. The licensee determined the UFSAR could not be revised because flooding of the PSW valve pit had not been analyzed in the UFSAR. The licensee initiated MWO 10004055 to install these penetration seals.

When developing the penetration seal, the licensee identified that the type of seal to be used was not described in the UFSAR. The licensee documented this issue CR 2001003959. The licensee subsequently determined the type of seal was acceptable and revised the UFSAR accordingly. The licensee issued MWO 10100454 on February 26, 2001, to seal in these penetrations. MWO 10004055 was canceled on December 11, 2001, referencing MWO 10100454.

During a walkdown of the intake structure on November 20, 2002, the inspectors observed that no RHRSW piping penetration seals had been installed and the condition of the penetrations was similar to those described in MWO 10100454.

Analysis: This finding is more than minor because the lack of penetration seals could have permitted the PSW valve pit to flood, which would adversely affect the PSW system function, and affected the mitigating systems cornerstone. However, because flooding of the PSW valve pit had not occurred nor were flooding conditions present, this finding is of very low safety significance. The inspectors determined this finding was indicative of a potential corrective action deficiency because of the significant delay in correcting a condition adverse to quality and is noted in Section 4OA2.

Enforcement: 10CFR50 Appendix B, Criterion XVI, Corrective Action, requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to the above, the licensee identified this condition adverse to quality in 2000, but as late November 20, 2002, had not corrected the condition. Because this failure to promptly correct a condition adverse to quality is of very low safety significance and has been entered into the Corrective Action Program (CAP) as CR 2002011958, this violation is being treated as a non-cited violation (NCV), consistent with Section VI.A.1 of the NRC Enforcement Policy, and is identified as NCV 50-321, 366/02-05-01, Inadequate Corrective Action for Missing Penetration Seals.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensed operator performance during one simulator exercise, LT-SG-50447-07, Emergency Core Cooling Strainer Clogging. The inspectors reviewed licensee procedures 10AC-MGR-019-0S, Procedure Use and Adherence, and DI-OPS-59-0896N, Operations Management Expectations, to verify formality of communication, procedure usage, alarm response, control board manipulations, and supervisory oversight. The inspectors also reviewed licensee procedure 73-EP-EIP-001-0S, Emergency Classification and Initial Actions, to verify the event action level was identified and reported correctly. The inspectors attended the post exercise critiques and discussed operator performance with the instructors to verify the licensee identified issues were comparable to issues identified by the inspectors.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

Quarterly Sample: The inspectors conducted a detailed review of the Unit 1 and 2 Hydrogen and Oxygen Sampling System, and the 18 month preventive maintenance of the 1A EDG. The inspectors performed a system walkdown and interviewed the system engineers to determine the existing system configuration and deficiencies. The inspectors reviewed the system health report, MWOs, CRs, and system modifications to assess the overall system condition and maintenance related issues. Additionally, the inspectors reviewed the licensee's Maintenance Rule (MR) reports and scoping documents to determine that the systems were properly scoped, in the proper maintenance rule category, and appropriate actions were being taken on the system. Plant procedures and documents reviewed are listed in the Attachment.

Review of Maintenance Rule Periodic Assessment: The inspectors reviewed the licensee's MR periodic assessment, dated June 27, 2002, which covered the period from June 1, 2000, until May 31, 2002. The assessment report was issued to satisfy paragraph (a)(3) of 10 CFR 50.65. The inspectors reviewed the report to determine if it was issued in accordance with the time requirements of the MR and included evaluation of: balancing reliability and unavailability; MR (a)(1) and (a)(2) activities; and use of industry operating experience. To verify compliance with 10 CFR 50.65, the inspectors reviewed selected MR activities covered by the assessment period from the following risk significant systems: 4160 VAC electrical breakers, HPCI, Reactor Core Isolation Cooling (RCIC), and RHRSW. The inspectors also reviewed selected maintenance rule activities associated with corrective actions for 4160 VAC electrical breakers and the RHRSW which were classified as MR (a)(1). Additionally, the inspectors reviewed CRs, quarterly system health reports, monthly site MR summary reports, and monthly system engineer MR reports issued during the period covered by the periodic assessment to determine if corrective actions for deficiencies were being appropriately addressed.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the following licensee Plan of the Day (POD) documents to verify that plant risk was adequately assessed prior to components being removed from service or following failure of a component. In addition, when emergent work was identified, the inspectors held discussions with licensee personnel and walked down plant systems to verify actions were taken to minimize the probability of an initiating event and maintain the functional capability of mitigating systems.

