U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No:	50-302
License No:	DPR-72
Report No:	50-302/99-06
Licensee:	Florida Power Corporation
Facility:	Crystal River 3 Nuclear Station
Location:	15760 West Power Line Street Crystal River, FL 34428-6708
Dates:	August 15 through September 25, 1999
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Enclosure

EXECUTIVE SUMMARY

Crystal River 3 Nuclear Station
NRC Inspection Report 50-302/99-06

This integrated inspection includes aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection. In addition, it includes the results of announced inspections by regional reactor inspectors in the areas of Emergency Operations Procedures and Engineering, as well as visiting resident inspectors for the Corrective Action Program inspection.

Operations

- Full withdrawal of axial power shaping rods at end of core life was well controlled. Briefings were thorough and covered expected indications. Operators closely monitored all reactivity changes. A formal Operations program required reactor engineering guidance to operators to be written and approved by Operations management. Operations management control of information and guidance from other groups to the operating crews has significantly improved (Section O1.2).

- Preparations for Hurricane Floyd were very challenging due to the extensive amount of material staged for a pending refueling outage and ongoing construction of a new emergency feed pump facility. The licensee efforts were pro-active and resulted in the site being very well prepared for the possibility of a hurricane strike (Section O1.3).

- A non-cited violation was identified for two examples of failure to fulfill clearance tagging program requirements. Electrical work was performed on a nitrogen heater with a closed 480 volt line breaker that was tagged open. Electricians did not discuss an unexpected energized status light with supervision and consequently did not identify the incorrect breaker position. In another example, active red tags were removed from electrical control panel switches. Training of contract workers did not explicitly ensure that red tags and components were not to be removed or manipulated. Although a definitive cause was not found for either event, the licensee investigations were prompt and comprehensive (Section O4.1).

- The licensee's corrective action program, including problem identification and resolution, use of operating experience, self-assessment activities, safety review committees, and use of risk insights, was well understood and supported by management, appeared to be effective, and was functioning well. Improvements were identified in corrective action backlog and prioritization management, and in self-assessment implementation effectiveness (Sections O7.1-O7.8).

- Licensee Quality Assurance audit activities were broad and indicative of detailed questioning and familiarity with applicable standards and requirements. A licensee self-assessment on commitment tracking was thorough and indicated the licensee was effectively tracking outage commitments (Section O7.9).

Maintenance

- Performance of maintenance activities remained effective. Troubleshooting for the cause of a B Emergency Diesel Generator trip was controlled and systematic. All of the plant indications received on the trip were rigorously researched to ensure the causes were understood and corrected (Section M1.1).

- Inspectors identified that flow transmitters inside a hydrostatic test boundary had not been vented. Damage could have occurred due to isolation valve leakage. Licensee hydrostatic test guidance was not referenced when preparing and approving the test clearance. Operators were not familiar with guidelines for hydrostatic testing clearances (Section M1.2).

- Completed surveillance test packages demonstrated acceptable test results for emergency core cooling system relief valves and check valves (Section M1.3).

- Review of valve seat leakage testing data indicated acceptable material condition for reactor coolant system isolation boundaries. No examples of inadequate maintenance or testing were identified during this review. No problems were identified during the review of machinery history which would indicate an adverse trend or degradation of the material condition of reactor coolant system pressure isolation valves. Monitoring associated with identified reactor coolant system leakage was acceptable (Section M2.1).

- A non-cited violation was identified involving a failure to perform additional testing of relief valves after testing identified the valves did not lift at setpoints, as required by ASME/ANSI OM-1987, Part 1 and maintenance procedures (Section M2.2).

Engineering

- Initial inspection of design change packages for the emergency feedwater system, the high pressure injection system, and the low pressure injection system found that the concept of the changes would fulfill the design objective, the design control process in general was adequate, and the details reviewed were correct (Section E1.2).

- Implementation of controls to minimize primary coolant leakage sources outside containment were effective. Calculations and surveillance limits were conservative and licensee program commitments were fulfilled. Justification to exclude seal ring leakage from a makeup system isolation valve was appropriate. Recent improvements to the program included specific testing of makeup system piping for leakage and more pro-active leakage monitoring (Section E2.1).

Report Details

Summary of Plant Status

The plant operated at full rated thermal power throughout the report period.

I. Operations

O1 Conduct of Operations

O1.1 Routine Conduct of Operations Reviews (71707)

Resident inspectors performed routine reviews of plant operations, including shift turnovers, operator narrative logs, and clearance tags. Inspectors toured safety-related areas to observe the physical condition of plant equipment and structures and verified the alignment and operability of selected, risk significant safety systems. Inspectors also accompanied Auxiliary Building and Turbine operators on daily rounds and observed daily meetings and control room activities. Noteworthy observations are discussed in subsequent paragraphs.

The inspectors observed instances of unsecured work boxes and equipment and potential blockages of operating components due to the large amount of material being staged for the refueling outage. While no individual safety-significant problems were identified, controls over the large volume of material were questioned. Licensee management appropriately addressed the trend.

The inspectors observed good conduct of Operations throughout the report period. Non-licensed building operators performed thorough tours, were familiar with the status of equipment in their areas, and took accurate logs. Control room operators continued to closely monitor plant parameters and communicate effectively. No findings were identified with operator control and awareness of plant evolutions.

O1.2 Axial Power Shaping Rod (APSR) Withdrawal and Interface with Reactor Engineering

a. Inspection Scope (71707)

From August 24 through August 28, operators fully withdrew the APSR assemblies from the reactor core. Inspectors observed some of the iterative withdrawals and verified Technical Specification (TS) and Core Operating Limits Report (COLR) restrictions were fulfilled.

b. Observations and Findings

The inspectors observed that thorough briefings were conducted prior to the APSR withdrawals and operators closely monitored for expected reactivity changes on each withdrawal. Reactor engineering coverage was thorough, with an engineer in the control room for all observed withdrawals. TS 3.2.2.1 and COLR limits required APSRs to be fully withdrawn between 640 and 660 effective-full-power-days (EFPD) and not reinserted. The inspectors verified full withdrawal was completed at 645 EFPD and the

