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

Report Nos.: 50-321/96-04 and 50-366/96-04

Licensee: Georgia Power Company
P.O. Box 1295
Birmingham, AL 35201

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

Facility Name: Hatch 1 and 2

Inspection Conducted: February 18, 1996 - March 30, 1996

Inspectors: For R. W. Wright 4/24/96
Bob L. Holbrook, Sr. Resident Inspector Date Signed

For R. W. Wright 4/24/96
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Accompanying Inspector: James A. Canady

Approved by: Pierce H. Skinner 4/25/96
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Project Branch 2
Division of Reactor Projects

SUMMARY

Scope: Inspections were conducted by resident inspectors and regional inspectors in the areas of plant operations which included; normal operations and testing, Unit one shutdown for a limited condition for operations, missed Technical Specification surveillance, Unit two shutdown and startup, self assessment, seismic instrument review, Unit one scram during shutdown activities, standby liquid control tank level problem, equipment tagging, refueling activities, and inspection of open items; maintenance which included routine maintenance and testing, excess flow check valve testing, containment penetration testing, foreign material exclusion review, and inspection of open items; engineering which included, integrated leak rate testing, design change request review, reactor feedwater pump turbine inspection, reactor core isolation cooling testing, design change request installation and testing, battery testing, and emergency diesel generator heavy load pathway review; and plant support which included; routine health physics and security activities, refueling support, new employee indoctrination activities, and a refueling floor airborne

problem. The inspectors conducted back shift inspections on the following dates: February 23, 26, 29, March 9, 11, 13, 14, 21-28, and 30, 1996.

Results: Three violations were identified.

Plant Operations:

The inspectors concluded that an experienced operating crew properly diagnosed problems with the 2B Steam Jet Air Ejector. The differences in the operating characteristics between the A and B train probably caused many of the previous Steam Jet Air Ejector problems. The differences had not been previously identified or evaluated by engineering or operations during similar problems with the system (paragraph 2.2).

The inspectors identified a strength in operator performance for a rapidly decreasing condenser vacuum. Operators' immediate response to rapidly decreasing reactor power probably prevented a turbine trip and reactor scram (paragraph 2.2).

The inspectors concluded that the clearance and tagging methodology was conducted in accordance with applicable procedures and the process was well-controlled (paragraph 2.3).

The inspectors concluded that the overall diagnostic skills for problem identification and resolution for the Standby Liquid Control tank level problem could be improved. The inspectors viewed the Department Directive outlining methods to improve troubleshooting abilities as a strength (paragraph 2.4).

The inspectors reviewed actions following a relay problem and subsequent shutdown Limited Condition of Operations for Unit 1 on March 9. The inspectors concluded that the notifications to the Nuclear Regulatory Commission were accurate. Attention to detail, heightened awareness to plant conditions, supervisory oversight, communications, procedure usage and teamwork on behalf of operations and maintenance personnel were very good (paragraph 2.5).

Violation 50-321/96-04-01: Failure to Complete Technical Specification Surveillance Procedure for Secondary Containment Integrity was documented. The inspectors identified a weakness in the surveillance program with respect to conditional or special surveillances (paragraph 2.6).

The inspectors concluded that initiating a unit shutdown to repair a leaking safety relief valve demonstrated a very good safety perspective. Participation from both on and offsite engineering was very good. Operations and maintenance performance during the unit shutdown and repair activities was also very good (paragraph 2.7).

The inspectors concluded that the overall self assessment review and response for reactivity control problems were satisfactory. A lack of recent errors indicated that licensee corrective actions were somewhat effective. Although the completed recommendations appeared to have been appropriately prioritized, a more aggressive approach for implementing the recommendations could have presented operators with a clearer understanding of management's expectations (paragraph 2.8).

The inspectors concluded that minor differences existed between the Final Safety Analysis Report recommended actions to be taken after a seismic event and the plant procedures. The licensee was reviewing procedures for possible improvements. The inspectors concluded that the seismic instrumentation was being maintained in accordance with the Technical Requirements Manual (paragraph 2.9).

The inspectors concluded that a more thorough review of the consequences surrounding increased reactor dome pressure, especially at reduced reactor power levels, could have possibly prevented the Unit 1 reactor scram on March 23, 1996 (paragraph 2.10).

The inspectors concluded that support by security, operations, maintenance, health physics, and engineering personnel during new fuel receipt was satisfactory. Operators demonstrated good attention to detail and awareness following the automatic reactor scram that occurred on March 23. Management attention to reactivity control activities and operator attention to detail resulted in very good performance during the fuel offload activities. No errors were identified (paragraph 2.11).

The inspectors concluded that the wording in the Final Safety Analysis Report Document Change Request, dated March 14, accurately described the licensees refueling and fuel pool cooling methodology (paragraph 2.11).

An example of Violation 50-321,366/96-04-02: Failure to Follow Procedure - Multiple Examples were identified. Unit two operations occurred for about four hours outside the region of operation defined on the Rated Thermal Power Versus Core Flow Map (paragraph 2.12).

Maintenance:

The maintenance activities observed were performed in a professional manner. The reactor building was well- maintained. However, the rest of the plant did not meet the same standard (paragraphs 3.0.1-3.0.4, and 3.1.1-3.1.4).

One example of Violation 50-321,366/96-04-02: Failure to Follow Procedure - Multiple Examples, was identified. On two separate

occasions the NRC inspectors discovered clear plastic on the refueling floor (paragraph 3.2).

The inspectors identified a weakness in some aspects of the foreign material exclusion program. The inspectors concluded that management's expectations for foreign material exclusion were not clear to all personnel. Initially management was responsive to specific problems that were identified. Management later broadened their scope of attention and provided more detailed corrective actions (paragraph 3.2).

Engineering:

The inspectors reviewed the integrated leak rate test final report for Unit 2, dated January, 1996. The inspectors concluded that the final report verified that the Unit 2 containment was successfully tested and the results were within the acceptance criteria (paragraph 4.1).

The inspectors reviewed the post modification performance of Unit 2 residual heat removal valves 2E11-F028A and B, torus cooling and spray isolation. Both valves were extensively modified during the Unit 2 fall 1995 refueling outage. The inspectors concluded that the valves were satisfactorily performing their intended function (paragraph 4.2).

The inspectors reviewed licensee actions in response to Technical Information Letter 1129-3: Potential Rotor Cracking in Shaft Keyways For Mechanical Driven Steam Turbines With Shrunk-on Couplings. Licensee actions were satisfactory. Inspections were completed on Unit 2 and deficiencies were not identified (paragraph 4.3).

Violation 50-321/96-04-03: Inadequate Procedure For Operating Reactor Core Isolation Cooling system from The Remote Shutdown Panel, was identified. Plant procedures did not contain all the required instructions to place the system in operation (paragraph 4.4).

The inspectors observed and reviewed the post modification operation of the Unit 2 high pressure coolant injection and reactor core isolation cooling systems following the November refueling outage. The inspectors concluded that system operation was satisfactory. Performance during surveillance operations did not identify any discrepancies (paragraph 4.6).

Plant Support:

The inspectors concluded that, except for some minor deficiencies dealing with tools, equipment and clothing lying across some radiological control boundaries, health physics support and contamination control for refueling preparations were good.

Health physics controls and support for drywell work activities were good (paragraph 5.1).

The inspectors concluded that the new initiative for new contractor indoctrination and plant tour demonstrated managements serious concern for improvement in the Health Physics and contractor performance area (paragraph 5.2).

The inspectors concluded the licensee conducted an adequate analysis to characterize the root cause of the airborne radioactivity event that occurred on March 28, and conducted adequate surveys to address any potential radiological consequences associated with the airborne event (paragraph 5.3).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 9.

1.0 Persons Contacted

Licensee Employees

*Anderson J., Unit Superintendent
Breitenbach K., Engineering Supervisor
Bennett D., Chemistry Superintendent
Beck J., Team Leader, Shift Team "A"
Betsill J., Operations Manager
Brunson S., Nuclear Safety and Compliance
*Carroll A., Shift Support Supervisor
*Coggins C., Engineering Support Manager
Crowe D., Hatch Licensing Manager, Southern Nuclear
*Curtis S., Operations Support Superintendent
Davis D., Plant Administration Manager
*Durrence A., Plant Equipment Operator
*Elder D., Training Supervisor
*Fornel P., Performance Team Manager
*Fraser O., Safety Audit and Engineering Review Supervisor
Gibson E., Reactor Engineering Supervisor
Godby R., Maintenance Superintendent
*Googe M., Modifications and Maintenance Support Manager
*Hayes V., Operations
*Kirkley W., Health Physics and Chemistry Manager
Lewis J., Training and Emergency Preparedness Manager
Link M., Supervisor, Health Physics
*McDaniel C., Acting Plant Administration Manager
McGinn R., Security Operations Supervisor
*Metzler T., Acting Manager Nuclear Safety and Compliance
*Moore C., Assistant General Manager - Plant Support
Page C., Assistant Team Leader, Maintenance
*Payne J., Senior Engineer
Pooni R., System Engineer
Riner G., Plant Health Physics and Chemistry
Roberts P., Outages and Planning Manager
Robertson J., Acting Manager, Modifications and Maintenance Support
Smith D., Superintendent, Chemistry
Sumner H., General Manager - Nuclear Plant
*Thompson J., Nuclear Security Manager
Tipps S., Nuclear Safety and Compliance Manager
*Tootle D., Shift Technical Advisor
*Wells P., Assistant General Manager - Operations

Other licensee employees contacted included office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

2.0 PLANT OPERATIONS (71707) (40500) (60705) (92901) (60710)

Activities within the control room were routinely monitored. Observations included control room manning, access control, operator professionalism and attentiveness, and adherence to procedures. Instrument readings, recorder traces, annunciator alarms, operability of nuclear instrumentation and reactor protection system channels, availability of power sources, and operability of the SPDS were monitored. Control Room observations also included ECCS system lineups, containment and secondary containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls.

Observed activities were conducted as required by the licensee's procedures. The complement of licensed personnel on each shift met or exceeded the minimum required by TS. Observed operating parameters were verified to be within TS limits.