- POD for Work Week October 5 - 11, 2002
- POD for Work Week October 12 - 18, 2002
- POD for Work Week October 19 - 25, 2002
- Extension of the 1A EDG Outage during Work Week November 10 - 16, 2002
- POD for Work Week December 3 - 9, 2002

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Plant Evolutions

a. Inspection Scope

For the non-routine events described below, the inspectors reviewed operator logs, plant computer data, and strip charts to determine what occurred and how the operators responded, and to verify that the response was in accordance with plant procedures.

- On September 30, the Unit 1 ‘A’ and ‘B’ RRMG sets tripped due to low lubricating oil pressure when the lubricating oil filter became clogged. The licensee found that a series of equipment failures allowed water from the floor drain system to enter the service air system which subsequently migrated into the RRMG lubricating oil system through the air driven oil mist eliminator. Contaminants in the water caused the oil filters to clog and the RRMG sets to trip. The inspectors observed operator performance to assess the licensee’s implementation of 34AB-B31-001-02, Reactor Recirculation Pump(s) Trip, or Recirc Loops Flow Mismatch.

- On October 11, Unit 2 power was reduced to approximately 50% RTP when main condenser vacuum began to decrease due to failure of two steam jet air ejector drain valves. The inspectors observed main control room operator’s respond to the event in accordance with 34AB-N61-002-2, Main Condenser Vacuum Low.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following six operability evaluations to verify the licensee had adequately assessed TS operability. The inspectors also reviewed the UFSAR to verify the system or component remained available to perform it’s intended function. In addition, the inspectors verified compensatory measures were adequate and properly implemented.

- Unit 1 HPCI Overspeed Trip Valve 1E41-F3082, LR-REG-001-1002
- Unit 1 and 2 RHRSW Pumps Minimum Flow Valve Response Due to Loss of Air, LR-REG-007-0902
- Common Cause Failure Analysis for EDG 2C, LR-REG-010-0902
- Unexpected IRM/APRM Overlap During October 2002 Unit 1 SRV Outage, October 2002
- Standby Gas Treatment System Operability While Operating A Diesel Engine in Unit 1 Reactor Building
- 2C EDG Operability With The Cooling Water Outlet Valve, 2P41-F339B Not Full Closed, LR-REG-004-1102

b. Findings

No findings of significance were identified.

1R16 Operator Work Arounds

a. Inspection Scope

The inspectors assessed the cumulative effects of operator workarounds on the reliability, availability, and potential for mis-operation of a system to verify that there was no increased overall plant risk. This assessment included increases of initiating event frequencies, effects on multiple mitigating systems, and the ability of operators to correctly respond to abnormal plant conditions. The inspectors used the October 16, 2002 revision of the Operations Needs, Significant Work Arounds, and Work Arounds list, during this review.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

Resident Observations: The inspectors reviewed the following two modifications to determine if they adversely affected the reliability or functional capability of the associated systems. The inspectors reviewed the applicable UFSAR sections and the 10CFR50.59 assessment associated with the modification to determine if the design basis of the system was affected.

- DCR 02-033, HPCI Oil Level Switch Fuses, Unit 2
- DCR 00-026, Delete RCIC Electronic Overspeed Trip

Biennial Review: The inspectors evaluated design change request (DCR) packages and commercial grade dedication (CGD) packages for eight modifications, in the Initiating Events and Mitigating Systems cornerstone areas, to evaluate the modifications for adverse affects on system availability, reliability, and functional capability. The modifications and the associated attributes reviewed are as follows:

- DCR 99-035, Install Control Rod Drive Minimum Flow Bypass (Initiating Events)
  - Materials type/classification/pressure boundary
  - Seismic considerations
  - Functional requirements to support design bases for flow and pressure control
  - Functional test results
  - Plant procedure and critical drawing updating
  - Operations training

- DCR 99-029, Reactor Recirculation Pump and Motor Refurbishment (Initiating Events)
  - Materials/Replacement Components material compatibility, Code requirements, and seismic requirements
  - Associated temporary modification risk assessment
  - Motor cooler functional requirements
  - Inspection requirements
  - Functional test criteria and results
  - Supporting vendor analyses
  - Plant procedure and critical drawing updating
  - Operations training

- DCR 00-007, Residual Heat Removal Service Water Cutter Pumps (Mitigating Systems)
  - Post modification testing criteria and results
  - Seismic considerations
  - Pump repair and installation procedure updating

