ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-416
License No.:	NPF-29
Report No.:	50-416/96-20
Licensee:	Entergy Operations, Inc.
Facility:	Grand Gulf Nuclear Station
Location:	Waterloo Road Port Gibson, Mississippi
Dates:	November 10 through December 21, 1996
Inspectors:	J. Tedrow, Senior Resident Inspector K. Weaver, Resident Inspector M. Runyan, Reactor Inspector G. Good, Senior Emergency Preparedness Analyst
Approved By:	P. Harrell, Chief, Project Branch D Division of Reactor Projects

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Grand Gulf Nuclear Station
NRC Inspection Report 50-416/96-20

The inspectors evaluated aspects of licensee operations, maintenance, surveillance, engineering, and plant support activities. This report covers a 6-week period of resident inspection.

Operations

- Observed activities were generally conducted professionally and safely. Operators were observant, cognizant of plant and equipment conditions, and took appropriate actions (Section O1.3).

- Operator response for an inaccurate condensate storage tank (CST) level indication was poor since unreliable indications were known before CST level transmitter drift contributed to losing control rod drive (CRD) pumps on low suction pressure (low CST level) which precipitated a manual reactor scram (Section O1.3).

- The material condition of Residual Heat Removal (RHR) System C components was good and housekeeping in the RHR Pump C room was good (Section O2.1).

- Corrective action review board (CARB) members provided indepth questions concerning generic implications, events leading to the problems identified and proposed corrective actions during the observed CARB meeting. The board members were aggressively pursuing the resolution to the issues presented (Section O7.1).

Maintenance

- Performance of observed maintenance work activities was satisfactory and conducted in accordance with the instructions and procedures provided in the work packages (Section M1.1).

- Operations, maintenance, and engineering personnel performing the reactor vessel inservice leak test were knowledgeable of all requirements associated with the test and demonstrated proficiency in test performance and effective communication. The prejob meeting conducted prior to the test was thorough and provided the appropriate level of detail concerning hold time requirements and work activities to the personnel involved (Section M1.2).

- Poor process controls governing painting practices were identified in that, freshly painted safety-related components (i.e., reactor core isolation cooling (RCIC) system motor-operated valves (MOVs), turbine, and turbine governor throttle valve) were not evaluated or required to be evaluated for impact on component operability (Section M2.1).

Engineering

- Engineering personnel were technically knowledgeable of component and containment leakage acceptance criteria and knowledgeable of the status and condition of components required to be Type B and C leak tested. The calculations for the overall containment leakage were technically sound (Section E1.1).

Plant Support

- The licensee had the capability to perform onshift dose assessments using real-time effluent monitors and meteorological data (Section P3.1).

- In general, radiological areas were properly posted, personnel were following radiation work permit requirements, and displayed good radiation worker practices. However, survey maps displaying current radiological conditions were not properly updated for several radiation areas. Health physics technicians were knowledgeable of current plant radiological conditions (Section R1.1).

Report Details

Summary of Plant Status

The plant began this inspection period in the refueling condition (Mode 5). The reactor was taken critical at 7:12 a.m. on November 27. At 9:04 a.m. on November 27, control room operators manually inserted a reactor scram when CRD system pressure was lost (see Section 01.2 for details of the reactor scram). Following repairs to correct a failed CST level instrument, the reactor was restarted and was taken critical at 7:21 p.m. on November 27. Power operation (Mode 1) was commenced at 11:48 p.m. on November 29. The plant remained at power for the remainder of this inspection period.

I. Operations

O1 Conduct of Operations

O1.1 Control of Plant Operations (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent observations of ongoing plant operations, including control room observations, attendance of the daily status meetings, and plant tours. All observed activities were conducted professionally and safely. In general, operators were observant, cognizant of plant and equipment conditions, and took appropriate actions.