2.1 Plant Status

Unit 1 began the report period at 93% RTP during end of core life coastdown. Reactor power was decreased to about 77% RTP on March 9, to comply with TS 3.0.3 actions for a shutdown LCO. A bad relay coil and blown fuse resulted in the loss of all RCS leak detection systems. The problem was repaired and reactor power was returned to maximum RTP the same day. Power was reduced to about 60% RTP on March 16, to remove the 1B CCW and 1A RFPT from service to begin pre-outage maintenance activities. On March 23, the unit automatically scrammed from 17% RTP when the main turbine was removed from service. A procedural deficiency resulted in a reactor scram on high reactor pressure. The main turbine bypass valves opened as expected then reclosed. The unit began the 16th refueling outage. The unit was in the refueling outage for the remainder of the report period.

Unit 2 began the report period at 100% RTP. On February 23, power was reduced to about 60% RTP to perform a control rod sequence exchange and conduct maintenance on the A RFPT seals. 100% RTP was attained on February 25. On February 27, power was reduced to about 85% RTP to repair a steam leak on the A SJAE. The A SJAE was left in service due to a steam leak on the B SJAE. Unit power was increased to 100% the same day. Power was subsequently reduced to 85% RTP to place the B SJAE in service following repairs. Later the same day power was reduced to about 20% RTP due to decreasing condenser vacuum. Power was stabilized at about 62% RTP and the A SJAE was placed back in service. The unit reached 100 % RTP on February 29. The unit was shutdown on March 12, to replace the H SRV and conduct repairs on the D SRV. The reactor was brought critical and 100% RTP was achieved on March 18. The unit operated at 100% RTP for the remainder of report period with the exception of scheduled power reductions for routine testing.

2.2 Unit 2 SJAE Problem

On February 23, reactor power was reduced to conduct routine testing and maintenance activities. During the increase in power on the 24th a steam leak was identified in the 2A SJAE room. It was later determined that the Y strainer on the steam supply line for the inservice SJAE was leaking. Operations personnel determined that immediate operation of the SJAE was not affected. On the 26th, KOPPLE, a contractor that repairs active leaks with liquid sealants, evaluated the problem and determined the leak could not be sealed. Power was increased to 100% RTP.

On the 27th, operators reduced power to approximately 85% RTP in preparation to swap to the B SJAE. When the B SJAE was placed in service a leak was also observed on a strainer. The A SJAE was left in service so maintenance could perform welding repairs on the B.

Following the weld repairs, the B SJAE was placed in service and maintenance was initiated on the A SJAE on the 28th. Following the initial maintenance activities welding was required a second time to correct the problem. After B had been in service for about 6 hours operators observed that condenser vacuum was decreasing. Operators reduced power to approximately 20% RTP in an effort to stop the decreasing vacuum. Condenser vacuum decreased to approximately 23 inches Hg before improvements were observed. An automatic turbine trip and subsequent reactor scram would occur at 22.3 inches Hg. The A SJAE was placed in service and power was increased to 100% RTP on the 29th.

A problem identified during this activity included the following: Valve 2N22F147A, the 8th stage heater high level dump valve failed to open. Maintenance personnel had repaired the valve about 3 hours after the problem was identified.

Later when reactor power was reduced to improve vacuum, the 7th and 8th stage FW heaters isolated on high level. In this case the high level dump valves worked properly. The inspectors did not view the heater isolations as a problem with respect to reactor thermal limit concerns. The inspectors concluded that heater string isolations were to be expected at the reduced power level.

Valve, 2N11F001B, main steam supply to SJAE B, would not open. This valve was later manually opened locally. An outstanding MWO was initiated to repair the valve at the next opportunity.

The condenser vacuum problem was reviewed by operations and maintenance personnel. Physical problems with the SJAE were not identified. Operations and engineering personnel concluded that the main steam pressures to the SJAE should be increased from about 360 psig to about 500 psig, if necessary, to improve performance. A temporary change to procedure 34SO-N61-001-2S:

Main Condenser Vacuum System and Closeout, was implemented to increase the operating pressure.

The inspectors were aware of previous problems with placing the B SJAE in service. Additionally, plant scrams had previously occurred while attempting to place the standby SJAE in service. The B SJAE was used very little during the last 8 to 10 years. Only recently, within the last two years, were significant corrective actions completed for system improvement. The inspectors discussed the above problems with licensee management. The inspectors were informed that the leak on the B SJAE was believed to have been caused by a previous maintenance welding activity that occurred in October 1995. Welding on the Y strainer had damaged the strainer nipple. The inspectors concluded this type of damage would be difficult to determine unless the system was pressurized following maintenance. The SJAE was not placed in service following maintenance activities during the last refueling outage.

The inspectors also concluded that the onshift operating crew properly diagnosed some of the problems with the B SJAE and made recommendations for improvements. The inspectors observed that the operating procedure was written for both the A and B SJAE. However, the actual required operating parameters were different for the two trains. The B SJAE would not operate properly as the procedure was written. During this problem the operating crew identified that the main steam inlet pressure for the B SJAE was required to be considerably higher than that for the A train. The inspectors concluded that the difference in operating characteristics probable caused many of the previous SJAE problems. However, the difference in the required SJAE inlet steam pressure and other problems had not been previously identified or evaluated by engineering or operations. There were less problems placing the A SJAE in service and the B was seldom used.

The inspectors discussed the availability and operational condition of the B SJAE with operations and engineering personnel. The inspectors were informed that the system had been used very little in several years. Plant personnel lacked confidence in their ability to place the system in service. Additionally, they were not confident that the system would remain in service and perform it's function. The inspectors concluded the operational condition of the standby SJAE presented little safety significance for continued plant operation. However, the inability to transfer to the standby train if required could result in a more significant plant transient or scram. IR 50-321,366/95-06, documented a similar problem of a lack of attention to standby equipment (PASS).

The inspectors identified a strength in operator performance for a rapidly decreasing condenser vacuum. Operator immediate response

to rapidly decrease reactor power probably prevented a turbine trip and reactor scram. The inspectors concluded that management did not provide adequate attention to the operational condition of the standby SJAE. The licensee was aware of the difficulties in operating the B SJAE for over 10 years. However, long standing problems were not diagnosed, evaluated, or corrected to ensure a standby train of SJAE was available and in good working condition. The inspectors reviewed FSAR section 10.4.2 with respect to the SJAE and did not identify any discrepancies.

2.3 Review of Equipment Clearances and Tags

The inspectors reviewed the licensee's activities associated with the control of equipment clearances and tags. The inspectors reviewed procedure 30AC-OPS-001-0S: Control of Equipment Clearances and Tags, Revision 14, to verify activities were conducted in accordance with procedural requirements. The inspectors conducted a detailed review of clearance 1-95-57. The clearance tagged portions of the fire protection header to support new cooling tower installation and other maintenance activities. The inspectors independently verified valve positions and tagging documentation of selected valves. No discrepancies were identified.

The inspectors concluded that the clearance and tagging methodology was conducted in accordance with applicable procedures and the process was well controlled.

2.4 Unit 1 Standby Liquid Control Problem

The inspectors conducted a review of activities associated with a SBLC tank level problem that was ongoing between February 12 and 16, 1996. A Unit 1 main control room alarm indicated that the SBLC tank level had increased. Operations personnel investigated the problem and suspected a normally closed demineralized water make-up valve was leaking by. Operators retightened the closed suspected valve. They also suspected a second isolation valve was leaking by when the tank level appeared to continue to increase. On two occasions operations personnel reduced the tank volume in an attempt to restore normal level.

The shift performance team was requested to assist with the problem. I&C personnel were requested to calibrate the tank level gauge. I&C completed procedure 57CP-CAL-137-0S: Pressure Gauges, Revision 0, ED 2, and concluded the tank level guage was properly calibrated. The tank level indicated 3300 gallons. Chemistry personnel conducted several concentration samples and reported to operations that the concentration was within specifications for the indicated level.

Maintenance personnel cut the piping and removed one of the suspected leaking valves. While the demineralized water makeup

valve was removed from the line the SBLC tank level appeared to increase. At this time operations personnel realized that a leaking valve was not the problem and the tank level was not actually increasing.

Personnel then realized that the tank level indicator system was not operating properly. They suspected that the level bubbler system was partially plugged resulting in higher than actual tank level indications. Repairs were initiated. The air bubbler system line was cleared. I&C supervision stated they suspected that sodium pentaborate had plated out in the tank level instrument bubbler line. I&C personnel indicated a similar problem had occurred several years ago.

The inspectors discussed with licensee management the number of activities that were completed before the problems' actual cause was identified. The inspectors also discussed the trouble shooting techniques and diagnostics skills used to investigate the problem and whether or not activities were timely. For example, several chemistry sample analysis for concentration did not support the observations that the tank level had increased. Although several samples were taken no one viewed or measured actual tank level. The tank level calibration procedure completed by I&C did not detect tank level instrumentation deficiencies. Operations personnel twice decreased the SBLC tank level. Only after maintenance personnel cut and removed a makeup water valve was it evident that the tank level was not actually increasing. These activities occurred over a five day period.

The licensee initiated a SOR. As part of their investigation they viewed the inside of both Unit 1 and Unit 2 SBLC storage tanks. They discovered 8 or 10 small pieces of thin clear plastic strips in the Unit 1 tank. The plastic may have been introduced into the storage tank when sodium pentaborate was added to the storage tank. Licensee management stated a review of the sodium pentaborate addition process would be reviewed for possible improvement. The inspectors agreed with the licensees' conclusion; which was, since the bubbler system maintains a continuous air flow through the level sensing line the plastic did not contribute to the level indication problem. The inspectors also concluded that the small amount of plastic probably would not have degraded pump or system operation. However, there appeared to be a lack of attention to detail for FME controls. See paragraph 3.2 for additional discussion of FME problems.

Following the licensee investigation a plant wide Department Directive was issued. The directive presented a time line of events and actions completed during the troubleshooting. The directive also discussed techniques to improve troubleshooting abilities.

The inspectors reviewed procedure 57CP-CAL-137-OS: Pressure Gauges, Revision 0, ED 2, used to calibrate the tank level instrument. The inspectors observed that the procedure verified that the level instrument responded properly to the sensed bubbler back pressure. However, there were no procedure to verify the bubbler system sensing line was operating properly. Additionally, there were no procedure or condition that required a visual check of the tank level to confirm proper instrument operation. Licensee management stated that the need for such checks was under evaluation.

As part of the licensee's investigation, the Unit 2 SBLC system was reviewed. The licensee determined that Unit 2 SBLC tank level indicated approximately 300 gallons more than actual level. The level instrumentation was corrected to reflect the actual level.