- DCR 01-66, Installation of PSW Isolation Valves (Mitigating Systems)
  - Operational pressure test criteria and results
  - Seismic considerations
  - Updating of drawings and affected plant procedures
  - Affected flowpaths of PSW to remaining loads
  - Heat Removal
  - Necessary pressure boundaries reestablished

- DCR 01-011, Recirculation Run Back on Low Level (Initiating Events)
  - Pre and post modification testing criteria and results
  - Seismic considerations
  - Operations training
  - Corrective actions for post modification problems

- TM 2-01-02, Removal of 3 Wires for Recirc Pump A LPM Nuisance Alarm (Initiating Events)
  - Removal of power / current
  - Supporting license basis and safety evaluation documentation
  - License basis documents updated

- SDC-00-6003, Jacket Cooling Setpoint Change (Mitigating Systems)
  - Emergency Diesel Generator DG trip setpoints and characteristics bounded by new setpoint
  - Response time acceptance
  - Updating of procedures reflect new setpoint
  - Testing acceptance criteria
  - Supporting vendor analyses

- CGD 02-0025, Clamp and Gusset Fabrication for RHR System (Mitigating Systems)
  - Material compatibility with original design for type, classification, and dimensions
  - Critical characteristics, acceptance criteria, and method of acceptance

For selected modification packages, the inspectors observed the as-built configuration. 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, Technical Specifications, and design basis information.

The inspectors also reviewed the results of two recent audits covering the modifications process and reviewed 13 CRs associated with modifications to confirm that problems were identified at an appropriate threshold, were entered into the corrective action process, and appropriate corrective actions had been initiated.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a, Inspection Scope

The inspectors either observed personnel performance or reviewed the test results for the following seven maintenance testing activities to verify the scope of testing demonstrated that both the work performed was correctly completed and the affected equipment was operable. The inspectors also reviewed the maintenance package to verify procedural requirements were met. The inspectors reviewed equipment status and alignment to verify the system or component was properly realigned. Plant documents reviewed are listed in the Attachment.

- MWO 20203586, Unit 2 HPCI Oil Level Switch
- MWO 10201102, 1B31-F023A, Reactor Recirculation Pump 1A, Suction Valve Torque Switch Adjustment
- MWO 10202639, 1B21-F013F, Main Steam Safety Relief Valve Replacement
- MWO 10202640, 1B21-F013L, Main Steam Safety Relief Valve Replacement
- MWO 10202641, 1B21-F013J, Main Steam Safety Relief Valve Replacement
- MWO 20203578, Troubleshoot and Repair 2C EDG Generator Field Ground
- MWO 20202166, Disassemble Check Valve 2E51F023 for Inspection

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors reviewed licensee records, conducted control room observations and observed selected maintenance and testing activities to verify the licensee’s use of risk management during the Unit 1 main steam safety relief valve replacement outage.

Monitoring of Shutdown Activities: The inspectors observed portions of the reactor shutdown, including the insertion of a manual scram, to verify implementation of licensee procedure 34GO-OPS-013-1, Normal Plant Shutdown. In addition, the reactor cooldown was monitored to verify the cooldown rates did not exceed TS requirements and that entry into shutdown cooling was in accordance with plant procedure 34SO-E11-010-1, Residual Heat Removal System.

Licensee Control of Outage Activities: The inspectors reviewed DI-OPS-57-0393N, Outage Safety Assessment, to verify the licensee was correctly maintaining required equipment in service in accordance with outage risk management. In addition, the inspectors reviewed the contingency plans and the equipment relied on for event mitigation to verify procedures and equipment were consistent with the assumptions in the Unit 1 SRV Replacement Outage Safety Assessment, October 9, 2002. In particular, the inspectors reviewed the water level control clearance, 10220214, the operating order written to control of reactor water level during the SRV maintenance, OO-01-1002S, and procedure 34AB-E11-001-1, Loss of Shutdown Cooling, to verify that means were available and mitigating methodologies were clear should shutdown cooling be lost. In addition, the inspectors verified the appropriate requirements were satisfied prior to the primary containment being opened.

Heatup and Startup Activities: The inspectors reviewed TS and licensee procedures to verify that mode change requirements were met during both shutdown and startup. Prior to plant startup, the inspectors performed a walkdown of the drywell to verify that material conditions supported plant operations. The inspectors observed portions of unit startup, plant heatup, and power ascension to verify implementation of licensee procedure 34GO-OPS-00101, Plant Startup.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the following six surveillance test procedures and either observed the test or reviewed test records to verify the test scope demonstrated the affected equipment was operable. The inspectors also reviewed for preconditioning of equipment, procedure adherence, and valve alignment following completion of the surveillance. The inspectors reviewed licensee procedure AG-MGR-21-0386N, Evolution and Pre-and Post-Job Brief Guidance, and attended selected briefings to verify procedure requirements were met.