APSRs were prevented from reinserting by tagging the power supply breakers off. Operators withdrew the APSRs in accordance with a specific Operations Procedure (OP). Inspectors verified that appropriate procedural prerequisites and limits were fulfilled and observed that operators were also adhering to more detailed written guidance from reactor engineering. While much of this guidance previously would have been provided verbally by reactor engineers, Operations had recently implemented a Reactor Operation Communication Sheet (ROCS) program to formalize this guidance. It required formal written instructions as well as approval by a member of Operations management. The licensee used the program for Chemistry operational guidance and was planning to expand the program to other engineering groups. The ROCS entry for APSR withdrawal was clear, within the OP limitations, and contained beneficial information for expected plant response. A second ROCS entry on use of de-borating demineralizers was similar in quality. The inspectors considered the new program increased the amount of pre-planning for evolutions impacting reactivity and was an improvement over the previous verbal method. This was a continuation of an improving Operations trend to control and ensure management approval of guidance from other sources to operators.

c. Conclusions

Full withdrawal of axial power shaping rods at end of core life was well controlled. Briefings were thorough and covered expected indications. Operators closely monitored all reactivity changes. A new Operations program required reactor engineering guidance to operators to be written and approved by Operations management. Operations management control of information and guidance from other groups to the operating crews has significantly improved

O1.3 Hurricane Floyd and Tropical Storm Harvey Preparations (71707, 71750)

On September 13, the licensee initiated Emergency Plan Procedure EM-220, Violent Weather, in anticipation of impact from Hurricane Floyd. Preparations to store and secure equipment were very challenging given the extensive amount of material staged for the pending refueling outage and the ongoing construction of a new emergency feed pump building and piping. The inspectors observed that the licensee methodically categorized the material and equipment that needed to be addressed and had management prioritize limited resources. Appropriate high priority was placed on removing recently delivered new reactor fuel from shipping canisters into the new fuel pit and maximizing electrical switchyard and emergency equipment capability. The inspectors observed that the licensee's pro-active efforts resulted in the prioritized items being completed before the expected arrival of hurricane force winds. The inspectors did not identify any noteworthy concerns with the licensee preparations except with a problem involving replacement of the spent fuel (SF) pool missile shields. Maintenance personnel had difficulty aligning the last of the missile shields. One shield's screw holes had to be retapped and the very last shield could not be replaced altogether because of SF bridge storage issues. Prior to the hurricane preparations, the SF bridge was being used to transfer new fuel from dry to wet storage and was stowed for short term instead of long term storage. The problem was corrected prior to the preparations for Tropical

Storm Harvey. The overall preparations for Harvey were not as encompassing because most of the preparations for Floyd were still in place.

O2 Operational Status of Facilities and Equipment

O2.1 Makeup Valve MUV-31 Fails Full Open (71707)

On the afternoon of September 24, 1999, the main control room received a high pressurizer level alarm. The control board operators noted increasing pressurizer level and reactor coolant system pressure. In addition, the operators noted makeup tank level decreasing and normal makeup flow significantly elevated (approximately 140 gallons per minute (gpm)); however, the makeup flow high alarm was not received. The operators determined the makeup flow control valve (MUV-31) had failed open and immediately isolated normal makeup and letdown by closing the makeup line isolation valve (MUV-27) and the letdown block orifice inlet isolation valve (MUV-50). Pressurizer level was manually controlled with the block orifice bypass flow control valve and MUV-31 was manually isolated by closing its inlet isolation valve. No Technical Specifications were applicable for this failure. Subsequently, the licensee determined that the makeup high flow alarm setpoint was set at greater than 160 gpm flow through MUV-31, but the maximum achievable flow is between 135 and 140 gpm. Precursor Card (PC) 99-3155 was written to resolve this discrepancy, and Operations promptly established an operator programmable annunciator alarm for makeup flow (set at less than 100 gpm). Maintenance troubleshooting determined that the voltage-current converter for MUV-31 control circuitry had failed so it was replaced. The inspectors considered the operators' actions prompt and appropriate, and the maintenance activities responsive and effective.

O4 Operator Knowledge and Performance

O4.1 Clearance Tagging Problems

a. Inspection Scope (71707)

The licensee continued to identify clearance tag problems during this report period. Clearance problems were previously discussed in Inspection Report 50-302/99-05. A breaker tagged open to support maintenance work was found closed and active clearance tags were found removed from an electrical panel. Inspectors reviewed the details of each event and the licensee's response.

b. Observations and Findings

On August 25, operators clearing tags following preventive maintenance to a nitrogen supply heater found the 480 volt heater supply breaker ON although it was tagged OFF. The licensee immediately initiated an event investigation under PC 99-2784. An audit of all active hanging clearances and third party checks of all clearance tagging activities was initiated due to the unknown cause of the incorrect breaker position. The investigation noted that electricians had identified an illuminated 120 volt indicating light on the heater panel. After reviewing electrical prints, they verified the 120 volt heater

control power breaker was tagged open and locally checked the heater element de-energized. They commenced work and attributed the light to a note in their work package regarding an energized cabinet space heater. They did not check the 480 volt supply breaker. The light was powered from the 480 volt supply breaker which was in the ON position when the work was being performed. An open nitrogen flow switch contact was the only interruption of 480 volt power to the heater during the work. The licensee had each operator who hung and verified the tag independently recreate their physical actions at the breaker panel. They noted the breaker position was obvious and did not have to be repositioned since it was the only panel breaker normally in the OFF position. Consequently, the licensee was unable to determine a definitive root cause for the open breaker. However, the investigation was thorough and addressed possible inadvertent breaker operation by contract workers. Broad corrective actions were identified. The inspectors noted that the maintenance electricians assumed the reason for the unexpected energized light and did not discuss it with supervision.

In the second example, a contractor supervisor found six active red tags removed from a new air compressor electrical panel on September 14. The licensee again initiated an immediate investigation under PC 99-3011. The new panel switches did not have secure tag mounting holes so the tags were loosely affixed with tie-wraps and tape. Since the electrical panel switch covers had recently been installed, the licensee postulated that a worker had removed the tags to install the covers over the tight clearances of the switches. The licensee was unable to verify this course of events. They identified several possible contributing causes, including worker unfamiliarity with the plant tagging process. The inspectors determined that the licensee relied on general worker knowledge of basic red danger tag principles. Consequently, training received by contract workers did not explicitly state that red tagged components were not to be manipulated or to be removed by personnel other than operators.

