

U.S. NUCLEAR REGULATORY COMMISSION

REGION 2

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Report No: 50-302/97-01

Licensee: Florida Power Corporation

Facility: Crystal River 3 Nuclear Station

Location: 15760 West Power Line Street
Crystal River, FL 34428-6708

Dates: January 12 through February 22, 1997

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T. Cooper, Resident Inspector
B. Crowley, Reactor Inspector, paragraphs E2.1, E8.1,
E8.4, E8.10
P. Fillion, Reactor Inspector, paragraph E8.5
L. Mellen, Project Engineer, paragraphs E8.4, E8.7
L. Raghavan, Project Manager, paragraph E1.4
R. Schin, Reactor Inspector, paragraphs E1.3, E8.2,
E8.3
M. Thomas, Reactor Inspector, paragraphs E8.6, E8.8,
E8.9

Approved by: K. Landis, Chief, Projects Branch 3
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EXECUTIVE SUMMARY

Crystal River 3 Nuclear Station NRC Inspection Report 50-302/97-01

This integrated inspection included aspects of licensee performance in operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by four reactor inspectors, the project engineer from Region II, and the NRR project manager.

Operations

Problems with inconsistent logging criteria and unclear and unenforced procedural expectations were observed by the inspectors in operations logs (paragraph 01.2).

A Violation (VIO 50-302/97-01-01) was identified for clearance tagging requirements which were inadequate to preclude personnel and equipment hazards and resulted in a valve being repositioned while under a red tag clearance (paragraph 01.3).

Several attention to detail and poor process problems indicated that deficiencies could exist in the licensee's expectations and process for configuration and status control of plant equipment (paragraphs 01.3, 01.4, and 01.5).

A Violation (VIO 50-302/97-01-02) was identified for failure to follow procedures, resulting in an inadvertent emergency diesel generator start. Contributors to this event, such as poor briefing and preparation of the operator, assigning the operator to extraneous tasks during the performance of a time sensitive evolution, and the operator failing to perform vital steps of the procedure are indicative of performance problems which still exist in plant operations (paragraph 01.6).

The licensee staff exhibited an adequate level of conservative decision making and questioning attitude. Several good examples were observed but some poor examples continue to be found. Licensee management continues to emphasize development of a conservative safety culture (paragraph 04.1).

Licensee self-assessment activities were being actively restructured in an attempt to improve their effectiveness. Some change related problems were observed due to implementing new programs (paragraph 07.1).

The inspectors concluded the new corrective action program was functioning adequately, but several deficiencies detracted from its effectiveness. The licensee was actively working to improve the process and correct these deficiencies (paragraph 07.2).

Maintenance

Several personnel errors and programmatic instrument calibration problems were identified as a Violation (VIO 50-302/97-01-04) of Technical Specification

Surveillance Requirement 3.7.13.1 for spent fuel pool level verifications (paragraph M1.1).

The decision to assess the maintenance controls of the plant computer was a proactive initiative on the part of licensee management. The assessment resulted in more stringent controls being implemented (paragraph M1.2).

Problems were encountered throughout the performance of the Emergency Diesel Generator 1A outage. Lack of coordination was identified as a key contributor. A weakness was identified for the absence of a mechanism to ensure that tasks scheduled for the weekend that were not completed were rescheduled for the subsequent week (paragraph M1.3).

A Non-Cited Violation (NCV 50-302/97-01-05) was identified for an inadequate surveillance procedure to test the operability of the toxic gas chlorine detectors (paragraph M1.5).

Weaknesses were identified with licensee work planning. Work packages were planned for inappropriate plant conditions, were provided to field operators unfamiliar with the impact of the task, and were not thoroughly evaluated for control impacts and updated to preclude future problems (paragraphs M1.6, M1.7).

Engineering

The inspectors observed good support from Technical Support system engineers to Operations for emergent issues (paragraph E1.1).