- 42SV-TET-001-1S, Primary Containment Periodic Type B and C Leakage Test, (LLRT of SRV ‘F’, ‘J’, and ‘L’)
- 57SUV-SV-010-1, ATTS Panel 1H11-P924 Channel FT&C
- 34SV-SUV-020-0S, Process Point, Heat Balance Accuracy Check, Thermal Limit, FFT Check, And APRM Adjustment Surveillance
- 34SV-SUV-023-1, Jet Pump And Recirculation Flow Mismatch Operability

- 34SV-C41-002-1S, Standby Liquid Control Pump Operability Test
- 34SV-E11-001-1S, Residual Heat Removal Pump Operability

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following two temporary modifications (TMM) to verify the TMM met the criteria defined in licensee procedure 40AC-ENG-018-0S, Temporary Modification Control. In addition, the inspectors reviewed the 10 CFR 50.59 evaluation using the design basis information in the UFSAR to verify the modification did not affect the safety function of the system. The inspectors walked down the modification to verify it was installed in accordance with the TMM requirements.

- TM 2-02-17, Installation of Gagging Devices on the Unit 2 Residual Heat Removal Service Water Minimum Flow Valves
- TM-02-24, Instrument Air Supply to the Unit 2 B Reactor Recirculation Motor Generator Set Oil Mist Eliminator

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

d. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting performance indicators (PIs). The inspectors reviewed raw PI data collected for the PIs below from October, 2001 to September, 2002 and compared graphical representations from the most recent PI report to the raw data to verify the data was correctly included in the 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, and that the PI was calculated correctly. Additionally, the inspectors reviewed monthly operating reports and Licensee Event Reports to verify the PI data was appropriately captured for inclusion into the PI report. The inspectors compared their observations with licensee procedure, 00AC-REG-005-0S, Preparation And Reporting Of NRC PI Data, and NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Rev. 2, to verify licensee procedure requirements and industry reporting guidelines were met.

Initiating Events Cornerstone

- Unplanned Scrams
- Scrams With Loss of Normal Heat Removal
- Unplanned Power Changes

Mitigating Systems Cornerstone

- Safety System Functional Failures

Barrier Integrity Cornerstone

- Reactor Coolant System Leakage

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

Cross-Reference to PI&R Findings

Section 1R06 describes a finding for failure to promptly correct a condition adverse to quality associated with the RHRSW piping penetration seals. Since the licensee failed to promptly correct this condition, the finding is indicative of a potential corrective action deficiency.

Section 4OA5 describes a finding for failure to promptly identify, correct, and preclude repetition of a significant condition adverse to quality associated with the failure of the ‘J’ SRV . Since the licensee failed to promptly identify, correct, and preclude repetition for this condition, the finding is indicative of a potential corrective action deficiency.

4OA3 Event Followup

.1 (Closed) Licensee Event Report (LER) 50-321/2002-004: Turbine Overspeed Control Valve of the High Pressure Coolant Injection System Fails

On August 14, 2002, the HPCI system was rendered inoperable when the turbine overspeed control valve diaphragm failed. The diaphragm was replaced and the system was returned to service. The diaphragm failure was believed to be due to a manufacturing defect. The LER was reviewed by the inspectors and no findings of significance were identified. The licensee documented this failure in CR 2002008245.

.2 (Closed) LER 50-321/2002-003: Calculation Error Results in Incorrect Steam Line High Flow Setpoints

a. Inspection Scope

The inspectors reviewed the LER and CR 2002008176, which documented this issue in the corrective action program, to verify that the corrective action was appropriate. Additionally, General Electric Services Information Letter No. 438, which was referenced in the LER, and appropriate sections of the Updated Final Safety Analysis Report were reviewed to ensure the significance of the issue was accurately determined.

b. Findings

Introduction: A Green self-revealing NCV of TS table 3.3.6.1-1 was identified.

Description: Both Unit 1 and 2 setpoints for the Group 1 main steam line high flow isolation were set non-conservatively due to an incorrect setpoint calculation. The maximum Allowable Value specified in TS table 3.3.6.1-1 is 138% of rated steam flow. The setpoint calculation error resulted in a setpoint of 144% of rated steam flow which exceeded the analytical limit of 140% of rated steam flow. The licensee determined this condition existed for approximately eight years.