The inspectors reviewed Unit 1 and Unit 2 TS and verified that the lowest identified SBLC tank level and concentration were within the TS "permissible region of continuous operation" and met all TS requirements. The inspectors also reviewed Unit 1 and Unit 2 FSAR sections 3.8 and 4.2.3.4.3. The inspectors observed that the TS figures depicting system concentration and volume were slightly different from the FSAR figures for concentration and volume requirements. However, the TS graphs were more conservative in all respects than the FSAR figures and no additional documentation is required in this report.

The inspectors concluded that the licensees actions corrected the problem but could have been more timely. The ongoing review and evaluation of the tank level instrument calibration procedure for possible enhancements were appropriate. The inspectors also concluded that the overall diagnostic skills for problem identification and resolution could be improved. The inspectors viewed the Department Directive outlining how to improve trouble shooting abilities as a positive step. It was fortuitus that the SBLC tank level was not drained down to a level that required the system to be declared inoperable.

2.5 Review of Unit 2 Group 2 Isolation and TS Shutdown LCO

The inspectors reviewed licensee actions in response to a "smell of smoke" in the main control room at about 1:30 p.m., on March 9. The smell was determined to be coming from the PCIS Outboard Isolation panel. During the investigation a Group 2 Outboard isolation occurred. Licensee personnel discovered a fuse failure caused the isolation. They also discovered that a bad coil in a CR 120 relay was the cause of the problem.

As a result of the group isolation, all of the RCA leak detection systems were declared inoperable and TS 3.0.3 was entered. The unit was required to be in Mode 2 within 7 hours. The licensee decreased power to about 77% RTP in preparation for the unit

shutdown. Maintenance personnel electrically isolated the bad relay, replaced the blown fuse and operations reset the Group 2 isolation. The unit power decrease was terminated and power was returned to maximum rated power at about 6:35 p.m. the same day.

The inspectors observed operations and maintenance activities through the majority of the trouble shooting and repair activities. The inspectors verified the TS actions taken were correct. The inspectors also reviewed the 10 CFR 50.72 notification for the ESF actuation and the notification for plant shutdown required by TS. The inspectors concluded the notifications were accurate. The inspectors reviewed the DC and MWO generated for the problem. The inspectors concluded the administrative documentation surrounding the problem was clear and concise.

The inspectors reviewed procedure 53PM-MON-003-0S: Infrared Thermography Program, Revision 2, and determined that the failed relay was included in the program and had been surveyed in January 1996. The survey indicated the relay temperature was 165° F. This was well below the 194° F limit which is used to identify when the relay should be replaced. Three previous survey readings since June 1994, did not indicate an increased temperature. The inspectors concluded that, even though the Infrared Thermography Survey program did not indicate a increased relay temperature problem, the relay had been surveyed at a reasonable frequency.

The inspectors also concluded that the attention to detail and heightened awareness to plant conditions by operations and maintenance personnel were very good. Supervisory oversight, communications, procedure usage and teamwork of the work groups were very good. The inspectors reviewed FSAR sections 6.2 and 7.3 for containment isolation and did not identify any inconsistencies with plant practices and procedures.

2.6 Missed Secondary Containment Integrity TS Surveillance

On February 23, the inspectors were informed that a routine Unit 1 TS surveillance was not completed within the required frequency. TS surveillance requirement 3.6.4.1.1 and 3.6.4.1.2, requires in part, that all secondary containment equipment hatches be closed and sealed and access doors closed except when used for entry or exit and then at least one door shall be closed. These checks were required at a frequency every 31 days.

The inspectors reviewed procedure 34SV-T22-002-0S: Secondary Containment Integrity Demonstration, Revision 1. The procedure was successfully completed on February 23, 1996, and no deficiencies were identified. The extended grace period to satisfactorily meet the required frequency expired on February 5, 1996. The inspectors reviewed plant conditions between February 5 through February 23 and did not identify any conditions that

presented a secondary containment integrity concern. The inspectors discussed the missed surveillance with licensee management and operations personnel.

Operations personnel used surveillance task sheets, which indicate the TS requirement, procedure number and title, work instructions, procedure late date and other pertinent information to determine when and what surveillances should be completed. In this instance the SSS misread the task sheet work instructions and determined the surveillance was not applicable for the present plant condition. The procedure number was also misread. After reviewing an incorrect procedure for applicability, the SSS decided to defer performing the surveillance procedure.

The inspectors reviewed the task sheet and concluded that sufficient information was available to determine the surveillance was applicable to the plant condition. The task sheet indicated "APPL MODE: 1234N" the task sheet also indicated "WORK INSTRUCTION: MODE 1,2, & 3, DURING MOVEMENT OF IRRADIATED FUEL ASSEMBLIES IN THE SECONDARY CONTAINMENT, DURING CORE ALTERATIONS ...". The inspectors reviewed TS 3.6.4.1 and concluded the TS clearly identified the SV was applicable for the current operating mode. The inspectors were informed that the SSS did not review TS to verify whether or not the SV was applicable. The TS surveillance review program did not require a second review or concurrence for deferred surveillances. Therefore, in this case, the SSS did not seek concurrence from crew members or supervision prior to deferring the SV.

The inspectors concluded that the cause of this missed surveillance was personnel error. This problem was discussed with licensee management. The inspectors were informed that the SV process was under review and would be revised to require the STA or SOS to review surveillances prior to their deferral. The inspectors were also informed that the individual involved in this problem was entered in the positive discipline program.

The inspectors reviewed licensee performance for the past two years with respect to missed surveillances. IR 50-321/366-94-11, 94-28, and 95-08, documented problems with completion of TS surveillances. At least five LERs associated with deficiencies that resulted in missed surveillances were documented. The inspectors concluded that many of the missed surveillance procedures involved different circumstances such as deferred or conditional surveillances and personnel error. The inspectors observed that the individual missed surveillances presented little safety significance for plant operation. However, the licensees corrective actions to ensure required TS surveillances were completed were not thorough and comprehensive for all circumstances. Corrective actions for previous instances of missed surveillances (as identified in LERs and NCVs), would reasonably have been expected to have prevented this violation.

Given the instances of missed TS surveillance tests it was reasonable to have expected the licensee to have implemented necessary corrective actions to strengthen the TS surveillance program.

Review of the Enforcement Policy Manual determined that all NCV criteria were not met for this late surveillance; hence, the failure to complete the Secondary Containment Integrity Demonstration TS surveillance as required was identified as VIO 50-321/96-04-01: Failure to Complete Technical Specification Surveillance Procedure for Secondary Containment Integrity.

This violation is applicable to Unit 1 only.

2.7 Unit 2 Shutdown to Replace Leaking SRV

A new H SRV was installed during the last Unit 2 refueling outage in November 1995. After startup the tailpipe temperature indicated approximately 208°F. By about March 3, the tail pipe temperature had risen to about 273°F.

During this period the inspectors observed and routinely monitored the SRV tailpipe temperatures. IR 50-321,366/95-23 and IR 94-15 documented inspector observations of SRV leakage. The inspectors concluded that operations and engineering personnel were taking prudent actions in response to this and the previous increased temperature indications.

A PRB meeting was held on March 6, to discuss a Temporary Modification to increase the alarm setpoint of the H SRV. The tailpipe temperature had increased to a point that the alarm was in continuously. This condition would prevent other leaking SRV tailpipe temperature increases from alarming in the main control room. The inspectors attended the PRB meeting, reviewed the 10 CFR 50.59 review and observed PRB member activities. The inspectors concluded PRB members demonstrated a questioning attitude and focused on plant safety. The inspectors observed that the alarm setpoint change was approved.

The licensee discussed the problem with NRC management in a conference call on March 1. During the discussion the licensee indicated they suspected leakage through the pilot valve and not the main valve seat. The licensee observed that the tail pipe temperature increased about 12 °F during recent power changes following SJAE maintenance activities. During the conference call licensee management, onsite and offsite engineering and operations management were aware of the potential problems associated with leaking SRV's.

The licensee utilizes Target Rock Two-Stage Pilot Actuated Safety Relief Valves and was aware of recent problems with these valves at another site. The licensee discussed their assessment of the

leaking SRV problem and actions to monitor the SRV tailpipe temperatures, suppression pool heatup and suppression pool volume increase. The licensee also discussed their leakage rate determination and criteria they would use for initiating a reactor shutdown to repair the leaking SRV.

Even though the preestablished criteria to initiate a unit shutdown was not met, management decided to shut down Unit 2 on March 12, and initiate repairs. The inspectors concluded this decision demonstrated a very good safety perspective from licensee management. Participation from both on and offsite engineering to establish continued plant monitoring and unit shutdown criteria was very good. Operations and maintenance performance during the unit shutdown and repair activities was also very good.

The H SRV was removed from service, shipped offsite for inspection, testing and evaluation to determine why the valve began leaking. The inspectors reviewed an initial report from corporate engineering dated March 28, which indicated the H SRV tested satisfactorily and within the TS limits for opening. The report also indicated that steam cutting of the seat surface of the pilot disc had occurred. At the end of the report period the licensee was still evaluating available date to determine the root cause of the failure.

2.8 Licensee Self Assessment

The inspectors documented in IR 95-22 licensee performance for reactivity management control problems. The problems included personnel error during refueling operations and control rod movement errors. Four VIOs and three NCVs were issued due to continued poor performance in this area during the past two years.

Between January 26 and February 3, 1996, the licensee conducted a reactivity controls assessment. A seven person assessment team included personnel from plant Hatch, Southern Nuclear and external organizations. The focus of the assessment was to address improvements and corrective actions which would strengthen reactivity controls at Plant Hatch. The scope of the assessment addressed reactivity controls related to control rod movement and fuel bundle movement errors.

The inspectors reviewed the team's final report dated March 4, and operations management response to the final report recommendations dated March 25. The inspectors observed that the final report contained 17 specific recommendations. The inspectors reviewed the licensee's implementation of the recommendations with respect to the beginning of the current refueling outage that began on March 23. The inspectors observed that some recommendations were completed prior to the refueling outage. The completed recommendations appeared to have been appropriately prioritized. Others were deferred until after the outage. The inspectors

concluded that the deferred items were mostly administrative in nature, others applied to Unit 2 procedures. The inspectors observed that some of the deferred recommendations dealt with clarification and reinforcment of managements expectations for improved performance. Some recommendations were already part of the licensee's programs but apparently were not recognized by the assessment team. Operations management identified these items as needing strengthening.