A Non-Cited Violation (NCV 50-302/97-01-10) was identified for inadequate design control, Non-Safety Related Components in Safety Related Applications - Two Examples: Thyrite Surge Protection Device, Operator and Controller for MUV-103. The licensee has taken the necessary immediate corrective actions and has added final resolution of these issues to the restart restraint list (paragraph E1.2).

An Unresolved Item (URI 50-302/97-01-06) was identified regarding concerns with the design, licensing basis, and Technical Specifications for the high pressure injection system. In addition, the inspector noted that the licensee's recently completed extent of condition review (time line) for the makeup/HPI system design did not identify any of these concerns (paragraph E1.3).

The inspectors noted improvement in the quality and thoroughness of 50.59 evaluations for recent engineering products over those generated one - two years ago. However, the sample size reviewed was small and therefore, further review will be required to verify improvements and acceptability of the overall 50.59 program (paragraph E1.4).

The licensee discovered problems with diesel generator test instrumentation inaccuracy that was not factored into surveillance testing requirements, potentially rendering the diesel generators inoperable. However, the corrective action was timely and thorough and the inspectors considered it an

example of a problem found as corrective action for a previous problem (paragraph E1.6).

An error in the FSAR was identified, where the FSAR stated incorrectly that for a design basis accident the peak cladding temperature would exceed 2300 degrees F (the regulatory limit is 2200 degrees F). In addition, the inspector noted that the licensee's current FSAR review project had not identified this FSAR error (paragraph E1.1).

The inspectors noted that the licensee's definition of a design basis issue, as defined in Procedures CP-111, CP-150, and CP-151 was not clearly broad enough to ensure that the requirements of 10 CFR 50, Appendix B, Criterion III; 10 CFR 50.72; and 10 CFR 50.73 would be met (paragraph E2.1).

The inspectors followed up on and closed a total of three violations and one Licensee Event Report (paragraphs E8.1, E8.2, E8.3).

A violation (VIO 50-302/97-01-07) was identified for inadequate design control in that design assumptions for Auxiliary Building temperatures used in the Environmental and Seismic Qualification Program Manual (ESQPM) and instrument loop uncertainty setpoint calculations were not properly translated into procedures for calibration of instruments, the Enhanced Design Basis Document, or the Final Safety Analysis Report. Additionally, there were no procedures for ensuring the Auxiliary Building temperatures would be maintained within the ranges assumed by the ESQPM and instrument setpoint calculations and there were no records of daily temperatures in the Auxiliary Building (paragraph E8.4).

A violation (VIO 50-302/97-01-09) was identified for inadequate corrective actions for cable ampacity (paragraph E8.5).

An Unresolved Item (URI 50-302/97-01-08) was identified regarding the adequacy of procedures to take the plant from hot standby to cold shutdown from outside the control room in the event of a fire (paragraph E8.6).

The inspectors noted that the licensee performed detailed evaluations and is developing solutions for the issues identified in GL 96-06. Overall, the Modification Approval Record package, including the 10 CFR 50.59 evaluation, design, procurement, and installation of the containment penetration process piping expansion chambers was detailed and well documented, demonstrating good Engineering performance. One weakness was identified concerning completion of the ISI Requirements check-sheet (paragraph E8.10).

Plant Support

On January 30, 1997, a second example of violation No. A(4)(01043) which was issued in EA 97-012 was identified by the creation of a penetration path into the protected area via a breach in a condenser waterbox (paragraph S1.1).

A Non-Cited Violation (NCV 50-302/97-01-03) was identified for an inadequate fire system recirculation procedure. System recirculation flow limits were not included in system procedures or the Fire Protection Plan, resulting in all fire pumps inadvertently being rendered inoperable (paragraph F3.1).