Analysis: The inspectors determined this finding was more than minor because the actual setpoint exceeded the analytical limit and affected the mitigating systems cornerstone. However, this violation was of very low significance because the increased steam that would be released due to the higher setpoint would not significantly impact offsite radiological dose during a main steam line break accident.

Enforcement: TS Table 3.3.6.1-1, Primary Containment Isolation Instrumentation, provided a maximum allowable value of 138% of rated steam flow. Contrary to the above, the actual setpoint was found to be 144% of rated steam flow. Because this failure to comply with Technical Specification table 3.3.6.1-1 is of very low safety significance and has been entered into the licensee's CAP as CR 2002008176, this finding is being treated as an NCV in accordance with Section VI.A.1 of the NRC Enforcement Policy. The finding is identified as NCV 50-321, 366/02-05-02. Calculation Error Results in Incorrect Steam Line High Flow Setpoints.

.3 (Closed) LER 50-321/2002-005: Water Level Transient Following Manual Reactor Scram Causes Group 2 PCIS Isolation

An expected Group 2 isolation occurred when the plant was manually scrammed as part of a planned shutdown on October 10, 2002. This planned shutdown is discussed in section 1R14.2. The inspectors reviewed this LER and did not identify any findings of significance. The licensee documented this actuation in CR 2002008245.

.4 (Closed) LER 50-321/2002-002: Technical Specification Required Plant Shutdown Because of High Unidentified Reactor Coolant System Leakage

On April 19, 2002, Unit 1 was shut down when unidentified leakage in the drywell exceeded the limits of Technical Specification Limiting Condition for Operation 3.4.4. The leakage was determined to be the result of a partially stuck open SRV, 1J, releasing steam through a failed SRV tailpipe vacuum breaker. The cause of the leaking SRV is discussed in Section 4OA5.2. The SRV tailpipe vacuum breaker failed as a result of its rapid cycling due to the leakage past the 'J' SRV. Both components were subsequently replaced and satisfactorily tested. The inspectors reviewed this LER and did not identify any findings of significance. The licensee documented the SRV tailpipe vacuum breaker failure in CR 2002008245.

4OA5 Other Activities

.1 Temporary Instruction (TI) 2515/148, Appendix A: Pre-inspection Audit for Interim Compensatory Measures (ICMs) at Nuclear Power Plants

a. Inspection Scope

The inspectors conducted an audit of the licensee's actions in response to a February 25, 2002, Order which required the licensee to implement certain interim security compensatory measures. The audit consisted of a broad-scope review of the licensee's actions in response to the Order in the areas of operations, security, emergency preparedness, and information technology as well as additional elements prescribed by the TI. The inspectors selectively reviewed relevant documentation and procedures; directly observed equipment, personnel, and activities in progress; and discussed licensee actions with personnel responsible for development and implementation of the ICM actions.

The licensee's activities were reviewed against the requirements of the February 25, 2002 Order; the provisions of TI 2515/148, Appendix A; the licensee's response to the Order; and the provisions of the NRC-endorsed NEI Implementation Guidance, dated July 24, 2002.

b. Findings

No findings of significance were identified. A more in-depth review of the licensee's implementation of the February 25, 2002 Order, utilizing Appendix B and C of TI 2515/148 will be conducted in the near future.

.2 (Closed) Unresolved Item (URI) 50-321, 366/02-04-02: Inadequate Assessment of Main Steam Safety Relief Valve

Introduction: A Green NCV was identified for failure to comply with 10CFR50 Appendix B, Criterion XVI related to an untimely and inadequate SRV operability assessment.

Description: During a reactor startup on April 19, operators noted the Unit 1 ‘J’ SRV tailpipe temperature was elevated and suspected of leaking. The operators manually cycled the SRV open then closed in an attempt to reseat the SRV and reduce the leakage. Instead, the SRV stuck partially open. The unit was later manually scrammed when drywell unidentified leakage increased beyond TS limits. The licensee identified that the ‘J’ SRV tailpipe vacuum breaker had cycled excessively due to the SRV leakage and was allowing steam to be admitted directly into the drywell.

After repairing the tailpipe vacuum breaker and replacing the ‘J’ SRV, the unit was restarted on April 22. The licensee had not determined the cause of the SRV failure prior to restart; however, the licensee justified restart on their review that no similar failures in the industry were identified. The licensee concluded that this failure was unique and replacement of the SRV was an adequate corrective action for unit restart. To demonstrate current operability, the remaining SRVs in Unit 1 were satisfactorily cycled at normal operating pressure. However, continued operability of these SRVs was not addressed by the licensee.