The inspectors concluded the overall assessment review and response were satisfactory. The scope and evaluation of the problem appeared to be good. There were no errors during the last Unit 2 fuel movement or during the recent Unit 1 defueling activities. A lack of recent errors indicated that licensee corrective actions were effective.

2.9 Seismic Instrumentation Review

The inspectors reviewed and observed the status of the seismic instrumentation system. The inspectors reviewed the TRM Specifications, Section T 3.0. The TRM Specifications include Operational Requirements, Surveillances, and Required Actions for inoperable equipment. The review included the completed surveillances as required by TSRs 3.3.6.1, 3.3.6.2, and 3.3.6.3, Channel Check, Functional Test and Calibration. The observation included the accessible instrumentation. The inspectors noted that the accessible Peak Recording Accelerometers, which are located in areas such as the EDG building, intake building and the CR, were not labeled. This was not in accordance with the plant practice of labelling all instruments. This observation was discussed with the licensee. The inspectors reviewed deficiencies documented for the past two years and concluded the number was reasonable. The inspectors concluded that the seismic instrumentation was being maintained in accordance with the TRM.

As part of the seismic instrumentation review the inspectors reviewed plant procedures associated with licensee's operational response to an OBE. Two plant operating procedures discuss the expected operator responses to an OBE, 34AB-Y22-002-0S: Naturally Occurring Phenomena, Revision 1, and 73EP-EIP-001-02: Emergency Classification and Initial Actions, Revision 11. The latter procedure referenced a vendor document SX18271: Seismic Instrumentation Earthquake Response Manual, dated January 31, 1979, which was also reviewed. Two alarm response procedures 34AR-657-066-1S: Seismic Peak Shock Recorder High Level, and 34AR-657-067-1S: Seismic Instrumentation Triggered, direct the operators to perform specific actions. In conjunction with this activity the inspectors reviewed applicable sections of the Units 1 and 2 FSAR. The review indicated the following discrepancies:

- Unit 2 FSAR Figure 3.7A-7: Post-Seismic Event Plant Procedures, contains an outline of the order of actions to be

taken after a seismic event. Neither procedure 34AB-Y22-002-0S or 73EP-EIP-001-02 reference these step by step actions for implementation. However, the above alarm response procedures did reference this diagram.

- Unit 2 FSAR Figure 3.7A-7 differentiates between actions to take for an equal to or less than OBE event and a greater than OBE event. The plant operating procedures discuss the seismic event only in terms of equal to or greater than OBE.

- Unit 2 FSAR Figure 3.7A-7 indicated that following an earthquake the first activity to be performed was a seismic acceleration review. The plant operating procedures did not clearly direct that this be done.

- Unit 2 FSAR Figure 3.7A-7 indicated that safety systems would be inspected and tested following an earthquake that was greater than an OBE. The plant procedures did not clearly direct that this be done. The inspectors observed procedure 34AB-Y22-002-0S directed that the entire plant be inspected for damage.

- The inspectors observed that procedure 34AB-Y22-002-0S, implemented on November 31, 1995, contained a note referencing a Unit 2, SR 4.3.6.2.2. Due to the implementation of the TSIP in July, 1995, this SR no longer exists.

- The inspectors observed that vendor document SX18271 contained a diagram indicating steps to be followed in the event of an earthquake. The vendor diagram was different from the diagram contained within the FSAR. The inspectors also observed that the plant operating procedures did not contain expected operator action if a unit or both units were to scram as a result of a seismic event.

The inspectors concluded that operator actions and followup activities outlined in the FSAR were not clearly defined in plant operating procedures. The differences between the plant operating procedures, the FSAR diagram, and the vendor diagram were considered minor. The possibility that these differences could cause confusion on the part of the operators was considered minimal. These items were discussed with the licensee's operations management. Near the end of the inspection report the licensee informed the inspectors that they were still reviewing plant procedures for possible changes.

2.10 Unit 1 Automatic Reactor Scram During Shutdown Activities

On March 23, operations began reducing reactor power in preparations for the Unit 1 sixteenth refueling outage. Shutdown plans were to reduce reactor power to about 16% RTP, remove the main generator from the grid, conduct main turbine overspeed

testing, manually scram the reactor and continue reactor cooldown to begin the refueling outage. The main turbine was tripped in accordance with the procedure as planned. However, the reactor automatically scrammed. Operations later determined the reactor scrammed on high reactor pressure.

One of the inspectors proceeded to the site to review the occurrence and observe licensee activities. Operations personnel informed the inspectors they suspected the turbine bypass valves opened as designed following the turbine trip. However, they believed the bypass valves immediately closed resulting in a high reactor pressure scram. The inspector viewed the control room pressure recorder and observed that reactor pressure peaked between 1020 and 1025 psig. Operations personnel observed reactor pressure at the local panels indicated about 1040 psig. The inspectors verified the TS RPS scram signal for high reactor pressure was less than or equal to 1054 psig. The RPS scram signal occurred as required by TS.

The licensee initiated an ERT to investigate the problem and make recommendations for corrective actions. The inspectors discussed the scram with ERT members. The ERT discovered the cause of the scram was not a bypass valve problem. The reactor scrammed on high reactor pressure as required. It was determined that a reactor pressure spike of about 50 psig following a turbine trip was normal. In this case the pressure spike reached the RPS high pressure scram setpoint.

GE conducted several analysis in preparation for the power uprate program which was completed on Unit 2 and was implemented on Unit 1 during the current outage. Part of the analysis, which resulted in increased efficiency, was for increased reactor dome pressure. As a result plant procedures 34GO-OPS-005-1S/2S: Power Changes, were revised to allow increased reactor dome pressure to between 1003 and 1005 psig. During a normal shutdown the increased dome pressure does not present a problem. Dome pressure decreases as reactor power decreases. When the turbine was tripped the normal 50 psig spike would not reach the RPS high pressure setpoint.

In preparation for the Unit 1 refueling outage that began March 23, reactor power was reduced to about 58% RTP. To maintain efficiency the dome pressure was increased from the reduced pressure back up to 998 psig. The procedure directed that reactor pressure be maintained between 1003 and 1005 psig. Increasing reactor dome pressure reduced the margin normally available to accommodate the routine 50 psig spike following a turbine trip.

The inspectors reviewed revisions 15, 16, and 17 of the power change procedure. Revision 15 of the Unit 1 procedure contained a limitation that indicated it was not desirable to operate below 96% RTP at the increased dome pressure and if this condition occurred to initiate a DC. The procedure also directed for

planned power reductions below 96% RTP to decrease dome pressure below 990 psig. It was later determined this restriction was not applicable to Unit 1 until after power uprate was completed. Revision 15 of the Unit 1 procedure was temporarily changed and later revised to delete the limitation and the requirement to decrease dome pressure for power operations below 96% RTP.

As a result of the procedure revisions the operators were no longer directed to reduce reactor dome pressure and were directed to maintain reactor steam dome pressure between 1003 - 1005 psig. Increasing dome pressure at a reduced power level resulted in reaching the RPS high pressure scram setpoint when the main turbine was tripped. The inspectors observed that the procedure did not specifically address the consequences of increasing dome pressure with an already reduced reactor power. The inspectors observed that the problem also applied to Unit 2. Licensee management informed the inspectors that the procedures would be reviewed for possible corrective actions.

The inspectors did not identify any plant or GE reviews that addressed the possible consequences of increasing reactor dome pressure at a reduced reactor power.

The inspectors reviewed Unit 2 FSAR section 13.5.3, Normal Operating Procedures. The Power change procedure was listed as an normal operating procedure. However, no specific details or descriptions were available.

The inspectors concluded the ERT investigation was excellent. The inspectors concluded that a more thorough review of the consequences surrounding increased reactor dome pressure, especially at reduced reactor power levels, could have possibly prevented this scram.

2.11 Preparations for Refueling and General Refueling Activities

The inspectors reviewed and observed licensee activities associated with the preparations for refueling activities. The inspectors reviewed the refueling outage schedule including critical path items with planning and scheduling management. The inspectors also reviewed the Refueling Outage Shutdown Letter and Shutdown Risk Assessment. The inspectors observed that most operations personnel questioned were familiar with some of the information contained within the Shutdown Risk Assessment. Operations also began discussing this information in more detail at BOST sessions.

Among applicable procedures reviewed by the inspectors were the following:

- 42FH-ERP-012-OS: New Fuel and New Channel Handling, Revision 6
- 42FH-ERP-014-OS: Fuel Movement, Revision 11

- 34FH-OPS-001-0S: Fuel Movement Operations, Revision 12
- DI-OPS-37-0889N: Fuel Movement Rules, Revision 4
- Required Reading and Refueling Procedures Review For Refueling Personnel
- Abnormal and Emergency Operating Procedures associated with refueling activities

The inspectors observed licensee activities associated with new fuel receipt, transfer of new fuel to refueling floor and initial inspection. The inspectors concluded support by security, operations, maintenance, HP, and engineering personnel was satisfactory. Deficiencies were not identified during these activities.

The inspectors observed operator actions to continue unit shutdown and cooldown following the automatic reactor scram that occurred on March 23, 1996 (paragraph 2.11). The inspectors observed that plant procedures and TS were correctly used. Operations demonstrated good attention to detail and plant awareness. Shift supervision was actively involved with ongoing activities and operations management was present and provided oversite.

The inspectors rode the refueling bridge and observed fuel movement and fuel sipping activities. The inspectors observed that operators used a mast installed camera to verify the correct fuel bundle was grappled and a second verifier was also used to verify correct fuel bundle prior to fuel movement. The inspectors observed that operations management also rode the refueling bridge to observe portions of the fuel movement activities. The inspectors observed that fuel offload occurred with no refueling errors.

The inspectors concluded that management attention to reactivity control activities and operator attention to detail resulted in very good performance during the fuel offload activities.

The inspectors reviewed the adequacy of the original heat load design assumptions for the Spent Fuel Pool Systems relative to the current operating practice. The inspectors reviewed Unit 2 FSAR section 9.1.3 and Unit 1 FSAR section 10.4 for the Spent Fuel Pool Cooling and Cleanup System and applicable system operating procedures.

The inspectors concluded that the licensee's refueling methodology, with respect to heat load removal capability, was bound by the FSAR. However, what the FSAR described as the maximum heat load condition, was consistent with what the licensee does during a normal routine refueling outage. These differences are documented in IR 50-321,366/95-23 paragraph 4.e.