O1.2 Reactor Scram Due to Loss of CRD System Pressure

a. Inspection Scope (93702)

At 9:04 a.m. on November 27, 1996, during a plant startup with the reactor critical on intermediate range six, operators manually scrammed the reactor. The inspectors responded to the control room and verified plant conditions, operator response to the event, control room communications, supervisory effectiveness, and compliance with reporting requirements. Licensee implementation of the following procedures was observed:

- Off Normal Event Procedure 05-1-02-IV-2, "Control Rod/Drive Malfunctions," Revision 102
- Off Normal Event Procedure 05-1-02-I-1, "Reactor Scram," Revision 101.

b. Observations and Findings

Operators noticed that the inservice CRD B pump had automatically tripped. Since proper CST level was indicated in the control room (25 feet), and abnormal suction strainer differential pressure was annunciated, operators believed that the pump had tripped due to low suction pressure because of a clogged suction strainer. The CRD A pump was started to restore CRD header pressure; however, CRD A pump subsequently tripped on low suction pressure. Operators were dispatched to check CST level indication at the remote shutdown panel where it was noted that level indicated 19 feet (normal CST level 26-30 feet, CRD suction piping 19 feet). Due

to the loss of CRD header pressure from the CRD pumps tripping, several control rod hydraulic control unit low pressure accumulator faults were received. Operators manually scrammed the reactor to comply with Technical Specification (TS) 3.1.5 and off-normal event procedures. Subsequent troubleshooting revealed that the single CST level transmitter for control room indication, alarm, and computer point, had failed.

The inspectors arrived in the control room shortly after the reactor scram and verified stable plant parameters. Operator response to the problem was noted to be in accordance with the alarm response procedures and TS.

The licensee's investigation concluded that the control room CST level transmitter was faulty and provided drifting level indication. The licensee was unable to calibrate the transmitter so it was replaced. This transmitter was classified as nonsafety-related and provided single indication and alarm functions to the control room. Other CST level transmitters existed for the remote shutdown panel, RCIC, and high pressure core spray systems which are safety-related and utilize separate sensing lines to the CST; however, the indicators were either not in the control room or were not scaled to provide comparable CST level indication.

During observation of the corrective maintenance for the failed CST level transmitter, the inspectors noted that the work package had been initiated the day before the reactor scram had occurred. The initial scope of the work package included troubleshooting the safety-related remote shutdown panel CST level indicator (1C61-R102) which had failed a channel check with the control room CST level indicator (1P11-R601) on November 26. The two level instruments differed by 4 feet. Later on November 26, calibration checks on the remote shutdown CST level instrumentation were completed satisfactory which indicated that the control room CST instrumentation was inaccurate. Control room operators were notified of the discrepancy. The work package was modified to include a calibration check of the transmitter associated with the control room CST indication. Since no TS were associated with this instrument, work was not immediately started. During the night of November 26, reactor operators noted that the control room CST level indicated an overflow level of 31 feet, yet no flow was evident to the radwaste sumps as it should have been. Although an adverse condition document was initiated for this discrepancy, operating personnel did not initiate compensatory measures to provide for accurate CST level indication such as frequent monitoring of the remote shutdown panel indicator. On the morning of November 27, the work package to troubleshoot the control room CST level transmitter was finished and sent to the field to begin work. The CRD pumps tripped and the reactor was scrammed before this work was initiated.

O1.3 Conclusions on the Conduct of Operations

Operations were conducted in a safe and professional manner. All observed activities were conducted professionally and safely. Overall, operators were

observant, cognizant of plant and equipment conditions, and took appropriate actions. However, the inspectors considered the operator response for the inaccurate CST level indication to be poor since operators were aware of the unreliable indication and failed to take compensatory CST level readings which could have prevented the reactor scram.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdown (71707)

The inspectors walked down accessible portions of RHR System C using Procedure 04-1-01-E12-1, "Residual Heat Removal C," Revision 104, and Piping and Instrument Diagrams M-1085C, Revision 11, and M-1085D, Revision 3, "Residual Heat Removal System, Unit 1."

The inspectors found that valve identifications and valve positions were appropriately identified in Procedure 04-1-01-E12-1 and that the applicable valves were properly labeled and positioned in the field. The inspectors found that the material condition of the components observed was good and that housekeeping in the RHR Pump C room was good. No problems were identified during the walkdown.

O7 Quality Assurance in Operations

O7.1 Licensee Self-Assessment Activities (71707)

During this inspection period, the inspectors observed/reviewed multiple self-assessment activities including:

- CARB meeting for Condition Report (CR) 1996-0215 and CR 1996-0381
- Plant safety review committee meeting for plant restart following reactor scram.