The inspectors assessed the licensee's performance concerning the five areas of continuing NRC concern in the following paragraphs: the assessment is limited to the specific issue addressed in the respective paragraph:

NRC AREA OF CONCERN	ASSESSMENT PARAGRAPH													
	E1.2	E1.5	E1.6	E2.1	E8.1	E8.2	E8.3	E8.4	E8.5	E8.6	E8.7	E8.8	E8.9	E8.10
Management Oversight	G	G	G	A	G	A	G	I	A	A	G	A	A	G
Engineering Effectiveness	G	G	G		G	A	G	I	I	G	G	G	A	G
Knowledge of design basis	G	G	G					I	A	G	A			G
Compliance With Regulations	G	G	G	A	G	A	G	I	I	I	G	G	G	G
Operator Performance			G								A			

S = Superior G = Good A = Adequate/Acceptable I = Inadequate Blank = Not Evaluated/Insufficient Information

E1.2: 10 CFR 50.59 Safety Evaluations

E1.5: Decay Heat Valve (DHV) 21 Operability Evaluation

E1.6: Evaluation of Dranetz Test Instrument Inaccuracies on Emergency Diesel Generator Testing

E2.1: Corrective Action and Reportability Issues

E8.1: Corrective actions for Violation 50-302/96-05-05, Failure to Follow Procedures for Updating Design Basis Documents

E8.2: Corrective actions for Violation 50-302/96-05-07, Inadequate Receiving Inspections for Battery Chargers; and Licensee Event Report 96-12-02, Operation Outside Design Basis Caused by Battery Chargers Having Inadequate Test Results Accepted in Error

E8.3: Corrective actions for Violation 50-302/96-05-08, Failure to Follow Purchasing Procedures for Inverters

E8.4: EA 95-16, Use of Nonconservative Trip Setpoints for Safety-Related Equipment

E8.5: IFI 96-201-13, Cable Ampacity Exceeded for DHP-1A [DCP-1A] Feeder Cable and Others

E8.6: Unresolved Item (URI) 50-302/96-201-04, Nonsafety-Related Positioners on Safety-Related Valves

E8.7: Inspector Followup Item (IFI) 50-302/95-15-01, Design Requirements for Nitrogen Overpressure

E8.8: VIO 50-302/96-09-07, Inadequate Corrective Action for Implementation of EFIC Task Force Recommendations

E8.9: VIO 50-302/95-21-03, Failure to Isolate the Class IE from the Non Class IE Electrical Circuitry for the Reactor Building Purge and Mini-Purge Valves

E8.10: NRC Generic Letter 96-06, Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

Report Details

Summary of Plant Status

The unit remained in Mode 5 throughout the inspection period, continuing in the outage that began on September 2, 1996. An outage on the "A" train of emergency core cooling system (ECCS) equipment was conducted to perform corrective maintenance and implement a design change on the 1A Emergency Diesel Generator (EDG) to upgrade the EDG turbocharger nozzle rings and replace the intercooler with a more efficient version. These changes were expected to result in 150 kilowatts (Kw) of increased diesel capacity. The 1B EDG will be upgraded during a pending "B" train outage. The development of other modification packages continues, although no major modification began implementation during this inspection period.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

Using Inspection Procedure 71707 the inspectors conducted frequent reviews of ongoing plant operations. Operators were professional in that control room access was well controlled, communications were normally thorough, and alarm response was good. The inspectors observed several shift turnover meetings and observed that they were generally formal and information was effectively communicated. Members of various support groups such as the duty Technical Support system engineer attended to support Operations needs.

As discussed in paragraphs M1.3, M1.6 and M1.7, the inspectors observed several examples of inadequate communications and scheduling between Operations and Maintenance personnel that resulted in challenges to the operators and missed post-maintenance tests.

Housekeeping in the plant was routinely monitored and found to be adequate although several examples of poor control of maintenance equipment adjacent to protected train components were identified by the inspectors. None of the noted discrepancies comprised a significant operational concern.