The inspectors reviewed licensee Document Change Request 96-05, and 10 CFR 50.59 review, dated March 14, 1996, that approved a

Unit 1 and Unit 2 FSAR change. The changes clarified the differences documented in the above IR. The change also clarified what a normal refueling strategy was with respect to how much of the core is off-loaded into the spent fuel pool during refueling outages. The change clarified that either a partial or a full core offload can be performed at Hatch and that neither one is necessarily the normal mode of operation for Hatch. The FSAR change will be submitted at the next scheduled update.

The inspectors concluded the wording in the FSAR Document Change Request accurately described the licensees refueling and fuel pool cooling methodology.

2.12 Unit 2 Operation Above the APRM Rod Block Line

Between February 27 and 29, Unit 2 decreased power to conduct maintenance on the SJAEs and subsequently increased reactor power toward 100% RTP. Control rods were withdrawn to near the APRM rod block line and the target control rod pattern was achieved at 0025 a.m. on February 29. Power was then increased toward 100% RTP using RR flow.

Reactor power reached about 99.78% RTP with about 83% core flow. The oncoming dayshift STA recognized that core flow for the present power level was not acceptable. A determination was made that operation was in an unanalyzed region of the rated thermal power/core flow map. Reactor engineering was contacted and they recommended control rods be inserted to reduce reactor power. RR flow was then increased to above the minimum acceptable flow.

The inspectors reviewed procedure 34GO-OPS-005-2S: Power Changes, Revision 18, and using Attachment 1 determined that minimum core flow for about 99.78% RTP was approximately 87%. Continued operation at 99.78% RTP and core flow of 83% (above the APRM rod block line) was a condition that was not analyzed. The inspectors discussed the problem with operations management engineering personnel and the operating crew on shift at the time of the problem. Engineering personnel informed the inspectors that corporate engineering was conducting an evaluation to determine the significance of the problem. The inspectors were also informed that operation in the unanalyzed region of attachment 1 (rated thermal power/core flow) map of the procedure had occurred for about four hours.

The inspectors reviewed corporates analysis of the significance of the problem. The analysis indicated that the bounding transient was a loss of FW heating. Corporate personnel verified, using a computer program, that the core thermal limits presently in effect would not be exceeded during a loss of FW heating transient. The analysis also clearly indicated that operation in the unanalyzed region of the rated thermal power/core flow map was currently bound for all core thermal limits by the limits which are

currently in place in the COLR for Hatch Unit 2. Operation above the APRM rod block line followed with the most limiting transient, reactor core thermal limits would not be exceeded. GE Fuels personnel agreed with corporates analysis.

The inspectors agreed with the assessment that operating above the APRM rod block line was bound by the COLR. The core thermal limit consequences of the problem was minimal. The inspectors also observed that the APRM RPS scram setpoint was about 10% of RTP above the APRM rod block.

Licensee management informed the inspectors that the APRMs alarmed intermittently during the power increase. Also, an alarm on the core thermal power process computer had actuated to alert on shift operating crew that power was above the APRM rod block line.

The inspectors concluded that several deficiencies contributed to the problem. The operators on shift failed to use alarm response procedures and take actions for alarming APRMs and the process computer core thermal power alarm. The inspectors reviewed the applicable alarm response procedures for the alarming APRMs and the process computer. The inspectors concluded that adequate information existed to properly identify and correct the problem.

Prior to the implementation of the new TS the APRM rod block line and alarm points were established with an approximately 3% margin to the unanalyzed region of the procedure. This allowed a buffer zone between the alarm setpoint and the region of the procedure that required immediate exit (unanalyzed). However, this buffer zone was eliminated when the new TS were implemented. In the past it was normal practice for operating crews to increase power to the APRM alarm setpoints and then slowly increase power to rated. Operations management informed the inspectors that operating crews did not receive specific training on the new setpoint change and elimination of the buffer zone. The operating crew did not realize the significance of the alarms.

The inspectors observed that operations personnel had received significant classroom and simulator training for the new TS. To become more familiar with the new TS, the operating crews used the new TS on shift concurrently with the existing TS for several months. The inspectors could not verify whether or not specific training was conducted for this problem. The lack of specific training for this problem may have been a contributor.

A note in section 5.1, of the Power Change procedure, indicated in part that, due to the critical nature of these activities, (power changes) conservative action shall be used. Strict compliance with this procedure is required any time reactor power is changed... The inspectors concluded that on shift operating crew failed to correctly use the procedure and did not display conservative actions with respect to monitoring reactor power.

Step 5.2.2 of the procedure stated in part that, all normal power operation shall be within the region of operation defined on the Power Versus Flow Map of Attachment 1.... The inspectors observed that the on shift operating crew did not maintain parameters within the region of operation as defined on Attachment 1 of the procedure. The inspectors observed that the area above the APRM rod block line identified on attachment 1 of the procedure (where core flow and rated thermal power would be indicated during APRM and CTP alarm conditions) was labeled as an "immediate exit region". The inspectors concluded that operation within this region lasted about four hours and was not immediately exited.

The STAs routinely plotted power versus core flow during power increases. However, in this case the STA conducted a core flow versus RTP plot at about 1:00 a.m. No additional plots were performed during the remainder of the shift at about 7:00 a.m. The inspectors concluded that this was not a demonstration of conservative actions.

Following the problem, operations management issued a BOST document to discuss the issue and to ensure other operating crews were aware of the problem. The inspectors attended several shift turnover sessions when the BOST was discussed. The inspectors concluded the instructions and explanation given to operations personnel were not clear. The instructions presented were not thorough and the BOST contained conflicting statements with respect to management expectations and the consequences of entering the unanalyzed region of the procedures. The statement, "Due to the fact that it (the APRM rod block line) is only an FSAR limit, the line is somewhat fuzzy. If you found yourself a pencil width over the line, I don't think it would be the end of the world.", was considered inadequate by the inspectors.

The inspectors discussed the BOST with the AGM - Operations to gain a better understanding of managements expectations. The inspectors were informed that higher levels of plant management did not routinely read and approve the BOST documents. However, the BOST did not meet managements expectations. The inspectors were informed that future review and approval of plant management would be considered. The inspectors later reviewed an adequate revision of the BOST.

The Unit 2 power operations outside the normal region of operation issue was identified as an example of VIO 50-321,366/96-04-02: Failure to Follow Procedure - Multiple Examples.

The inspectors reviewed the TS and TRM and observed that an amendment had deleted the APRM control rod block function. The inspectors also reviewed the FSAR sections 7.2, 7.5.7 and 7.7 for Unit 1 and 4.4 and 7.6 for Unit 2. The inspectors observed that the FSAR did not reflect that the APRM rod block function was

deleted. The inspectors considered this a minor deficiency. The inspectors observed that there were no differences in the unanalyzed region areas of the FSAR graphs and the rated thermal power/core flow map in plant procedures. No additional documentation is required in this report.

2.13 Inspection of Open Items

The following item was reviewed using licensee reports, inspections, record reviews, and discussions with licensee personnel, as appropriate:

(Closed) VIO 50-321,366/95-22-01: Operators Failure to Follow Procedure - Multiple Examples.

The violation documented two examples of failure to follow procedures. The first example concerned a mispositioned control rod during Unit 2 shutdown activities. The second example concerned a Unit 1 LPCI invertor alarm and trip problem. The inspectors reviewed the licensee's response, dated November 15, 1995. The corrective actions for the mispositioned control rod included temporarily disqualifying the operator, positive discipline for the operator and the supervisor, issuance of an operating order limiting continuous rod withdrawal and insertion, and the use of a verifier. The LPCI invertor alarm was declared inoperable and subsequently repaired. Based on the inspectors review of the licensee's corrective actions, this violation is closed.

3.0 MAINTENANCE (62703) (61726) (92902) (61701)

Maintenance activities were observed and reviewed during the reporting period to verify that work was performed by qualified personnel and that procedures adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify authorization to begin work, provisions for fire hazards, cleanliness, exposure control, proper return of equipment to service, and that limiting conditions for operation were met. The following maintenance activities were reviewed and witnessed in whole or in part:

3.0.1 MWO 29403712: Condensate Booster Pump 2N21C002C

On March 18 - 19, an inspector observed EM personnel performing preventive maintenance for the Unit 2 condensate booster pump. The EM personnel were using preventive maintenance procedure 521PM-N21-018-2N: Condensate System Preventive Maintenance, to change the lubrication oil. The work performed included flushing and cleaning the bearing oil reservoir, the external oil reservoir, and the fill bearing housing. The EM personnel followed the procedure and all work observed was accomplished in a satisfactory manner.

The condensate booster pump is discussed in FSAR 10.4.7.2, no maintenance requirements were listed. There are no TS requirements.

3.0.2 MWO 29502066: Condensate Booster Pump, 2N21C002C

On March 19 - 20, an inspector observed MM personnel performing preventive maintenance for the Unit 2 condensate booster pump. The MM personnel were using preventive maintenance procedure 52PM-N21-017-2N: Condensate Booster Pump And Motor Major Inspection/Overhaul, for disassembly and alignment of "thrust end mechanical seal and coupling". The Assistant Team Leader provided continuous detailed supervision. The maintenance mechanics followed the work procedure and all work observed was performed in a satisfactory manner.

3.0.3 MWO 19600961: RCIC Steam Supply Globe Valve, 1E51-F045

During the week of March 18, an inspector observed MP trouble shoot and investigate the cause of valve 1E51-F045 which failed to operate from the remote shutdown panel. The remote shutdown panel test was conducted per special operation tests procedure 34Sp-030496-CX-1-1S, "Operation of RCIC From Remote Shutdown Panel". Preventive maintenance procedure 52PM-MEL-022-OS: Limitorque Valve Operator Electrical Maintenance, was used during the trouble shooting phase. The MP (electrical and mechanical) examined both the motor control center and the actuator of the motor operated valve. The electrical motor was burned out. The root cause determined by MP was that the torque switch failed to shut off the motor. The torque switch gearing was pinned to the shaft. The pin failed causing the torque switch to slip on the shaft instead of tripping the motor. The MP replace the motor and torque switch assembly. The torque switch gear and shaft assembly was made from one piece of steel that eliminated the pin. After the repairs were completed, the MP conducted a static test using the "Votes" MOV test equipment to verify the new torque switch setting. The motor operated valve test was performed using 53IT-TET-002-OS: Valve Operation Test And Evaluation System (VOTES), procedure. All work and testing observed was accomplished in a satisfactory manner.