The inspectors determined the licensee written clearance program remains effective if followed. However, these significant examples of failures to follow the clearance process are violations of regulatory requirements for procedural implementation. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Appendix C of the NRC Enforcement Policy, and will be referenced as NCV 50-302/99-06-01, Two Examples of Failure to Fulfill Clearance Process Requirements. This violation is in the licensee's corrective action program under PCs 99-2784 and 3011.

c. Conclusions

A Non-Cited Violation was identified for two examples of failure to fulfill clearance tagging program requirements. Electrical work was performed on a nitrogen heater with a closed 480 volt line breaker that was tagged open. Electricians did not discuss an unexpected energized status light with supervision and consequently did not identify the incorrect breaker position. In another example, active red tags were removed from electrical control panel switches. Training of contract workers did not explicitly ensure that red tags and components were not to be removed or manipulated. Although a definitive cause was not found for either event, the licensee investigations were prompt and comprehensive.

O7 Quality Assurance in Operations

O7.1 Corrective Actions, Corrective Action Program, and Related Processes (40500)

The inspectors reviewed the licensee's Corrective Action Program (CAP) and processes as delineated in compliance procedures CP-111, 111A, and 111B, titled, respectively, Processing of Precursor Cards for Corrective Action Program, Precursor Card Screening Activities and Changing Grading Guidance, and Condition Resolution and Evaluation. In addition, various user implementation manuals were reviewed. This included a performance-based real time review of problem identification for ongoing issues and CAP document development. The inspectors also reviewed a selection of PCs, corrective actions (CAs) completed and pending, the Management Review Committee (MRC) and Corrective Action Review Board (CARB) processes, Nuclear Safety Assessment Team (NSAT) and Shift Technical Advisor (STA) involvement, PC and CA backlogs, and the threshold for initiating PCs. Recent NRC performance reviews and performance indicators were reviewed by the inspectors.

The inspectors concluded that the CAP was appropriately functioning, was well understood and implemented by site personnel, received strong support from management, and had a very low threshold for initiation. The STA, MRC, and NSAT processes were effective in timely screening and prioritization of problems. However, minor implementation issues were identified with the process including the initiator and supervisor performing the same PC sign off, and some missing PC fields and comments. These issues did not detract from CAP effectiveness and were not violations of regulatory requirements. The inspectors noted that the current open corrective action backlog at the time of this inspection was about 1500 items which included 150 items for level "B" PCs (more significant). Although these open items were not prioritized by risk significance, the inspectors concluded that these open actions did not impact current plant operation. Although the low threshold for PC implementation was commendable, a large backlog with a high PC generation rate could potentially mask or hide issues or corrective actions necessary to deal with significant problems. The inspectors did not find any evidence of this and management was cognizant of this vulnerability.

O7.2 Resolution of Problems (40500)

The inspectors reviewed the licensee's process for resolving problems identified in the PC process. This included a review of PC actions, root cause and apparent cause analyses, Employee Concerns Program (ECP) and NRC allegations, maintenance and repair activities, operations workarounds, temporary modifications, repetitive equipment failures and Maintenance Rule a(1) classifications, work order backlog, Quality Assurance (QA) audits and self assessments, and timeliness of corrective actions.

Selected root cause and apparent cause reports were reviewed and determined to be thorough and had adequately identified corrective actions. The CARB process effectively evaluated and assessed the identified problem causes and associated corrective actions. The ECP was staffed with qualified and dedicated personnel, was functioning well, and was supported by management. Rework, work order backlog, and

repetitive maintenance issues were adequately addressed. The number of open temporary modifications and operator workarounds was low and any plant effects had been evaluated. Selected operability evaluations were reviewed and determined to be adequate. Corrective actions from the PCs were identified and tracked to completion.

O7.3 Operating Experience Feedback (40500)

The inspectors reviewed the adequacy of the licensee's program to implement corrective actions for the Operating Experience Feedback (OEF) program. Administrative Instruction AI-404B, Review of Industry Operating Experience, provided appropriate guidance and requirements regarding the use of OEF. Several PCs were reviewed to verify that industry issues and lessons learned were properly researched and the appropriate personnel were informed to determine applicability and initiate corrective actions when required.

Proper OEF collection, screening, distribution, and development of corrective actions were observed in accordance with procedural requirements. Additionally, the inspectors verified that the licensee was using OEF for Maintenance Rule applications when developing goals and monitoring criteria and when completing periodic evaluations for structures, systems, and components. The inspectors concluded that the OEF program was functioning well.

O7.4 Self-Assessment Activities (40500)

The inspectors reviewed the licensee's self-assessment process, including implementation, effectiveness, CAs and follow up, and reviewed several self-assessment and quality assessment reports. The inspectors verified that PCs were written for all weaknesses and areas for improvement in subsequent reports. Identified CAs were determined to be adequate, properly prioritized, and implemented appropriately. Reports were generally good with significant findings and observations noted.

Team leader training was adequate and provided a good basis for starting a self-assessment. Through interviews, the inspectors determined that the instruction and manual were useful for report formatting and writing, but not as a step-by-step procedure. The instruction was not a formal controlled procedure at the time of the inspection but the licensee had plans to issue it as one. Team leaders indicated that the self-assessment coordinator was available for questions and very helpful throughout the process. Management support during the conduct of assessments was determined to be adequate overall. There was some indication that team leaders, at times, found it difficult to obtain dedicated personnel (i.e., full time participation). Self-assessments were performed in all major functional areas and continue to evolve with the planned use of performance indicators, trending, and grading. The inspectors concluded that the self-assessment process was appropriately functioning with some noted comments.

O7.5 Onsite and Offsite Safety Review Committee Activities (40500)

The inspectors reviewed the onsite and offsite safety review committees, including the Plant Review Committee (PRC) and the Nuclear General Review Committee (NGRC). FSAR sections 12.8.1 and 12.8.2, and related implementing procedures were reviewed. Committee chairpersons and members were interviewed, and meeting minutes were reviewed. In addition, self assessments (CSRA 98-27 and 99-08) performed on the safety review committee processes were reviewed by the inspectors.

Based on current and previous NRC inspections and assessments, the inspectors concluded that both the onsite and offsite safety committees were functioning per the program requirements, with noted positive influence toward nuclear safety. Issues related to improvements in the process were self-identified, with appropriate PC initiation and subsequent closure, based on completed corrective actions.