Overall, the inspectors observed some good examples of conservative decision making and questioning attitude by plant operators as discussed in paragraphs 01.4 and 04.1. However, several attention to detail and poor process problems discussed in paragraphs 01.4, 5 and 6 below caused the inspectors to conclude that deficiencies existed in the licensee's process for configuration and status control of plant equipment.

01.2 Operator Logs (71707)

The inspectors identified several significant items discussed elsewhere in this report such as an inadvertent EDG start and a subsequent Operations investigation, a protected area security breach, and mispositioned valves that were not logged in the Operations Shift

Supervisor logs. The inspectors also identified equipment removed from service such as Chill Water Pump 1A which was entered in narrative logs but not in the Equipment Out of Service tracking log. The inspectors also observed inconsistencies between Shift Supervisor and Shift Manager logs and between individual Shift Supervisors logs. The inspectors reviewed Operations Instruction OI-5, Log Keeping, Revision 2, and observed that several requirements were not clear and those that were clear were not consistently enforced by management. Requirements such as logging the time of turnover were not being implemented by Shift Supervisors on Duty (SSOD) nor expected by management. Additionally, practices such as recording log entry times versus event occurrence times in the SSOD logs were not delineated in OI-5. The inspector observed that there was no guidance on the content of Shift Manager (SM) logs nor guidance on the coordination between the SM and SSOD logs, both of which often contain the same content. The inspector discussed these observations with Operations management who issued a Night Order on February 4 clarifying management expectations for log entry thresholds. The licensee incorporated these deficiencies in their revision to OI-5 being developed as an action for their Management Corrective Action Plan II (MCAP). The inspectors concluded licensee management had not made their expectations clear and had not held SSODs accountable to the expectations in OI-5.

01.3 Valve Stroked While Red Tagged Under a Clearance

a. Inspection Scope (71707)

On February 6, 1997, condenser water box air removal (AR) valve ARV-1 was opened while red tagged under an active clearance which supported waterbox work. The inspectors evaluated the licensee's response to the problem.

b. Observations and Findings

Tagging Order 97-1-140 was issued to support mechanical work in the D waterbox of the main condenser. Tag R-008 was hung to require the main control board switch for valve ARV-1 to be in the closed position. This was the only point of control and the only tag hung for ARV-1, which was an air-operated valve. On February 6 the instrument technician assigned to perform work on the solenoid valve in the air supply line to the valve operator for ARV-1 was directed to verify the failure mode of the valve. The technician reported that ARV-1 failed open on loss of air, was not tagged, and was within the red tagged boundary of the mechanical work clearance. Neither the technician nor SSOD was aware that ARV-1 was red tagged closed on the main control board. Consequently, the technician was authorized by the SSOD to work on the solenoid. Although the control room operators recognized after the technician left that ARV-1 was red tagged and they tried to page him, they were unable to contact him and ARV-1 opened when he started to work on the solenoid. The potential consequences were minimized because the technician, although not required by procedure, had alerted the mechanical workers to exit the waterbox prior to his solenoid work because he knew ARV-1

workers. Nevertheless the inspectors were very concerned that a valve was able to be opened when on an active clearance, was not tagged locally, and was a fail-open air-operated valve that was not gagged shut. The licensee's clearance Procedure CP-115, Nuclear Plant Tags and Tagging Orders, Revision 73, did not require local tagging of components or gagging of air-operated valves unless they were designated as system boundary valves. Even then, CP-115 did not require tags on the components manipulated to gag an air valve or isolate and vent the motive air supply. The inspectors concluded these deficiencies constituted an inadequate procedure which directly contributed to the ARV-1 event. Criterion V of Appendix B to 10 CFR 50, Instruction, Procedures and Drawings, requires in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances. Therefore, the failure of CP-115 to require local tagging of components and specify appropriate controls for gagging of air-operated valves for red-tag clearances is a violation, VIO 50-302/97-01-01, Inadequate Clearance Tagging Requirements.