On June 21, the licensee issued an operability assessment for the remaining SRV’s. An inspection of the 'J’ SRV had identified that the retaining nut which holds the main stage disc stem to its actuating piston was not completely tight. This resulted in vibration induced wear of the valve internals, which eventually led to the SRV failure. The licensee concluded that “… the actual causes of the failure of the unit 'J’ SRV could not conclusively be determined, but age-related degradation is suspected.” The licensee identified that three Unit 1 SRVs and one Unit 2 SRV were potentially degraded based on their age and the lack of previous inspections. However, based on meeting the ASME Boiler and Pressure Vessel code and TS testing requirements as well as successfully cycling the Unit 1 SRVs after restart, the licensee concluded that no operability concern with these four SRVs existed. The inspectors concluded this only justified past operability and did not address continued operability of the SRVs. Further, as documented in Integrated Inspection Report 50-321, 366/2002-004, the inspectors identified several inconsistencies with this operability assessment.

On July 19, the licensee issued a second assessment which included the results from three SRV’s which were inspected during the Unit 1 refueling outage. Significant wear was observed on the disc stem threads of two of the three SRV’s. Although the SRV with only minimal stem thread wear had similar in-service time as the other two valves, the licensee concluded that “…age-related degradation of the SRV internals, resulting after loss of torque on the piston, likely contributed to its failure to open properly or to reseat…” and that “…only valves with more severe internal wear are prone to failure, a condition very rarely reached.” Although the failure was considered by the licensee to have been age related, the inspectors noted that the in-service time necessary to damage the stem and render the valve inoperable had not been determined. As a result, on August 2, the licensee issued a third operability assessment to further address this issue. While the August 2 revision provided additional inspection and technical data, the licensee’s conclusion for the cause of the ‘J’ SRV failure had not changed appreciably. However, from this additional data the licensee determined that in addition to time in service, torque between the piston and disc stem connection must be lost, and relative motion, or vibration, must be present for this failure mode to be possible. As a result, the licensee was able to define operational in-service time limits for the remaining SRV's.

Analysis: The inspectors determined this finding was more than minor because the licensee's operability assessment was not timely, relied primarily on unsupported engineering judgement, and required multiple revisions when inconsistencies were identified by the inspectors. The licensee stated in their final assessment that the June 21 assessment was "…based on input from the Event Review Team (ERT), the system engineer and corporate support personnel…" and that "…the resulting operability evaluation was built primarily on engineering judgement without documenting all the technical details used to support the operability conclusions reached in the evaluation." Regarding the July 19 assessment, the licensee stated "A subsequent operability evaluation was prepared that included more of the technical information and rationale, but still relied primarily on engineering judgement as well as plant and industry operating experience regarding the reasonable expectation that the SRVs would actuate if called upon." This finding was of very low significance because no loss of SRV function occurred. The inspectors determined this finding was indicative of a potential corrective action deficiency because a significant condition adverse to quality was not promptly corrected and adequate measures were not taken to preclude repetition and is noted in Section 4OA2.

Enforcement: The SRVs are safety-related components and serve as a boundary between the reactor coolant system and the suppression pool. The leak through the stuck open SRV constituted a breach in this boundary and was therefore considered to be a significant condition adverse to quality. 10CFR50 Appendix B, Criterion XVI requires, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In addition, for significant conditions adverse to quality, the measures shall assure that the cause of the condition and the corrective action taken preclude repetition. Contrary to the above, the licensee did not promptly identify the cause of the failure of the 'J' SRV. Consequently, this significant condition adverse to quality was not promptly corrected and adequate measures were not taken to preclude repetition. Because this failure to promptly correct and preclude repetition of a significant condition adverse to quality is of very low significance and has been entered into the CAP as CR 2002011958, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy, and is identified as NCV 50-321, 366/02-05-03, Inadequate Assessment of Main Steam Safety Relief Valve.

4OA6 Meetings, Including Exit

The inspectors presented the inspection results to Mr. P. Wells, General Manager - Nuclear Plant and the other members of licensee management at the conclusion of the inspection on January 8, 2003. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

J. Betsill, Assistant General Manager - Plant Support
E. Burkett, Operations Support Superintendent
D. Davis, Plant Administration Manager
R. Dedrickson, Operations Manager
M. Googe, Performance Team Manager
J. Hammonds, Engineering Support Manager
G. Johnson, Safety Audit and Engineering Review Supervisor
W. Kirkley, Health Physics and Chemistry Manager
J. Lewis, Training and Emergency Preparedness Manager
D. Madison, Assistant General Manager - Plant Operations
R. Reddick, Site Emergency Preparedness Coordinator
P. Roberts, Outage and Planning Manager
J. Thompson, Nuclear Security Manager
S. Tipps, Nuclear Safety and Compliance Manager
P. Wells, General Manager - Nuclear Plant