The RCIC System is discussed in FSAR 4.7, no maintenance requirements are listed. The TS requirements for the RCIC system and the Remote Shutdown Panel are in Sections B.3.5.3 and B.3.3.3.2 respectively. There were no discrepancies identified with TS and the work observed.

3.0.4 MWO 29600207: Change Capacitors In Vital AC Invertor

On March 21, an inspector observed EP changing the DC capacitors in the vital AC invertor 2R44-S001 using procedure 52PM-R44-007-OS: Vital AC Invertor Preventive Maintenance. The inspector

verified the procedure was being followed and the correct replacement capacitors were used. The torque wrench used had an up to date calibration sticker. The work was performed in a satisfactory manner.

Invertor 2R44-S001 is not classified as Class 1E and is not listed in the FSAR. There are no TS requirements for this invertor.

3.0.5 MWO 1-96-848: Repair Relay, 1A71-K57 in Panel 1H11-P623.

This relay failed causing fuse failure and a PCIS group 2 isolation on Unit 1. The inspectors observed the trouble shooting and repair activities for these problems. The inspectors observed that appropriate caution was observed while working in energized panels and maintenance management oversite was evident. Procedure usage and communications were very good. Deficiencies were not observed during these work activities. The FSAR review documented in paragraph 2.5. identified no deficiencies.

3.1 Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. Witnessed tests were inspected to determine that procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and system restoration was completed. The following surveillances were reviewed and witnessed in whole or in part:

3.1.1 Unit 1, 34SV-E41-002-1S: HPCI Pump Operability

On March 21, operations and maintenance personnel set-up and conducted a monthly operability test of the Unit 1 HPCI pump. In addition, the system engineer and maintenance foreman also followed the test to monitor the data and look for steam leaks to be repaired during the up-coming outage. An inspector observed the licensee personnel conduct the test as required by the procedure. The inspector verified the test run was satisfactorily performed and the data observed was within the TS requirements. The licensee personnel conducted the test as required by procedure. In addition, the inspector walked down the RCIC area and concluded it was well maintained.

The HPCI TS surveillance requirements are listed in Section 3.5.1.8 and 5.5.6. The HPCI system is discussed in FSAR 10.4.7.2. There were no discrepancies identified with the FSAR or TS and the work observed.

3.1.2 Unit 1, 57SV-SUV-004-1S: Reactor Coolant Instrumentation Lines Excess Flow Check Valve Operability

On March 20, an inspector observed I&C maintenance personnel conduct excess flow check valve testing for valves 1B31-F009A, F010A, F011A, and F012A. The inspector verified the test results met the requirements of the acceptance criteria of the surveillance procedure. The I&C technicians performed the surveillance in a professional manner using calibrated M&TE.

The TS requirement for excess flow check valve testing are listed in Section 3.6.1.3.8 for LCO 3.6.1.3. The excessive flow check valves are discussed in FSAR 5.2.3.5.4. There were no discrepancies identified with the FSAR and TS and the testing observed.

3.1.3 Unit 1, 42SV-TET-001-1S: Primary Containment Periodic Type B and C Leakage Tests

On March 20, an inspector observed operations personnel conduct a Type B leak rate test on electrical penetration 1T52X105C. The inspector verified the test results met the requirements of the acceptance criteria of the surveillance procedure. The operations personnel followed the procedure and performed the test in a satisfactory manner using calibrated M&TE.

The Type B leak rate test is discussed in FSAR 5.2.3.4.3 and 5.2-2. The technical specification requirements are listed in Sections 3.6.1 and 5.5. There were no discrepancies identified with the FSAR and TS and the testing observed.

3.1.4 Unit 2, 42EN-R42-002-ON: Vital AC Battery Discharge Test

On March 19, an inspector observed electrical personnel conduct a battery discharge test for battery 2R42-S008. The inspector verified the test met the acceptance criteria of the surveillance procedure. The test was performed in a satisfactory manner using calibrated test equipment.

Battery 2R42-S008 is not classified as 1E and is not listed in the FSAR. There are no TS requirements for this battery.

3.2 Review of Foreign Material Exclusion

On March 14, the inspectors attended a licensee training session for a new FME procedure effective March 15. The training consisted of reviewing the procedure, viewing a video film and a question and answer session. Licensee management informed the inspectors that all site and contract personnel would be required to attend similar sessions to gain an understanding of managements expectations for FME. The inspectors concluded that the training was satisfactory. The inspectors reviewed procedure 10AC-MGR-021-

OS: Foreign Material Exclusion, Revision 0 and procedure 51GM-MNT-002-OS: Maintenance Housekeeping and Tool Control, Revision 11.

On March 21, the inspectors discovered a large piece of clear bubble plastic on the refuel floor. The plastic was rolled up and inside a colored plastic bag. The plastic was similar to material used for packaging of instruments or sensitive equipment. The inspectors informed a HP technician assigned to refuel floor duty. The plastic was immediately removed from the floor. On March 26, the inspectors observed an approximately four foot square piece of clear plastic covering an instrument located adjacent to the Unit 1 spent fuel pool. The instrument was staged for upcoming refuel floor activities. The inspectors observed that one edge of the plastic was attached to the instrument by duct tape. The inspectors informed the refuel floor coordinator who immediately had the plastic removed.

Procedure 51GM-MNT-002-OS: Maintenance Housekeeping and Tool Control, Revision 11, Step 5.2.6 indicated in part, that clear plastic shall not be carried onto the refueling floor unless there is no practical alternative material available. The inspectors concluded that in this case a practical alternative material was available. The inspectors observed that most of the instruments on the refueling floor were covered and protected by plastic that contained colored stripes. Colored or striped plastic was used for ease of identification in case the item was inadvertently dropped into the reactor vessel or into the spent fuel pool.

The inspectors discussed this observation with licensee management. The inspectors were informed that the bubble plastic was used for instrument protection during shipping and was introduced to the refuel floor in an instrument shipping crate. The inspectors observed that the Maintenance Housekeeping and Tool Control procedure was temporarily changed on March 23, to address equipment brought to the refuel floor in shipping containers.

The inspectors concluded that all the criteria for an NCV listed in the Enforcement Policy were not met. NCV 50-321,366/94-11-03: Use of Clear Plastic On Refuel Floor, was documented in April 1994. The recent FME training for site and contract personnel to communicate managements expectations provided an opportunity for prior identification of the problems. This refueling area misuse of clear plastic material issue was identified as another example of VIO 50-321,366/96-04-02: Failure to Follow Procedure - Multiple Examples.

During the week of March 25, the inspectors discussed the FME procedure requirements with several contractor and site personnel that were performing work in areas that required FME controls. Although the inspectors did not identify instances where FME procedural requirements were not met, the inspectors concluded

that some of the personnel did not have a clear understanding of the FME requirements. This was discussed with licensee management. Some members of licensee management conducted tours and discussed the FME process with site and contractor personnel. Management also concluded that their expectations were not met. Some personnel had been assigned work activities prior to scheduled training for FME. The licensee removed several groups from work activities and conducted FME training. Other work groups were given retraining.

During the week of March 25, the inspectors toured the Unit 1 torus proper to observe FME work control process and equipment staging for torus cleaning and coating. A large number of tools, equipment and other items were placed inside the torus. The inspectors observed that the torus was not controlled as an FME area as described in the FME procedure. The inspectors did not identify where equipment, tools and other material in the torus was inspected, logged or otherwise accounted for. The inspectors concluded the torus was used and treated as a general work area. At the time of the inspection, ECCS equipment was not in service or aligned to the CST.

The inspectors discussed this issue with the supervisor in charge of torus work activities. The inspectors were informed by the area work supervisor that after the completion of the work activities divers would conduct a thorough inspection of underwater areas. Additionally, thorough inspections of other torus areas would be completed prior to torus closure.

The inspectors discussed this issue with licensee management to gain a better understanding of managements expectations. The inspectors were informed that the activities observed in the torus did not meet managements expectations and corrective actions were initiated. A few days later members of management toured the torus area to observe work activities and assessed FME controls. This tour resulted in a short stoppage of work activities. An assessment of FME controls and rigging issues was completed and on-the-spot corrections were completed.

The inspectors identified a weakness in some aspects of the FME program. The inspectors concluded FME requirements were not clear to all personnel. It was evident that some personnel did not clearly understand all aspects of the procedure requirements. Management was initially responsive to the specific FME problems that were identified. A broader FME problem was later evident to management and the actions taken above were performed to strengthen this area.

3.3 Inspection of Open Items

The following items were reviewed using licensee reports, inspections, record reviews, and discussions with licensee personnel, as appropriate:

3.3.1 (Closed) LER 50-321/95-01: Personnel Error Results in Missed TS Surveillance.

This item was issued when the ISTs for RHR pumps 1B and 1D were not performed within the required interval of three months. The inspectors reviewed the licensee's documentation, dated February 6, 1995. The cause of the occurrence was personnel error. The licensees corrective actions included counseling the SS on the importance of paying attention to detail and verifying the success of the June test. Based on the inspectors review of the licensee's actions, this item is closed.

3.3.2 (Closed) LER 50 366/95-07: Actuation of Engineered Safety Features Result From a Trip of Reactor Protection System Power Supply.

This item was issued when the MG set bus B output breakers for the unit 2 RPS tripped. The inspectors reviewed the licensee's documentation, dated November 28, 1995. The licensee's corrective action included the installation of a new modified voltage regulator. The modification consisted of a fixed resistor in place of a potentiometer. The MG set was successfully load tested for two days at a power factor of 0.6. The MG set was returned to service. Based on the inspectors review of the licensee's actions, this item is closed.

4.0 ENGINEERING (37551) (37828) (37700) (61715) (92903) (92700)

On-site engineering activities were reviewed to determine their effectiveness in preventing, identifying and resolving safety issues, events and problems.