O7.6 Corrective Actions for Non-Cited Violations (40500)

The inspectors reviewed corrective actions associated with selected NCVs. Root cause investigations were appropriate for the safety and risk significance of the issues involved. The corrective actions developed addressed the problems identified to restore compliance when necessary and prevent recurrence. For the NCVs reviewed, corrective actions were adequate and implemented effectively.

O7.7 Use of Risk Insights (40500)

The inspectors reviewed the use of risk insights as related to the corrective action program and other processes. The inspectors determined that the use of risk insights occurred on the front-end of the CA process when grading PCs. Risk insights were not used on the back-end to prioritize CAs. The inspectors determined that the self-assessment process was not specifically linked to the risk process. However, the licensee also identified and is planning to incorporate risk into the process (PC 99-2721). The inspectors determined that system outage risk assessments were being performed prior to beginning work on systems or components (i.e., on-line maintenance). The inspectors concluded that risk insights were adequately being utilized throughout most CA processes.

O7.8 Employee Interviews (40500)

The inspectors interviewed selected licensee employees to assess their knowledge, use of, and support for the CAP and self-assessment processes. Personnel interviewed included site and plant management, department heads, quality assurance and ECP personnel, CAP implementers, and plant workers, including operators, maintenance, and engineering personnel.

The inspectors noted a good understanding and knowledge of the CAP processes and appropriate implementation. Strong support of the CAP and self-assessment programs was noted at high levels of management.

O7.9 Licensee Self-Assessment Activities (71707)

Resident inspectors routinely reviewed various licensee self-assessment activities, including attending the exit meeting and reviewing the findings of Nuclear Quality Assessments' (NQA) Audit 99-07, Radiation Protection and Chemistry, and reviewing licensee self-assessment 99-12B, Refueling Outage 11 Commitment Review. The inspectors observed that the NQA audit scope was very broad, but detailed in certain areas. The audit inspections appeared performance-based. Several NQA findings were indicative of detailed questioning and familiarity with applicable standards and requirements. The licensee self-assessment on outage commitments was thorough in that it verified every outage-coded commitment. Although some discrepancies were noted by the licensee, the inspector concluded the licensee was effectively tracking outage commitments.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Violation 50-302/98-02-01: Inadequate Corrective Actions to Recently Identified Deficiencies Associated with Emergency Operating Procedure Actions. This violation consisted of two parts. The disposition of each of the parts is detailed below:

Violation 50-302/98-02-01 Part 1 - Failure of the corrective actions for PC3-C98-0103. During implementation of corrective actions for PC3-C98-103, the licensee failed to identify an additional error in AP-770 and errors in other APs. This part of violation 50-302/98-02-01 concerned development of EOP/AP labeling and validation that the labels matched the procedures. The inspector selected several local actions from EOP/AP's and verified the labeling on the local controls was correct. The inspector found no discrepancies in the location of the labeling or in the label's content. This item is closed.

Violation 50-302/98-02-01 Part 2 - Failure of the corrective actions to adequately evaluate the radiological mission dose associated with installing the Reactor Building purge flow instruments. The inspector reviewed the completed calculations associated with the Reactor Building purge mission dose and the assumptions. The calculation appeared complete and accurate. The level of detail in the calculation was supported by computer simulations and time motion simulations. The licensee reconfigured the staged equipment to assure the task could be performed with a minimum of exposure to the workers installing the Reactor Building purge equipment. The dose rates were below the 5 REM allowable. This item is closed.

O8.2 (Closed) Violation 50-302/98-02-09: Inadequate Piggyback Testing. Inspection report 50-302/98-02, identified that the licensee had sufficient data from component manufacturers to certify the High Pressure Injection pumps and related components for long term post-accident operation. However, while the licensee had adequate technical justification for operating in the piggyback mode, piggyback mode testing did not fully demonstrate satisfactory equipment performance. Of special concern were the LPI injection valves which would need to operate in a severely throttled condition. The valves were not designed for throttling and were not throttled during initial piggyback

testing. The inspector reviewed the licensee planned LPI/HPI system modifications scheduled for Refueling outage number 11 (R11). The plans included eliminating the need to throttle the LPI injection valves, significant piping and configuration changes. The licensee also intends to add additional throttle valves for establishing LPI/HPI piggyback injection and pressurizer spray flow. There are also full flow post modification tests planned which will be used to demonstrate the systems full capability. Any differences between the expected system operating characteristics will be evaluated for impact on EOPs, the simulator model, or plant procedures. The post modification test will be reviewed by NRC during R11. This item is closed.

O8.3 (Closed) Inspector follow-up Item 50-302/98-02-05: Consideration of Obstruction of In-Plant EOP Actions by Maintenance. This item involved the status of the corrective actions to incorporate procedural controls to evaluate whether maintenance activities could affect EOP in-plant actions. The inspector performed a walk-down of the auxiliary and intermediate buildings to determine the impact or pre-outage activities on EOP/AP equipment and controls. This included the prestaged equipment storage lockers and EOP designated ladders. The inspector also reviewed the work control process. All equipment was readily accessible and the procedures for ensuring the equipment accessibility were adequate. This item is closed.

O8.4 (Closed) Violation 50-302/97-12-02: Inadequate Corrective Actions. This violation consisted of two parts. The disposition of each of the parts is detailed below:

Violation 50-302/97-12-02 Part 1 - This item was associated with long term corrective actions. These included updating several calculations. The inspector selected M97-0136, SGTR Mission Dose, and M-93-0006 Post accident Operator Dose for Hydrogen Purge for review. The assumptions were appropriate and adequately were justified. The administrative procedures that were required to ensure that the plant was operated within the boundaries established by engineering assumptions in procedures were adequate. This item is closed.