In general, these meetings were conducted appropriately. The inspectors noted that the CARB members provided indepth questions concerning generic implications, events leading to the problems identified, and proposed corrective actions. The inspectors concluded that the board members were aggressively pursuing resolution to the adverse conditions presented.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Maintenance Comments

a. Inspection Scope (62707)

The inspectors observed portions of Work Order 178625: Troubleshoot inaccurate CST level indication in accordance with Procedures 06-IC-1C61-R-0006, "Condensate Storage Tank Level (Remote Shutdown Meter) Calibration," Revision 100, and 07-S-53-P11-6, "Condensate Storage Tank Level," Revision 7.

b. Observations and Findings

Performance of observed maintenance work activities was satisfactory and conducted in accordance with the instructions and procedures provided in the work package.

The inspectors questioned licensee personnel concerning maintenance rule program requirements in regard to the failed CST transmitter (i.e., maintenance preventable functional failure). The licensee indicated that the damaged A CRD pump (bearing failure due to pump cavitation, refer to Section 01.2) was considered a maintenance preventable functional failure in that the loss of system function was due to lack of timely response to known problems. The inspectors considered this classification appropriate.

M1.2 Surveillance Comments

a. Inspection Scope (61726)

The inspectors observed the performance of portions of the surveillance activities, as specified below:

- Procedure 03-1-0116, "Reactor Vessel In-Service Leak Test," Revision 100
- Procedure 06-OP-1P75-R-0004, Attachment IV, "Standby Diesel Generator 12, 18 Month Functional Test - Test [illegible] Loss of Offsite Power and ECCS Initiation Signal," Revision 101
- Procedure 06-OP-1E51-R-0005, "RCIC Pup Low Pressure Flow Verification Test," Revision 100.

b. Observations and Findings

The inspectors noted that the test procedures provided clear guidance and properly implemented TS requirements. Measuring and test equipment were verified to be within its current calibration cycle. The inspectors found that the operations,

maintenance, and engineering personnel, performing the reactor vessel inservice leak test, were knowledgeable of all requirements associated with the test, demonstrated proficiency in test performance, and utilized effective communication. The inspectors found that the prejob meeting conducted prior to the test was thorough and provided the appropriate level of detail concerning hold time requirements and work activities to the personnel involved. The surveillance tests were successfully performed and no problems with the test activities were identified.

c. Conclusions

Personnel performing the reactor vessel inservice leak test were knowledgeable of all requirements associated with the test, demonstrated proficiency in the test performance, and utilized effective communication. The test prejob meeting was thorough and provided the appropriate level of detail concerning hold time requirements and work activities.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Painting Activities on Safety-Related Equipment (71707)

During a routine tour of RCIC system room, the inspectors noted that painting was ongoing on RCIC system components (i.e. MOVs, RCIC turbine, and RCIC turbine governor throttle valve.) The inspectors questioned licensee personnel if the RCIC system had been evaluated to determine the effect of the painting activities on system component operability and if a requirement existed for verification of operability following painting activities on safety-related components. The licensee responded that no written requirement existed and that in the case of the RCIC system no operability verification had been performed. However, during the period that painting was ongoing, operations personnel performed several routine surveillance tests with no equipment problems identified. The inspectors concluded that not verifying the impact on operability following painting of safety-related components was a poor work control practice, since industry experience has shown that painting activities have in the past rendered safety-related equipment inoperable. Licensee management agreed with the inspectors' conclusion and stated they would review the work control process to determine if changes were necessary.

M8 Miscellaneous Maintenance Issues (92902)

(Closed) Inspection Followup Item (IFI) 50-416/95012-02: followup on the licensee's activities to replace worn parts on the RCIC pump mechanical overspeed trip device and to revise preventive maintenance procedures. As discussed in NRC Inspection Report 50-416/95016, the licensee replaced the worn parts for the overspeed trip device. The licensee revised Procedures 07-S-14-92, "Inspection and Lubrication of Terry Turbine Throttle Trip Valve," Revision 1, and 07-1-24-E51-

C002-1, "Periodic Retorquing of RCIC Turbine Flanges," Revision 2, to require periodic checks of critical tolerances and tightness of important bolts on the trip and throttle valve. The licensee was still evaluating how to check the wear surfaces on the mechanical overspeed trip device and has decided to rely on visual examinations in the interim. The inspectors determined that the corrective actions were adequate.