4.1 ILRT Final Report

The inspectors reviewed the ILRT final report for Unit 2, dated January, 1996. The inspectors documented in IR 50-321,366/95-23 the observations made during the performance of the test. The inspectors review of the final test results verified that the test was performed properly and the results were consistent with the initial observations documented in IR 50-321,366/95-23. The test indicated the final as-left leakage rate was 0.3175 weight percent per day, which was less than the acceptance limit of 0.9000 weight percent per day. The test also indicated that the final as-found rate, factoring in the results of the local leakage rate testing

program, was 0.6707 weight percent per day. This was less than the acceptance limit of 1.2000. The inspector concluded that the ILRT final report verified that the Unit 2 containment was successfully tested and the results were within acceptance criteria.

The inspectors reviewed Unit 1 and Unit 2 FSAR with respect to ILRT testing. The inspectors observed that Unit 1 FSAR section 5.2.5.1 indicated the containment leak rate test program is described in the TS sections 3.7 and 4.7. The correct section for the new TS is section 3.6. This deficiency was considered minor and no additional documentation is required in this report. No additional deficiencies were identified.

4.2 RHR Valves 2E11-F028A and F021B Review

The Inspectors reviewed the post modification performance of RHR valves 2E11-F028A and B, Torus Cooling and Spray Isolation. Both valves were extensively modified during the Unit 2 fall 1995 refueling outage. Operators manipulated the valves on several occasions for torus cooling with no identified problems. The inspectors did not identify any deficiencies or problems since the Unit 2 refueling outage. The inspectors concluded that the valves were satisfactorily performing their intended function. The inspectors reviewed FSAR section 6.2 with respect to this issue and no deficiencies were observed.

4.3 TIL 1129-3 Potential RFPT Rotor Keyway Cracking

The inspectors reviewed TIL 1129-3, Potential Rotor Cracking in Shaft Keyways For Mechanical Driven Steam Turbines With Shrunk-on Couplings. The TIL was applicable to the A and B RFPTs for both units. However, it was not applicable to the ECCS steam driven turbines. The TIL stated that all identified failures to date were attributed to misalignment. The TIL contained recommendations to inspect the shafts and to align the coupled rotors properly to minimize bending stresses.

The TIL recommended actions were completed for the Unit 2 RFP shafts during the fall 1995 refueling outage. No cracks were observed on either RFPT. The TIL actions are planned for Unit 1 RFP shafts during the spring 1996 refueling outage.

The inspectors discussed the TIL and Unit 2 RFPT performance with engineering personnel. The inspectors concluded the problems identified in the TIL were not a problem for the Unit 2 equipment. The results of the inspection will be available for review following the Unit 1 RFPT inspection. The inspectors reviewed FASR section 10.4 and did not identify differences between the plant practices and procedures.

4.4 Test of Unit 1 RCIC System From Remote Shutdown Panel

The inspectors documented in IR 50-321,366/95-27, paragraph 4.1, that 42SP-120195-PP-1S, Unit 1 Remote Shutdown System Logic Test, was successfully performed. However, this procedure verified the logic functioned properly but did not test actual operation of the valves.

On March 18, the inspectors observed a test of the RCIC system from the Unit 1 RSDP. The test activities were controlled by special purpose procedure 34SP-030496-CX-1-1S: Operation of RCIC from Remote Shutdown Panel. The test was conducted as part of the licensees continued investigation of a previous problem identified during the last Unit 2 refueling outage. The procedure was not successful due to a technical error. The RCIC system was not required to be tested until the startup operability requirements of the new TS, following the refueling outage.

The procedure did not contain the required step to place the normal - emergency transfer switch for valve F119, Steam to Turbine Bypass valve, in the emergency position. As a result the F119 valve did not open. An interlock prevented the F045 valve, Steam to Turbine, from opening and prevented system operation. Operations personnel then tested the operation of the F045 valve from the CR. During this test the F045 valve failed (see paragraph 3.0.3). The system engineer, maintenance and electrical maintenance personnel initiated troubleshooting activities.

Following the maintenance activities, another special purpose procedure 34SP-031996-CX-1-1S: Operation of the RCIC Valve, 1E51-F045, From the Remote Shutdown Panel, was issued. The new SP procedure corrected the previous discrepancies with the normal - emergency transfer switch. The performance of this procedure was successful.

The inspectors reviewed DCR 1H89-192, completed in March 1990, for installing the F119 valve and support equipment. In March 1990, DCR 1H90-072, completed work activities initiated by DCR 1H89-192. The inspectors verified that post modification testing was completed following the DCRs.

The inspectors observed that the DCRs listed several plant procedures for revision to reflect the DCR work activities. The inspectors observed that system operating procedures and surveillance procedures were listed. However, emergency operating procedures were not listed. The inspectors also reviewed a procedure request form for a new procedure dated December 1990. The form indicated that Emergency Operating Procedure 31EO-EOP-002-1S was to be deleted and replaced by procedure 31RS-OPS-001-1S: Shutdown From Outside Control Room, Revision 0, dated December 12, 1990. The inspectors reviewed that procedure and determined that the F119 valve and normal - emergency transfer

switch for the valve, which were installed by the above two DCRs, were not included in the procedure. The inspectors also reviewed the current revision, revision 3, of the procedure, dated December 1, 1994, and observed that it did not contain the required steps.

On December 2, 1995, the licensee discovered several deficiencies during surveillance and maintenance troubleshooting activities from the Unit 2 RSDP. A predecisional enforcement conference was conducted on December 28, 1995. IR 50-321,366/95-23 and 95-26 documented inspector findings and observations and a violation with respect to this problem. Part of the licensee investigation and corrective actions included a broadness review for DCR work activity. The licensee reviewed five DCRs for Unit 1 and conducted logic testing from the RSDP. The testing included part of the RCIC system. It was not clear whether or not the licensee included a review of plant procedures during these activities that may have identified the procedural deficiency. Apparently the normal procedure review process since December 1990, failed to identify the problem.

The inspectors concluded engineering personnel responsible for DCR review failed to identify applicable procedures to be revised. The licensee had previous opportunities to identify this procedure deficiency.

The inspectors concluded that the problem presented minimal safety significance. Procedures to be used in the event of a control room abandonment require operators to manually manipulate numerous valves and components. Operators were trained and examined on taking manual control of failed equipment under similar circumstances. Operator performance in this area was generally good.

The inspectors concluded that all the criteria for an NCV listed in the Enforcement Policy were not met. This item was identified as VIO 50-321/96-04-03: Inadequate Procedure For Operating RCIC from The Remote Shutdown Panel.

The inspectors reviewed the Unit 1 FSAR section 4.7 with respect to this problem. No discrepancies were identified between the FSAR and the plant practices and procedures.

4.5 Modifications

The inspectors continued to review and observe the ongoing modification activities. The inspectors reviewed DCR and MDC packages and observed portions of the implementation activities. These reviews included 10 CFR 50.59 review, unreviewed safety question criteria, required testing and job task activities. The observed work included work process procedures, installation activities and required testing activities. Among the DCRs reviewed and installation activities observed were:

DCR 94-37: TSI Abatement (Removal)
DCR 94-44: TSI Abatement (Rewiring)
DCR 94-48: Lower ATWS Recirculation Pump Trip
DCR 91-69: Unit 1 RSCS Hardware Removal
DCR 95-17: Replace 1A EDG Generator

The inspectors verified that the 10 CFR 50.59 safety evaluations were adequate, verified that the modifications were reviewed and approved in accordance with the licensee's procedural requirements, that applicable design bases were considered, and that appropriate post-modification testing requirements were specified. The inspector also verified that work instructions, including drawings and specifications, were adequate to implement the modification.

The inspectors concluded that the DCRs reviewed were being implemented in accordance with the licensee's design change procedures and requirements.

4.6 Modification Installation and Testing

During the last Unit 2 refueling outage ending in November 1995, the licensee performed modifications to the HPCI and RCIC systems. Both systems were change from an analog control to a digital control process under DCR 92-091 and 093. The inspectors observed and reviewed the post modification operation of the HPCI and RCIC systems. The inspectors concluded that system operation was satisfactory. Performance during surveillance operations did not identify any discrepancies.

4.7 Battery Testing

On February 13, 1996, a battery load test cell shorted and a small self contained electrical fire occurred (mostly smoke) on Unit 1. The fire was quickly extinguished by the personnel on the scene and was confined to the load test cell relay compartment.

The inspector reviewed licensee actions following the problem. The inspectors reviewed procedures 42EN-R42-002-0N: Vital AC Battery Discharge Test, and 42SV-R42-009-0S: Combined Service-Performance and Modified Performance Tests, used during the test. The battery discharge test procedure was used when testing the non-safety related, non-TS vital AC batteries. The second procedure is used for the safety related, TS batteries. The fire resulted in extensive damage to the load cell and required that the cell be sent offsite for repairs. The inspectors observed from the review that the safety related procedure contained diagrams that direct personnel on the proper method for connecting leads for the various battery tests. The non-safety related procedure only states "connect load test cables to battery terminal". In this case the maintenance personnel incorrectly

connected the test load leads. These connections were approved by the test engineer prior to energizing the test leads.

The inspector concluded that the non-safety related procedure did not contain specific guidance to prevent the problem. This problem appeared to be a single instance of inattention to detail on the part of the test engineer. The licensee informed the inspectors that the procedure was being revised to include specific guidance for load connections. The inspectors concluded this problem resulted in little safety or fire hazard significance. However, other instances or circumstances may present more significant personnel or equipment safety concerns.

4.8 Load Path for EDG 1A Generator Removal from EDG Building

The inspectors identified an issue in IR 50-321,366/95-02, involving the removal of the generator from the 1A EDG for replacement with a new one. At the time of the previous inspection the licensee had not developed a heavy load pathway analysis. The licensee later completed the analysis. The inspectors reviewed the document which described the load pathway to follow when removing the old generator and replacing the new generator. The load crane was placed on the east side of the EDG building. The path to follow over the building was outlined with red paint, the height was appropriately restricted and a load test was performed prior to the lift. The inspectors concluded that the preplanning was effective. The established load path was appropriate and was controlled with adequate safety oversight by supervisor and engineering personnel.

5.0 PLANT SUPPORT (71750) (92904) (93702)

Security, health physics and other plant support activities were routinely observed and monitored during the report period. These activities included plant security access controls, locked high radiation area doors, proper radiological posting, personnel frisking upon exiting the RCA, and status of various FP equipment. The observations and monitoring were performed in conjunction with the conduct of other inspection activities.