Violation 50-302/97-12-02 Part 2 - This item was associated with short term corrective actions, primarily associated with the establishment and maintenance of a temperature envelope for the operation and calibration of instrumentation. This item involved reviewing the temperature controls for various areas of the plant and various EQ zones. The temperatures were then compared to the temperatures used for instrument calibration and loop uncertainty calculations. The inspector reviewed the records for temperatures monitored in various EQ zones and the corrective actions the licensee took when the temperatures were outside these bands. The inspector also reviewed the actions the licensee intends to take to ensure that the instrumentation stays within the environmental zones required for the equipment to be operable. These include maintaining the environmental control systems and adjusting loop uncertainty calculations to have a wider temperature tolerance. The inspector found the licensee's progress in this area was adequate. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Routine Observations (62707, 61726)

The inspectors observed various portions of several corrective maintenance tasks and surveillance tests, evaluated the scheduling and coordination of the work, and reviewed associated documentation. Maintenance tasks continued to be well controlled, accurately scheduled, and closely supervised. Activities observed included the emergent investigation of B train DC electrical grounds following a trip of the B emergency diesel generator (EDG) during routine surveillance testing on August 30. Indications observed on the trip included a failure of the emergency stop pushbutton and the loss of indications on a vital inverter. The troubleshooting task was complicated because more than 12 hours of the B EDG Technical Specification (TS) train emergency diesel 72-hour Limiting Condition for Operation (LCO) had already elapsed due to the routine testing. The inspectors observed that the licensee utilized their normal work planning process to develop a detailed troubleshooting plan, even with the time pressure due to the LCO. Engineering support for the troubleshooting was constant. The licensee efforts identified broken connector pins on wiring to the EDG governor. The licensee appropriately entered the problem in their corrective action system, identified possible causes, and considered the impact on the A train EDG. The inspectors also observed that the licensee systematically and thoroughly evaluated the cause for every indication received on the EDG trip prior to declaring the EDG operable. The inspectors concluded that performance of maintenance activities remained effective and that troubleshooting for the cause of the B EDG trip was controlled and systematic.

M1.2 Hydrostatic Testing of Modified Auxiliary Feedwater Piping

a. Inspection Scope (62707)

During hydrostatic testing of new check valves added to the Auxiliary Feedwater (AFW) system injection lines on August 9, the licensee experienced significant delays due to several coordination and control problems and initiated Precursor Card (PC) 99-2553. Consequently, the inspectors reviewed preparations, attended the pre-job briefing, and observed testing in progress for the licensee hydrostatic test of the opposite train AFW injection line on August 16.

b. Observations and Findings

The inspectors observed that significant management attention had been directed on the testing project following the initial problems on August 9. The Project Manager for the test had been required to brief numerous managers on the coordination problems and the corrective actions implemented to prevent recurrence. During the pre-job briefing, the inspectors observed a management representative assigned to monitor the briefing add significant value by summarizing the potential risks of hydrostatic testing and emphasizing personnel safety. However, the scope of the pre-job brief was not well

structured in that it was lengthy and repetitive and did not cover a few important aspects of the test. A backup means of overpressure relief, which specifically was the pump operator, was not discussed and the operator was not familiar with expectations for his role. Numerous parameters that could require the test to be aborted were vaguely discussed for consideration for test termination, but clear abort criteria were not specified.

The inspectors reviewed the valve line-up and clearance for the test and noted that both AFW header flow transmitters (FT) inside the test boundary were isolated only by red-tagging their root valves closed and were not vented. Leakage by a root valve seat could potentially over-pressurize one side of the differential pressure cell and over-range the FT. The inspectors verified that a post-maintenance FT operability test was not planned, so leakage could have caused a latent failure. The inspectors raised the concern to Operations, who stopped the test and directed the FTs be vented. The inspectors subsequently determined that the FT root valves had not been included on the original clearance and were only added as an addendum on the day of the test. The originally requested clearance boundary given to Operations by Projects was minimal and only included main boundary valves on a marked-up print. A detailed tag request sheet that would have referenced hydrostatic test guidance was not completed. The clearance was prepared and reviewed by two individuals and also required Nuclear Shift Manager (NSM) approval (for a high energy system without double valve isolation). None of these reviews caused Operations to review the guidance that could have prompted them to isolate and vent the FTs. The inspectors also determined that the test Project Manager had inappropriately accepted a verbal concurrence from a non-licensed operator as adequate Operations approval for leaving FTs unvented. The licensee initiated PC 99-2646 in their corrective action system to address the problems.

The licensee implemented training for all operators on the unique tagging requirements for hydrostatic testing. The licensee also initiated editorial changes to clarify the maintenance procedure requirements and to increase Operations' oversight of testing. The licensee also verified the FTs were operable following all testing. The inspectors considered the licensee actions adequate to prevent recurrence. No regulatory requirements were violated.

c. Conclusions

Inspectors identified that flow transmitters inside a hydrostatic test boundary had not been vented. Damage could have occurred due to isolation valve leakage. Licensee hydrostatic test guidance was not referenced when preparing and approving the test clearance. Operators were not familiar with guidelines for hydrostatic testing clearances.

M1.3 Review of Maintenance and Test Packages for Emergency Core Cooling System (ECCS) Components

a. Inspection Scope (61726)

The inspectors verified that completed Surveillance Procedure (SP) test packages involving ECCS check valves and relief valves satisfied the applicable requirements including referenced TS surveillance requirements.

b. Observations and Findings

The inspectors reviewed test package documentation for recent performances of the following maintenance and surveillance testing activities:

- SP-602, "ASME Section XI Relief Valve Testing"
- SP-603, "DH/CF Check Valve Leak Testing"
- SP-929, "HPI and RCP Seal Injection Check Valve Closure Testing"

No problems were identified. All stated testing requirements including TS surveillance requirements had been satisfied. Completed test packages demonstrated acceptable test results.

c. Conclusions

Completed surveillance test packages demonstrated acceptable test results for emergency core cooling system relief valves and check valves.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Maintenance/Material Condition of Reactor Coolant System (RCS) Pressure Isolation Valves

a. Inspection Scope (62700)

The inspectors reviewed the licensee's program for maintenance and testing of RCS pressure isolation valves (PIVs) to determine the adequacy of that program for maintaining the integrity of RCS isolation boundaries. The inspectors also verified that the licensee's program for periodic leak rate testing of selected isolation valves satisfied Technical Specification (TS) 3.4.12.c, 3.4.13 and 3.4.13.1 requirements for RCS operational leakage and verification of RCS PIV leakage.

b. Observations and Findings

The inspectors reviewed machinery history and leak testing data for selected RCS PIVs to evaluate the adequacy of the program for maintaining the integrity of those RCS

isolation boundaries and to verify that TS 3.4.12.c, 3.4.13 and 3.4.13.1 requirements had been satisfied. Valves selected for review consisted of isolation valves, including check valves, which if failed could result in an interfacing system loss of coolant accident (ISLOCA). Systems selected for review included makeup/high pressure injection (MU/HPI), core flood (CF), and decay heat removal (DH) systems. The inspectors reviewed the surveillance procedures for periodic leak rate testing of PIVs and as-found leakage test data for selected valves from testing performed during the two most recent refueling outages. Specific leakage test packages reviewed are listed in Section M1.3. The inspectors also reviewed selected maintenance procedures used by the licensee for testing and inspection of check valves as required by the inservice testing (IST) program.