III. Engineering

E1 Conduct of Engineering

E1.1 Reviews of Engineering Evaluations

a. Inspection Scope

Using Inspection Procedure 37551, the inspectors interviewed engineering personnel and reviewed the overall containment leakage data and calculations associated with the leak rate testing performed during Refueling Outage (RFO) 8. In addition, the inspectors reviewed the documentation of the test results and the program description provided in Procedure 17-S-05-1, "Local Leak Rate Test Program," Revision 102.

b. Observations and Findings

The inspectors found engineering personnel technically knowledgeable of component and containment leakage acceptance criteria and knowledgeable of the status and condition of components required to be Type B and C leak tested. The overall calculations were technically sound and as-left component leakage rates were within the acceptance criteria specified in Procedure 17-S-05-1.

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Facility and Equipment Conformance to Updated Final Safety Analysis Report (UFSAR) Description (71707, 37551)

A recent discovery of a licensee operating a facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and parameters. No anomalies between the UFSAR and operation of the facility were identified.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Open) IFI 50-416/96003-01: review long-term justification for methodology and assumed valve factors. This item identified the need for the licensee to provide additional justification for the group valve factors assigned to two MOV groups: the 150-pound Powell Gate Valve GA1 Group (which was assigned a 0.62 valve factor) and the 600/900-pound Powell Gate Valve GA1 Group (which was assigned a 0.50 valve factor). This item also included a concern that the licensee's contractor (Siemens, Inc.) had not adequately demonstrated that their analysis methodology could predict the onset of major valve damage (the capability to predict minor damage had been acceptably demonstrated).

The licensee stated that it intended to dynamically test two additional valves in each of the two groups in question to provide additional support for the assigned group valve factors. The inspectors considered this to be a reasonable response to the concern, assuming that the test results from this testing are consistent with the existing analysis. If not, additional testing would be warranted. The licensee stated that testing of the four valves would be completed prior to startup from the next refueling outage (RFO9).

Regarding the capability of the contractor's methodology to predict the onset of major valve damage, the inspectors reviewed a paper developed by the contractor addressing this question. The paper showed test results of a 6-inch 900-pound Anchor Darling valve that displayed high contact stresses between the disc and seat under blowdown conditions, indicative of major damage, and compared these results to a similar test of a Powell valve. Based on similarities in disc geometry, the contractor concluded that major damage of the Powell valves, if it had occurred, would have been detectable. The inspectors considered this information to resolve the concern.

This item will remain open pending NRC review of the additional tests discussed above.

E8.2 (Closed) IFI 50-416/96003-02: review RCIC valve enhancements to increase margin. RCIC Valves E51F0063 and E51F0064 (drywell inboard and outboard isolation valves in steam supply to RCIC turbine) were marginal in their closing capability, requiring a reduction in the group valve factor (from 0.50 to 0.36) or taking credit for torque switch bypass to demonstrate operability. The licensee committed to restore margin to these valves prior to startup from the RFO8.

The licensee performed a control circuit modification on both valves, removing the torque switch from the circuit and allowing the valve to close on the limit switch. Calibrated compensator springpacks were installed on both valves, which then were used to set the limit switch within a specified closing thrust range. To provide additional motor actuator torque capability, the licensee modified the motor gearset to provide an increase in the overall gear ratio.

The licensee raised the valve factor for these two valves from 0.36 to 0.45, which was consistent with the testing (of an identical valve) performed by the Idaho National Engineering Laboratory. The resulting as-left margins were 16.2 percent for E51F063 and 21.9 percent for E51F064, based on the thrust measured at limit switch trip. Higher margins would have resulted if the licensee had taken credit for the degraded voltage capability of the motor actuator. Both valves would have had positive margin even if the group valve factor of 0.5 had been used.

The inspectors concluded that the licensee had acceptably addressed this concern.

E8.3 (Closed) IFI 50-416/96003-03: worm pitch deviated from nominal value. The licensee had used a measured worm pitch (0.150 inches) that deviated significantly from the manufacturer's (Limitorque) published nominal value (0.187) for Valve B21F016, inboard main steamline drain isolation, and was relying on this information for the demonstrated operability of this valve.