5.1 HP Observations During Preparations for Refueling

The inspectors reviewed applicable procedures and observed HP activities during Unit 1 refueling preparations. The inspectors observed equipment staging, established RCA boundaries and controls and HP assistance and support to plant personnel. The inspectors observed plant surveys were current and clearly provided information to support ALARA initiatives. Except for some minor deficiencies dealing with tools, equipment and clothing lying across the RCA boundary, HP support and contamination control were good. The deficiencies observed were minor in nature and appeared to be a lack of attention to detail by personnel

removing contaminated clothing when exiting the RCA. The deficiencies were discussed with HP technicians and management. The deficiencies were immediately corrected.

The inspectors entered the drywell to observe work control processes and work in progress. The inspectors observed that HP support and controls such as postings, markers, and surveys were good.

5.2 HP Indoctrination and Plant Tour for New Contract Personnel

HP management initiated a new contractor indoctrination and plant tour for first time contract personnel at plant Hatch. The indoctrination and tour was a pilot program to begin as soon as contractors were badged for unescorted access to the plant. The tours were conducted by HP supervisors, foreman or technicians and lasted about one hour. The initiative was designed to stress correct radiation practices and identify areas of potential problems that should be avoided. For example, some items discussed were RWP usage, correct dosimetry placement, frisking techniques, tool control, and building layout. The indoctrination and tour was completed for between 70 and 80 personnel.

The inspectors attended a tour for eight GE personnel conducted by a HP technician on March 19. During a discussion with the contractor personnel the inspectors learned that this was the first work at a nuclear plant for three of the individuals. The inspectors discussed areas for possible improvements with HP management. Licensee management indicated positive feedback was received from personnel that attended the tours.

The inspectors concluded that the new pilot program initiative demonstrated managements concern for improvement in the HP and contractor performance area.

5.3 Airborne Contamination Event of March 28, 1996.

10 CFR 20.1501(a) requires each licensee to make or cause to be made such surveys as (1) may be necessary for the licensee to comply with the regulations and (2) are reasonable under the circumstances to evaluate the extent of radioactive hazards that may be present.

An NRC inspection was conducted to followup on the potential radiological consequences of an airborne contamination event that occurred while inspecting a damaged fuel rod in the Unit 1 spent fuel pool. The inspector reviewed the licensee's actions to determine if the licensee had performed an adequate analysis of the event.

Description of Event:

Fuel bundle LZY612 had been identified as containing a leaking rod during the operating cycle. The bundle was inspected for debris and cladding damage. Rod G4 of this bundle was lifted approximately 2 inches in order to inspect the portion of the rod hidden by the bundle spacer.

At 1325 hours on March 28, 1996, the end cap of the rod broke and the RM-14 frisker and CAM on the refueling floor alarmed. The reactor building vent plenum radiation monitor also alarmed. The CAM and the reactor building vent monitors quickly reset. The refueling floor coordinator informed the HP technician on the floor that the fuel rod end plug of the rod being withdrawn for visual inspection had broken off. The main control room was notified of the conditions. While the contractors were attempting to insert the damaged fuel rod back into the bundle to place it in a safe condition, approximately 21 inches of the rod broke off and several fuel pellets fell out of the broken rod into the fuel bundle housing and onto the spent fuel pool floor. An inspection was conducted to locate the pellets. Two pellets were recovered and the pellets and broken rod were placed in a locked container and stored in the spent fuel pool.

The refueling floor Health Physicist observed that the CAM noble gas monitor alarmed and HP began taking airborne radioactivity samples using a portable backup air sampler using particulate and charcoal filter media. Air sample results were evaluated for gross activity on the refueling floor and then forwarded to the counting laboratory for isotopic analysis. Isotopic analysis of the backup air samples confirmed submersion gases, primarily Xenon 133, present at a concentration of 2.43E-06 uCi/cc (microcuries / cubic centimeter). The source of the airborne radioactivity was determined to have resulted from the breaking off of the fuel rod end plug which allowed gas to escape from the damaged fuel rod. Subsequent to initial alarms, no increase in area radiation or loose surface contamination due to the initial release or to the loose fuel pellets was detected on the refueling floor or adjacent areas.

All workers exiting the refueling floor were surveyed for contamination. All but one were uncontaminated. One worker was contaminated in the head region due to the retention of some submersion gas. Approximately 15 minutes after the initial whole body survey (frisk), the worker was frisked again and determined to be uncontaminated after the low levels of gas had dissipated. Workers in the immediate vicinity of the event were wholebody counted for internal radioactivity and none was detected.

The inspector attended a licensee fact finding meeting and discussed the sequence of events with cognizant personnel involved. The inspector also toured the facility to observe the

physical out lay of the refueling floor and individually discussed the event with several workers who had been involved in the event. Workers were in the process of inspecting another fuel bundle at the time of the tour. The inspector observed ventilation flow paths, portable survey instrumentation used during the event, and reviewed time line chart paper from the refueling floor CAM and the reactor building vent plenum monitor. Using vent plenum monitor results, the licensee calculated approximately 0.34 Curies of Xenon 133 exited the reactor building ventilation stack. Based on the relative short half-life for Xenon 133 of approximately 5.25 days, and the dispersement for the quantity released, the licensee determined no detectable environmental increases resulted from this event.

After a review of survey results reviewed and interviews with cognizant personnel, the inspector concluded no particulates or iodines were detected as a result of this event.

Also, after reviewing the sequence of events and the actions taken by the licensee, the inspector concluded the licensee conducted adequate analysis of the event to characterize the root cause and performed surveys necessary to evaluate the extent of radioactive hazards that may have been present.

No violations or deviations were identified.

6.0 OTHER NRC PERSONNEL ON SITE

On March 21 and 22, the NRR Senior Project Manager for Hatch, Mr. K. Jabbour visited the site. Mr. Jabbour met with the resident staff and discussed plant status and generic issues. He toured the plant, attended licensee management plant status meetings and reviewed plant documents.

7.0 REVIEW OF UFSAR COMMENTMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. During the inspection period February 18 - March 30, 1996, the inspectors reviewed the applicable sections of the UFSAR that related to the inspection areas discussed in this report. The following inconsistency was noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors.

Unit 2 FSAR Figure 3.7A-7: Post-Seismic Event Plant Procedures, contains an outline of the order of actions to be taken after a seismic event. Plant Abnormal Operating and Emergency Operating Procedures did not reference these steps. However, alarm response procedures did. Operator actions and followup activities

following a seismic event, as outlined in the FSAR, were not clearly defined in the plant procedures. The differences between the plant operating procedures, the FSAR diagram, and the vendor diagram were considered minor. The possibility that these differences could cause confusion on the part of licensee personnel was considered minimal (paragraph 2.9).

8.0 EXIT

The inspection scope and findings were summarized on April 8, 1996, by Mr. B. L. Holbrook, with those persons indicated by an asterisk in paragraph 1. Interim exits were conducted on March 22, March 30, and (via telephone) April 4, 1996. The inspector described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
VIO	50-321\96-04-01	Open	Failure to Complete Technical Specification Surveillance Procedure for Secondary Containment Integrity (paragraph 2.6).
VIO	50-321,366/96-04-02	Open	Failure to Follow Procedure - Multiple Examples (paragraph 2.12 and 3.2).
VIO	50-321/96-04-03	Open	Inadequate Procedure For Operating RCIC from The Remote Shutdown Panel (paragraph 4.4).
VIO	50-321,366/95-22-01	Closed	Operators' Failure to Follow Procedure - Multiple Examples (paragraph 2.13).
LER	50-321/95-01	Closed	Personnel Error Results in Missed TS Surveillance (paragraph 3.3.1).
LER	50 366/95-07	Closed	Actuation of Engineered Safety Features Result From a Trip of Reactor Protection System Power Supply (paragraph 3.3.2).

9.0 ACRONYMS

AC - Alternating Current
AGM - Assistant General Manager
APRM - Average Power Range Monitor
ATWS - Automatic Trip Without Scram
BOST - Beginning Of Shift Training
CAM - Continuous Air Monitor
CCW - Component Cooling Water
CFR - Code of Federal Regulations
COLR - Core Operating Limit Report
CST - Condensate Storage Tank
CTP - Core Thermal Power
CR - Control Room
DC - Deficiency Card
DCR - Design Change Request
DPM - Disintegrations per Minute
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
ED2 - Edition 2
EFCV - Excess Flow Check Valve
EHC - Electro Hydraulic Control
EM - Electrical Maintenance
EP - Electrical Personnel
ERT - Event Review Team
ESF - Engineered Safety Feature
FME - Foreign Material Exclusion
FSAR - Final Safety Analysis Report
FP - Fire Protection
FW - Feedwater
GE - General Emergency
HP - Health Physics
HPCI - High Pressure Coolant Injection
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
ILRT - Integrated Leak Rate Test
IR - Inspection Report
IST - Inservice Test
LCO - Limited Condition For Operation
LER - Licensee Event Report
LPCI - Low Pressure Coolant Injection
MDC - Minor Design Change
MG - Motor Generator
MM - Mechanical Maintenance
MP - Maintenance Personnel
M&TE - Measurement and Test Equipment
MWT - Megawatts Thermal
MWO - Maintenance Work Order
NCV - Non-Cited Violation
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
OBE - Operating Basis Earthquake

PASS - Post Accident Sampling System
PCIS - Primary Containment Isolation System
PDR - Public Document Room
PRB - Plant Review Board
RCA - Radiological Control Area
RCIC - Reactor Core Isolation Cooling
RCS - Reactor Coolant System
RFPT - Reactor Feedwater Pump Turbine
RG - Regulatory Guide
RHR - Residual Heat Removal
RPS - Reactor Protection System
RR - Reactor Recirculation
RSCS - Rod Sequence Control System
RSDP - Remote Shutdown Panel
RTP - Rated Thermal Power
RWP - Radiation Work Permit
SBLC - Standby Liquid Control
SOR - Significant Occurrence Report
SOS - Superintendent On Shift
SJAE - Steam Jet Air Ejector
SP - Special Purpose
SPDS - Safety Parameter Display System
SR - Surveillance Requirement
SRV - Safety Relief Valve
SS - Shift Supervisor
SSS - Shift Support Supervisor
STA - Shift Technical Advisor
SV - Surveillance
TRM - Technical Requirement Manual
TS - Technical Specifications
TSI - Thermal Science Industries
TSIP - Technical Specification Improvement Program
TSR - Technical Surveillance Requirement
TIL - Technical Information Letter
UFSAR- Updated Final Safety Analysis Report
VIO - Violation