The inspectors noted that each of the leakage testing procedures required that a corrected value for valve leakage be calculated for the normal operating differential pressure associated with each PIV. This corrected leakage value was required to be used rather than the actual observed leakage values anytime testing involved a lower test pressure. This method was consistent with guidelines from American Society of Mechanical Engineers/American National Standards Institute (ASME/ANSI) OM-1987, Part 10, "Requirements for Inservice Testing of Valves in Light Water Power Plants" and NUREG 1482, "Guidelines for Inservice Testing at Nuclear Power Plants".

The licensee has not experienced any significant problems with operational backleakage from RCS PIVs. There was no evidence of problems associated with operational backleakage such as inadvertent pressurization of low pressure piping in ECCS systems. The inspectors noted that the licensee had been experiencing problems during this cycle with external leakage from two PIVs. These valves, DHV-3 and CFV-6, had minor seal ring leakage into the containment. Additionally, MU-27, Normal Makeup Valve, which is not considered a PIV, had experienced minor leakage outside containment. Repairs for each of these leaks was scheduled during the upcoming refueling outage. The licensee had quantified the leakage from each of these valves and had considered this leakage with identified leakage calculations performed in accordance with TS 3.4.12.c. The licensee had continued to trend this leakage which remained well below the TS 3.4.12.c limit of 10 gpm. Based on existing data at the time of the inspection, projected RCS leakage was not expected to exceed 1.38 gpm prior to start of the upcoming refueling outage.

The inspectors verified that the program for maintenance and testing of PIVs satisfied the TS requirements. The inspectors determined that no as-found valve seat leakage testing failures of RCS PIVs had occurred during the previous two refueling outages. No examples of inadequate maintenance or testing were identified during the review. No problems were identified during the review of machinery history which would indicate adverse trends or degradation of material condition of any RCS PIVs. The inspectors concluded that monitoring associated with identified RCS leakage from DHV-3, CFV-6, and MU-27 was acceptable and the licensee's decision to continue operating with known external leakage was reasonable.

c. Conclusions

Review of valve seat leakage testing data indicated acceptable material condition for reactor coolant system isolation boundaries. No examples of inadequate maintenance or testing were identified during this review. No problems were identified during the review of machinery history which would indicate an adverse trend or degradation of the material condition of reactor coolant system pressure isolation valves. Monitoring associated with identified reactor coolant system leakage was acceptable.

M2.2 Testing of ASME Section XI Class 2 and 3 Relief Valves

a. Inspection Scope (62700)

The inspectors reviewed results of lift setpoint testing of ASME Class 2 and 3 relief valves in the MU/HPI, CF, and DH systems which was performed during the last two refueling (RF) outages. Verification of correct lift setpoints for these relief valves was necessary to ensure proper operation of Emergency Core Cooling System (ECCS) systems. Additionally, the inspectors reviewed corrective actions for as-found failures on relief valves and verified established relief valve setpoints were proper for piping design pressure values.

b. Observations and Findings

The inspectors reviewed documentation for selected ASME Class 2 and 3 relief valves in these three systems that had been tested during the last two refueling outages. Specific relief valve test instructions reviewed were documented in Section M1.3. Some as-found lift setpoint failures had occurred for relief valves during this period but, in each case, lift setpoints had been readjusted whenever the as-found setpoint exceeded +/- 3% of nominal as required by ASME/ANSI OM-1987, Part 1, "Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices." The inspectors reviewed documentation for resetting lift setpoints for selected relief valves which had out-of-tolerance as-found lift setpoints. The inspectors compared lift setpoints from test procedures to plant drawings and design documents to verify that established relief valve setpoints were proper for piping design pressure values. Additionally, the inspectors reviewed maintenance work packages and post maintenance test documentation for completed work on selected relief valves. During this review the inspectors identified two relief valves with as-found lift setpoint failures where the licensee had failed to expanded the sample size as required by ASME/ANSI OM-1987, Part 1. Section 1.3.4 of ASME/ANSI OM-1987, Part 1, required that for each out-of-tolerance as-found lift setpoint that testing be performed on additional relief valves of the same type and manufacture. Sample expansion was also required by SP - 602, "ASME Section XI Relief Valve Testing", Section 5.2.1.3. The relief valves in question, MUV-61 and MUV-67, had been tested during Refueling Outage 9 (R9) in 1994. The licensee issued Precursor Card (PC) Report 3-C99-2894 to document this issue. During the subsequent review the licensee identified one additional relief valve, DRV-38, which had been tested during the above time period and had an as-found lift setpoint failure without the required expanded sample size. No other examples of failure to perform required additional

testing of relief valves were identified during the inspectors' review of test results for relief valve testing performed after 1994. The licensee's root cause determination concluded that these three failures to perform required sample expansion resulted due to personnel errors by the previous testing program manager. Technical Specification 5.6.1.1 requires that written procedures be established, implemented, and maintained for the activities recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. This includes surveillance and testing procedures, such as SP-602. Since the setpoint for those relief valves which had experienced as-found failures were readjusted as required and no recent examples of failure to test additional relief valves were identified, this problem was of low safety significance. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PC 3-C99-2894. This item is identified as NCV 50-302/99-06-02, Failure to Expand Sample for ASME Class 2 and 3 Relief Valves.

The inspectors noted that the licensee's program for testing ASME Section XI Class 2 and 3 relief valves included only those relief valves which had an accident mitigation function. The inspectors noted that testing of ASME Class 2 and 3 relief valves located in the letdown and purification portions of the MU/HPI system, was not included in the scope of the IST program. Additionally, those relief valves were not required to be tested by the licensee's preventive maintenance program. The inspectors were informed that the licensee had previously evaluated these relief valves as not requiring periodic testing since they did not perform an accident mitigation function and industry experience showed them to be inherently reliable. The licensee was not able to produce any documented evaluation of this issue. The licensee issued PC 3-C99-2898 to document this issue. The inspectors were informed that the corrective actions for this issue would include a through evaluation of the previous decision to not test these relief valves.

c. Conclusions

An non-cited violation was identified involving a failure to perform additional testing of relief valves after testing identified the valves did not lift at setpoints, as required by ASME/ANSI OM-1987, Part 1 and maintenance procedures.