In response to this item, the licensee remeasured the worm pitch of Valve B21F016 and found it to be almost exactly 0.187 inches, as published by Limitorque. The licensee initiated CR 1996-0578. There were no other measurements of worm pitch that deviated significantly from Limitorque's specifications, and no other valves were relying on worm pitch measurements for operability. Therefore, a generic concern did not exist.

The remaining question was whether Valve B21F016 was operable in the as-found condition. Using the measured worm pitch, the corrected as-left torque switch trip torque was 90.44 foot-pounds. This was greater than the torque limit of 74 foot-pounds based on the degraded voltage and temperature adjusted torque capacity of the valve. Therefore, the concern would be that the valve could stall in an attempt to close under design conditions. The licensee made two adjustments to the calculations to show operability. First, the temperature derating was decreased from 330°F. The valve is located in the drywell with a preaccident temperature of 135°F and a maximum postaccident (steamline break in drywell) temperature of 330°F. Although the drywell heatup takes place almost instantaneously, Valve B21F016 would stroke within 20 seconds on a Group 1 isolation. Based on the short heatup time available, the licensee calculated that a temperature of 210°F would be appropriate for derating the torque output of the motor. This raised the torque capability of the valve to 86.9 foot-pounds, still slightly less than the as-left torque switch trip torque of 90.44 foot-pounds. The licensee's second calculational adjustment was to use the actual torque switch repeatability (calculated from repeated test results) in place of the value published by Limitorque. Using the lower, measured repeatability value resulted in an as-left torque switch trip torque of 86.6 foot-pounds. Since this was less than the torque capability of the valve (86.9 foot-pounds), the licensee considered Valve B21F016 to have been operable.

The inspectors agreed with the licensee's determination of past operability and concluded that the licensee had adequately resolved this issue.

The inspectors concluded that the licensee had adequately resolved this concern.

E8.4 (Closed) IFI 50-416/96015-01: review of unexpected drop in MOV closing torque and potential implications. The as-found thrust value for Low Pressure Core Spray Valve E21F012, test return isolation, decreased significantly from the previous as-left test to less than the calculated minimum required thrust. This low thrust created a concern for the past operability of this valve and the validity of VOTES test results throughout the safety-related MOV population.

The licensee thoroughly inspected the actuator of Valve E21F012 and reviewed the VOTES diagnostic test information. Though no root cause was determined, the licensee identified two possible reasons for the unexpected change in delivered thrust: (1) an undetectable error was made in the original VOTES test, such as placing the calibrator clamp in the wrong position, or (2) because an extra amount of gasket material which could impact worm gear alignment was found and because two sets of scuff marks were evident on the worm gear. The worm to worm gear interface may have been loose allowing for widely varying changes in torque to thrust conversion efficiency. Either of these causes, or both in combination, could explain the observed anomaly. The inspectors considered neither to constitute a generic concern because, according to the licensee, within the scope of all retested MOVs at Grand Gulf (100+), there were no other instances where delivered thrust decreased to such a significant degree.

Within CR 1996-0047, the licensee evaluated the as-found condition of Valve E21F012 and concluded this valve was operable despite the thrust loss. This position was based on evidence that the valve successfully closed during quarterly inservice testing strokes conducted during the period in question. Valve E21F012 is a primary containment isolation valve. The piping outboard of the valve was maintained pressurized (above reactor coolant system pressure) by a jockey pump. If this pressure differential is lost, a control room annunciator sounds. The plant staff did not recall this annunciator sounding during the period in question. Consequently, the licensee concluded that the valve had successfully closed during testing despite the apparent underthrust condition. Also, the valve was VOTES tested at greater than the maximum expected differential pressure after the torque switch had been set (early in the period of concern) and had stroked successfully under these conditions. Based on this information, the inspectors concluded that the valve could have performed its design function despite the lower-than-desired torque switch setting.

The inspectors concluded that the licensee had acceptably resolved the issues associated with this event.

IV. Plant Support

P3 Emergency Preparedness Procedures and Documentation

P3.1 Licensee Onshift Dose Assessment Capabilities (Temporary Instruction (TI) 2515/134)

a. Inspection Scope

Using TI 2515/134, the inspectors gathered information regarding:

- Dose assessment commitment in emergency plan
- Onshift dose assessment emergency plan implementing procedure
- Onshift dose assessment training.