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-321, 366/02-05-01	NCV	Inadequate Corrective Action for Missing Penetration Seals (Section 1R06)
50-321, 366/02-05-02	NCV	Calculation Error Results in Incorrect Steam Line High Flow Setpoints (section 4OA3.2)
50-321,366/02-05-03	NCV	Inadequate Assessment of Main Steam Safety Relief Valve (Section 4OA5.1)

Closed

50-321, 366/02-04-01	URI	Potential Inoperability of Main Steam Safety Relief Valves (Section 4OA5.1)

50-321/2002-002	LER	Technical Specification Required Plant Shutdown Because of High Unidentified Reactor Coolant System Leakage (section 4OA3.4)
50-321/2002-004	LER	Turbine Overspeed Control Valve of the High Pressure Coolant Injection System Fails (Section 4OA3.1)
50-321/2002-003	LER	Calculation Error Results in Incorrect Steam Line High Flow Setpoints (Section 4OA3.2)
50-321/2002-005	LER	Water Level Transient Following Manual Reactor Scram Causes Group 2 PCIS Isolation (Section 4OA3.3)

LIST OF DOCUMENTS REVIEWED

Section 1R02 and 1R17

Evaluations
DCR 99-035, Control Rod Drive Minimum Flow Bypass, Transmittal 99-035-003
TM 2-01-02, Removal of 3 Wires from Recirc Pump A Loose Parts Monitoring Alarm, MGR-0020, Rev. 5
SDC-00-6003, Jacket Cooling Pump Setpoint Change, ENG-0900, Rev. 1
Procedure 42SP-102501-OR-1-0S, SPP Uses Test Switches to Exercise HGA Relays in EDG, Rev. 1
DCR 98-46, Replace RMS-9 Trip Units with MVT(+) in 600 V Non-safety Switchgear, Rev. 0
DCR 00-007, Residual Heat Removal Service Water (RHRSW) Cutter Pumps, Transmittal 00-007-1-005
DCR 00-033, Upgrade Traveling Water Screens, Transmittal 00-033-001
LDCR 01-04, RHRSW Pipe Seal Plate, Rev. 0

Screened Out Items
DCR 00-029, Reactor Recirculation Pump/Motor Refurbishment, Transmittal 99-029-002
DCR 01-032, High Pressure Coolant Injection Discharge Drain Valve Removal, Transmittal 01-032-001
DCR 01-040, Plant Service Water Isolation Valves, Transmittal 01-040-001
DCR 02-010T, Shroud Head Bolt Removal, Transmittal 02-010T-001
DCR 01-66, Installation of PSW Isolation Valves, Transmittal 01-066-022
DCR 01-44, Replace EC-1 Trip Units with MVT(+) in 600 V Non-safety Switchgear, Transmittal 00-044-001
DCR 01-011, Recirculation Run Back on Low Level, Transmittal 01-011-004
DCR 01-031, RCIC Minimum Flow Test Valve Removal, Transmittal 01-031-002

DCR 01-045, RHRSW Motor Oil Coolers Flush Valves, Transmittal 01-045-001
DCR 02-028, Main Steam Line High Flow Setpoint, Transmittal 02-028-002
DCR 99-14, Removal / Replacement of UAT 1B, Transmittal 99-014-007
DCR 98-028, Unit 1 Nitrogen Storage Tank, Transmittal 98-028-002
Equivalency Determination (ED) 02-9092, SGTS Switch Replacement
ED 02-9051, Drywell Pneumatics Globe Valve Replacement, Rev. 0
ED 02-9044, Control Rod Drive Valve Subcomponent Replacement, Rev. 0

Self Assessment Documents
Report No. 2001-50.59, Audit Report of 10CFR50.59 Implementation
Audit No. 01-Outage-1, Audit of Unit 2 Outage Activities
CR 2001008697, Inappropriate use of Equivalency Determination Process
CR 2001008746, Documentation Errors in Minor Design Change Package
CR 2001009489, DCR had Wrong Designation on the Generator and Alternator Bearings
CR 2001010873, Commercial Grade Transformer used in EQ Application
CR 2001010998, Incomplete Evaluation of a Temporary Modification for Effect on the Diesel Generator
CR 2002001399, DCR did not Provide Tolerances for Calibration of New Radwaste Controllers
CR 2002003084, Unit 1 Hotwell not Constructed in accordance with FSAR
CR 2002003826, Failure to Update Procedure after SPDS Upgrade
CR 2002006590, DCR Failed to Provide Means of Checking Radwaste Timers
CR 2002009573, Failure to Perform Risk Assessment for Temporary Modification
CR 2002010017, Refueling Bridge Drawings not Updated after Modification
CR 2002010030, Design Documents not Updated after Modification to RHRSW Valves
CR 2002010031, Design Documents not Updated for RHRSW Pump Curves