III. Engineering

E1 Conduct of Engineering

E1.1 Engineering Support for Equipment Problems (37551)

The inspectors monitored Engineering staff support for several equipment problems including intermittent DC system grounds and tripping of a non-safety 12,000 volt breaker supplying power to site air compressors and industrial chiller coolers (A300 line). The inspectors determined that the licensee had assembled thorough action plans that prioritized the problems appropriately for their significance, effectively addressed the causes, and developed long term corrective actions. Another issue previously discussed in Inspection Report 50-302/99-05, was an unisolable through-wall leak on a portion of

the nuclear services and decay heat seawater system (RW). The licensee continued to monitor the flaw for growth via ultrasonic testing to ensure the flaw size remained within allowable code limits. The inspectors reviewed the results of the ultrasonic testing and the licensee's submitted ASME Code Class III relief request and did not identify any discrepancies. Housekeeping measures employed to stop the leak continued to be effective. The inspectors concluded engineering support for the noted plant issues was effective.

E1.2 Review of Design Changes Planned for Implementation in Next Refueling Outage

a. Inspection Scope (37550)

The inspectors began a review of three safety significant design change packages the licensee planned to implement during the fall 1999 refueling outage. The systems being modified were the emergency feedwater system, the high pressure injection system and the low pressure injection system. The changes are extensive and include installation of additional piping, valves, a new building, and an additional emergency feedwater pump. The concept of the changes was known to the NRC for some time, and the appropriate Safety Evaluations and revised Technical Specifications have been issued. The NRC inspection effort for the design changes will continue during the upcoming outage period.

b. Observations and Findings

General

The design packages were prepared by a contracted engineering firm with oversight by licensee management and engineers. The inspectors found that the basic format of the design packages was consistent with the licensee's design procedures. The inspectors examined portions of the design change packages and observed that the packages included the licensee's 32 point design checklist, design input requirements (for example a 35 point electrical system design input form), program impact statement checklist and other design control tools. A section of the packages discussed adherence to codes, standards and Regulatory Guides. The packages contained the licensee's safety evaluation and 50.59 evaluation.

The inspectors determined that the conceptual design of the modifications would fulfill the stated objectives.

Electrical

The inspectors found the cable ampacity, cable voltage drop and electrical loading design input records reviewed in detail were correct. These were for conceptual design purposes. The plant design basis calculations were in the process of being updated to reflect the design changes.

Mechanical

In this initial review of the licensee's modifications to mechanical equipment, the inspectors concentrated on the emergency feedwater system design changes. These changes were documented and evaluated in Modification Approval Record (MAR) 98-03-01-02, "Diesel Driven Emergency Feedwater Pump Project -Mechanical Equipment," authorized 3/5/99. The changes consisted of addition of a new diesel driven emergency feedwater pump (EFP-3), associated piping and valves, and support equipment. The inspectors reviewed examples of the associated design drawings, procurement specifications, and calculations.

The inspectors found that the mechanical design documents reviewed were generally thorough and accurate. However, the inspectors noted that the licensee did not have a reference to support an assumed 200 gpm minimum flow used to determine total discharge head (TDH) for pumps EFP-1 and EFP-2 in calculations E-92-0158 and E-92-0159. The inspectors reviewed the head curve for the pumps and verified that the TDH was close to maximum at 200 gpm. The licensee verified that flows measured in surveillance tests supported the 200 gpm minimum.

c. Conclusions

Initial inspection of design change packages for the emergency feedwater system, the high pressure injection system, and the low pressure injection system found that the concept of the changes would fulfill the design objective, the design control process in general was adequate, and the details reviewed were correct.

E2 Engineering Support of Facilities and Equipment

E2.1 Leakage Sources Outside Containment Program

a. Inspection Scope (61726, 37551)

Significant seal ring leakage existed on the normal make-up system isolation valve, MUV-27. Since this valve is outside containment, inspectors reviewed how the leakage was accounted for in the reactor coolant system (RCS) leakage sources program required by Technical Specifications (TS) 5.6.2.4. The inspectors reviewed the administrative program outline, surveillance procedures, Final Safety Analysis Report (FSAR) limits, and supporting calculations. The inspectors also reviewed licensee post-Three Mile Island (TMI) commitments related to the program.

b. Observations and Findings

The inspectors determined the program scope effectively encompassed the decay heat removal (DH) system and building spray system (BS) reactor building sump recirculation paths outside containment, but was limited for the makeup system (MU). Although MU could also be recirculating sump water when in piggy-back mode, the program did not specifically test MU for leakage, instead relying on the normal online RCS leakage

surveillance to capture all MU system leakage. Program walkdowns were also limited and online leakage was not actively tracked. However, the inspectors observed a revision to Surveillance Procedure (SP) 412, Emergency Core Cooling System Leakrate Test, implemented during the inspection, raised the program standards to be more pro-active, improved walkdowns, and added specific leakage testing of MU. The inspectors identified some minor administrative errors with scope and acceptance criteria, but determined the revised program was effective. The licensee initiated actions to correct the administrative errors. The inspectors also reviewed the previous performance documents for SP-412 and did not identify any discrepancies.

The inspectors confirmed that the licensee fulfilled all of the documented program commitments made in response to post-TMI guidance in NUREG 0578 and 0737. The inspectors reviewed Dose Calculation I-86-0003, revision 8, and FSAR design basis accident limits and assumptions and observed that the current analysis contained little margin to the 10 CFR 100 limit on thyroid dose. However, licensee assumptions were conservative and SP-412 leakage limits (0.595 gallons per hour) were well below the leakage assumed in the analysis. The leakage from MUV-27 was approximately 0.32 gallons per minute, well in excess of the acceptance criteria. When questioned, the System Engineer stated that the leakage was not applicable to the program since the MUV-27 seal ring would not be exposed to system pressure when the valve was closed as it would be in any sump recirculation scenario. The inspectors confirmed this aspect of MUV-27 design. The engineering assumption was documented in an informal plan written when MUV-27 leakage first appeared in April 1999. It had not been formally documented in the licensee corrective action system per licensee guidelines when the leakage worsened. However, the inspectors found the plan to be adequate to disposition the MUV-27 leakage and confirmed it had been promulgated to the operating shifts. A PC was subsequently initiated. The assumption for leakage when MUV-27 is closed was confirmed on September 24 when a MU control valve failed. Operators closed MUV-27 in response and confirmed all of the seal ring leakage stopped.

c. Conclusions

Implementation of controls to minimize primary coolant leakage sources outside containment were effective. Calculations and surveillance limits were conservative and licensee program commitments were fulfilled. Justification to exclude seal ring leakage from a makeup system isolation valve was appropriate. Recent improvements to the program included specific testing of makeup system piping for leakage and more pro-active leakage monitoring.