The inspectors reviewed the following emergency plan and implementing procedures:

- 10-5-01-1, "Activation of the Emergency Plan," Revision 100
- 10-5-01-12, "Radiological Assessment and Protective Action Recommendation," Revision 21
- Grand Gulf Nuclear Station Emergency Plan, Revision 23.

b. Observations and Findings

On December 17, 1996, the inspectors conducted an inoffice review of the emergency plan and implementing procedures to obtain the information requested by the TI. The inspectors also conducted a telephone interview with the licensee on December 17, 1996, to verify the results of the review. Based on the documentation review and licensee interview, the inspectors determined that the licensee had the capability to perform onshift dose assessments using real-time effluent monitor and meteorological data; however, the commitment was not clearly described in the emergency plan and implementing procedures.

c. Conclusion

The licensee had the capability to perform onshift dose assessments using real-time effluent monitor and meteorological data.

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (71750)

a. Inspection Scope

Using Inspection Procedure 71750, the inspectors made frequent tours of the radiological controlled areas and observed radiological postings and worker adherence to protective clothing requirements.

b. Observations and Findings

In general, the inspectors found that areas were properly posted and secured with the exception of a locked high radiation area light located in the RCIC pump room which was not illuminated. The inspectors notified health physics personnel and the light was immediately restored. The inspectors verified that health physics personnel were performing daily rounds for the locked high radiation area lights and that this light was checked for proper operation within the allowed time frame. During one routine tour, the inspectors noted that radiation survey maps for various areas were not properly updated. The inspectors contacted health physics personnel and the survey postings were updated. The inspectors questioned health physics personnel and radiation protection management personnel concerning the posting requirement for survey maps. The licensee responded that the applicable survey maps should have been posted, in accordance with a standing order (management expectation), by health physics personnel at the time the surveys were performed. The licensee initiated CR 1996-0594 to address this issue.

c. Conclusion

In general, radiological areas were properly posted, personnel were following radiation work permit requirements and displayed good radiation worker practices. Health physics technicians were knowledgeable of current plant radiological conditions. However, survey maps displaying current radiological conditions were not properly updated for several radiation areas.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on December 23, 1996. The licensee acknowledged the findings presented. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

C. Bottemiller, Superintendent, Plant Licensing
L. Daughtery, Technical Coordinator, Plant Licensing
W. Deck, Superintendent, Security
R. Dubey, Technical Assistant, Nuclear Plant Engineering
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R. Moomaw, Manager, Plant Maintenance
C. Smith, Manager, Planning and Scheduling
C. Stafford, Operations Assistant, Plant Operations

NRC

J. Donahew, NRR Project Manager

INSPECTION PROCEDURES USED

37551	Onsite Engineering
40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
61726	Surveillance Observations
62707	Maintenance Observation
71707	Plant Operations
71750	Plant Support Activities
92902	Followup - Maintenance
92903	Followup - Engineering
93702	Prompt Onsite Response to Events At Operating Power Reactors
TI 2515/134	Licensee On-Shift Dose Assessment Capabilities

ITEMS OPENED, CLOSED, AND DISCUSSED

Closed

50-416/95012-02	IFI	Followup on the licensee's activities to replace worn parts on the RCIC pump mechanical overspeed trip device and to revise preventive maintenance procedures (Section M8)
50-416/96003-02	IFI	Review RCIC valve enhancements to increase margin (Section E8.2)
50-416/96003-03	IFI	Worm pitch deviated from nominal value (Section E8.3)
50-416/96015-01	IFI	Review of unexpected drop in MOV closing torque and potential implications (Section E8.4)

Discussed

50-416/96003-01	IFI	Review long-term justification for methodology and assumed valve factors (Section E8.1)

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
CARB	Corrective Action Review Board
CR	Condition Report
CRD	Control Rod Drive
CST	Condensate Storage Tank
IFI	Inspection Followup Item
MOV	Motor Operated Valve
NRC	Nuclear Regulatory Commission
RHR	Residual Heat Removal
RCIC	Reactor Core Isolation Cooling System
RFO	Refueling Outage
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report