Section 1R04
34SO-E41-001-1, High Pressure Coolant Injection (HPCI) System
34SO-R43-001-1, Diesel Generator Standby AC System
34SO-R43-001-2, Diesel Generator Standby AC System
34SO-E11-010-2, Residual Heat Removal System
34SO-P41-001-2, Plant Service Water System
34SV-E41-002-1S, HPCI Pump Operability
Plant Drawing H-16332, H-16333, H-11640, H-21039
MWO's 10202813, 10202830

Section 1R06
Instruments - Location & Mounting of Turbine Building Flooding Switches
H-11036, P&ID, Circulating Water System
H-13557, Elementary Diagram, Circulating Water and Condenser, Equipment and Auxiliaries
H-13610, Elementary Diagram, Misc. Pumps, Valves, & Equipment
H-13473, Wiring Diagram, 4160 V. SWGR, Bus 1A, FR3, R22-S001
H-11288, Instruments FCD, Circulating Water Pumps
H-21026, Turbine Bldg., Circulating Water System P. &I. D.
H-23684, Circulating Water and Condenser, Equip. & Auxiliaries Sys. 2N71& 2W23, Elementary Diagram
H-23685, Circulating Water and Condenser, Equip. & Auxiliaries Sys. 2N71, Elementary Diagram
H-23695, Plant Service Water - M.O. Valves - System 2P41, Elementary Diagram

H-23696, Plant Service Water - M.O. Valves - System 2P41, Elementary Diagram
A-44225, Flooding Criteria, Units 1 and 2
Unit 1 UFSAR, Section 11.6, Circulating Water System
Unit 2, UFSAR, Section 10.4.5, Circulating Water System
Procedure 57CP-CAL-061-1S, Robert Shaw Levelac Calibration
CR's 1995001406, 1995003432, 1995003434, 1995005397, 1995005516, 1996000224, 1996004925, 1997000536,1997004906, 1999000137, 2000002165, 2000004377

Section 1R12
MWO's 10002755, 10003872, 10101084, 10100286, 10200768, 10202984, 10203026, 10203119, 20103191, 20203598
Condition Reports 1998002977, 2002001668, 2002004963, 2002011317
10AC-MGR-021-0S, Foreign Material Exclusion
52PM-R43-015-0, Diesel Generator Turbocharger And Heat Exchanger Inspection
System Health Report for System R43, EDG's
Design Change Request 1H98-017, Commercial Grade O2 Analyzer
Plant Drawing H-26049-8 Sheet 1, H-26049 Sheet 2, H-28135

Procedures
40AC-ENG-020-0, Rev 4, Maintenance Rule (10 CFR 50.65) Implementation and Compliance
Southern Nuclear Company Structural Monitoring Program for the Maintenance Rule, Rev 6
Hatch Maintenance Rule Scoping Manual, Rev 4

Condition Reports (CRs)
CR 2001011086, Unit 1 RCIC loose terminals
CR 2001011090, Unit 1 RCIC failed to obtain proper flow and pressure in appropriate time
CRs 2002006730, 2002006731, 2002006732, 2002006733, 2002006735, 2002006736, 2002006737, 2002006738, 2002006740, 2002006741, 2002006742, 2002006738, Recommendations identified during Hatch MR Periodic Assessment, June 27, 2002
CR 2002008245, Unit 1 HPCI oil leak

Other Documents
Hatch MR Periodic Assessment, June 27, 2002
Hatch Monthly Site MR Summary Reports, May 2001 to September 2002
RHR Service Water Quarterly System Health Reports, April 2001 to September 2002
HPCI Quarterly System Health Reports, April 2001 to September 2002
Station Auxiliary AC Power Systems Quarterly System Health Reports, April 2001 to September 2002
RCIC Quarterly System Health Reports, April 2001 to September 2002
Station Auxiliary AC Power System Engineer MR Monthly Report, September 2002
RHR Service Water System Engineer MR Monthly Report, September 2002

Section 1R19
Condition Reports 2002010299, 2002010303, 2002010321, 2002010323