E2.2 New Fuel Receipt and Handling (37551)

The inspectors observed licensee activities surrounding receipt, inspection and transfer of new fuel. This was a first time evolution for Maintenance personnel. Previously, Operations personnel, with Reactor Engineering oversight, usually performed new fuel receipt. The inspectors noted Reactor Engineering personnel presence at all times, as well as frequent visits by their supervisor. No problems with new fuel receipt were noted by the inspectors or the licensee and necessary precautions were taken prior to and

during all fuel handling. Proper rigging and testing of fuel handling equipment was performed. The inspectors concluded that Maintenance personnel performed in an exemplary manner considering this was their first time performing this activity. All the new fuel was determined to be acceptable.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Licensee Event Report (LER) 50-302/97-38-01: An Engineering Oversight Resulted in Operation Outside of the Design Basis for the Waste Disposal System. After further review, the licensee concluded that the identified components of the waste disposal system satisfied the plant design basis. A 1977 modification moved a seismic boundary, but did not accurately update the seismic design basis description. The seismic class criteria was always met and provided adequate protection against uncontrolled release of activity. Current licensee controls are adequate to prevent another occurrence of a failure to update the plant licensing basis. The inspectors reviewed the documentation and applicable FSAR sections and concluded the licensee's evaluation was adequate and sufficient to consider this item closed. Enforcement aspects of this issue were previously discussed in NRC Inspection Report 50-302/98-04.

E8.2 (Open) Inspector Followup Item (IFI) 50-302/97-17-03: Review of Cable Ampacity Issue. The licensee's progress toward resolving the cable ampacity issue was reviewed. The inspectors found that the licensee's final report, which was being prepared by an outside engineering firm, was not complete. The inspectors were informed that the engineering firm's report will be available by October 29, 1999. Additionally, the licensee was in the process of examining certain cables with the "indentor" test methodology, which has been discussed in the NRC report which established this open item. The inspectors performed sufficient detailed inspection to conclude that the licensee has identified all the potentially undersized cables. The potentially undersized cables are all in cable trays, none are in conduit or ductline. Included in the set of potential problem cable tray sections are: (1) about two dozen 480 V power trays, (2) a few control trays where small power was run with the control cables and (3) the diesel generator leads. After discussing the planned methodology for resolving this issue with the responsible engineer and supervisor engineer, the inspectors concluded that the engineering firm's report and the licensee's cable inspections should be completed before the end of the fall 1999 refueling outage.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Conduct of Radiological Protection Controls (71750)

The inspectors routinely toured the Radiological Control Areas (RCA) and observed work activities, personnel radiological control practices, radiological area and container postings. Observed plant personnel demonstrated appropriate application of radiological control practices. Health physics technicians provided positive control and support of work activities in the RCA. The inspectors questioned posted contamination areas in the

Maintenance Support Building that were exposed to wind and the elements via open roll-up doors. Although the licensee confirmed the material had only fixed contamination and was not subject to an unmonitored release, they closed the roll-up doors as a prudent measure. A release of Waste Decay Tank WDT-10B was observed on August 18. The release was performed per the procedure and radiation monitor alarms were reset appropriately. No concerns were identified.

V. Management Meetings

X1 Exit Meeting Summary

The inspection scope and findings were summarized on September 27, 1999. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

PARTIAL LIST OF PERSONS CONTACTED

Licensees

S. Bernhoft, Director, Nuclear Regulatory Affairs
J. Cowan, Vice President, Nuclear Operations
R. Davis, Assistant Plant Director, Operations
R. Grazio, Director, Nuclear Site and Business Support
G. Halnon, Director, Nuclear Quality Programs
J. Holden, Vice President and Director, Site Nuclear Operations
C. Pardee, Director, Nuclear Plant Operations
D. Roderick, Director, Nuclear Engineering & Projects
M. Schiavoni, Assistant Plant Director, Maintenance
T. Taylor, Director, Nuclear Operations Training

NRC

W. Bearden, Reactor Inspector, Region II (August 30-September 3, 1999)
P. Fillion, Reactor Inspector, Region II (August 30-September 3, 1999)
E. Girard, Reactor Inspector, Region II (August 30-September 3, 1999)
T. Johnson, Senior Resident Inspector, Farley (August 23-27, 1999)
L. Mellen, Reactor Engineer, Region II (August 16-19, 1999)
G. Warnick, Resident Inspector, St. Lucie (August 23-27, 1999)

INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving and Preventing Problems
IP 62700:	Maintenance Implementation

IP 62707:	Conduct of Maintenance
IP 61726:	Surveillance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92901:	Follow up - Operations
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-302/99-06-01	NCV	Two Examples of Failure to Fulfill Clearance Process Requirements (Section O4.1)
50-302/99-06-02	NCV	Failure to Expand Sample for ASME Class 2 and 3 Relief Valves (Section M2.2).

Closed

50-302/99-06-01	NCV	Two Examples of Failure to Fulfill Clearance Process Requirements (Section O4.1)
50-302/99-06-02	NCV	Failure to Expand Sample for ASME Class 2 and 3 Relief Valves (Section M2.2).
50-302/97-38-01	LER	Engineering Oversight Resulted in Operation Outside of the Design Basis for the Waste Disposal System (Section E8.1)
50-302/97-12-02	VIO	Inadequate Corrective Actions (Section O8.4)
50-302/98-02-01	VIO	Inadequate Corrective Actions to Recently Identified Deficiencies Associated with EOP Actions (Section O8.1)
50-302/98-02-05	IFI	Consideration of Obstruction of In-plant EOP Actions by Maintenance (Section O8.3)
50-302/98-02-09	VIO	Inadequate Piggyback Testing (Section O8.2)

Discussed

50-302/97-17-03	IFI	Review of Cable Ampacity Issue (Section E8.2)