The licensee took thorough corrective actions the following day after plant management became aware of the event at their morning meeting. However, the inspectors were concerned that the significance was not recognized by shift management at the time of occurrence, and appropriate actions were not implemented until almost 24 hours later. The inspectors also noted that the SSOD did not make an entry in his log discussing the problems on the day of occurrence. After management initiated an Operations Investigation per Operations Instruction 12, Investigation of Abnormal Events, Revision 1, a maintenance and tagging standdown was conducted that lasted three days. The event was briefed to all available maintenance personnel, and approximately 120 tagging orders were verified for adequacy. The licensee found numerous examples that did not comply with CP-115 requirements or management expectations; these were documented on corrective action system precursor card (PC) 97-0921. These included 27 examples of components that were system boundaries but were not annotated as boundary valves on tagging orders, ten examples of local control points not tagged, and two examples of air valves not in their fail safe position. The licensee also found that different operators had varying methods of implementing identical clearance orders. This indicated to the inspectors that CP-115 guidance was not clear and that licensee management was not adequately overseeing the process to ensure expectations were met and clearance orders were consistent. The inspectors also reviewed CP-115 and concluded the format was primarily an unprioritized listing of requirements which contributed to the inconsistent implementation.

Licensee management was already concerned about a perceived negative trend in tagging orders implemented per CP-115 and had initiated a root cause investigation under PC 96-5487 on December 5, 1996. However, this corrective action effort was assigned a due date of February 15, 1997, so it was not timely enough to preclude this event. The licensee incorporated their findings and corrective actions for the above problems into the ongoing investigation.

c. Conclusions

Although the inspectors determined the resultant safety impact of this event was minor, the potential exists for further violations of the integrity of the clearance program. The inspectors were very concerned that similar communications errors and program deficiencies could result in a more significant hazardous situation. The inspectors considered these problems to be indicative of potential deficiencies in the licensee's overall process for configuration and status control of plant equipment.

01.4 Venting of Decay Heat Removal System (71707)

The inspectors observed that the Operations staff was concerned about previous problems experienced with restoration of an out of service decay heat removal (DH) system train. Upon opening the system isolation valves between the DH system and the reactor coolant system (RCS), pressurizer liquid level had decreased several inches, indicating air was introduced into the RCS. This occurred even though the DH system had been properly vented per procedure. The Operations staff developed new work instructions (WI) to augment the DH system venting process and verify the amount and location in the RCS where the air collected. The inspector witnessed the Plant Review Committee (PRC) review and approval of these WIs. Although the inspector noted the lack of independent verification in the restoration steps of one of the two WIs, the inspector observed that the licensee effectively addressed concerns with air accumulating in the reactor vessel head and developed conservative guidance to assist the operators. The licensee's efforts were not totally successful because pressurizer level still decreased upon DH system restoration, although less than before. The licensee concluded a new high point vent was required to effectively vent from under the system isolation valves and included that as a restart item on their restart commitment checklist. PC 97-1052 and 1059 were generated to track resolution. The inspectors concluded that the missed independent verification was another example of potential deficiencies in the licensee's overall process for configuration and status control of plant equipment. However, plant operators exhibited a conservative concern and a good effort was made by the licensee to resolve it.

01.5 Mispositioned Valve Events (71707)

The inspectors reviewed the licensee's response to four examples of mispositioned valves that occurred over a three day period. A raw water system vent valve was inadvertently left open by an operator placing a heat exchanger in service and was discovered after a pump start resulted in water flowing from the valve. A nitrogen system valve was found in the incorrect position following maintenance activities. A makeup system valve and station air valve were apparently closed to isolate air leaks without any procedural controls. The licensee appropriately recognized the overall implications of the combined problem and initiated a common root cause investigation. During the review, the inspector questioned the method of control and verification for root

isolation valves to instruments that are commonly operated by instrument technicians. The licensee recognized that they did not have a procedure to verify the position of these valves to pneumatic valve controllers and initiated PC 97-0733 to implement further corrective action. The licensee promptly issued an Operations Study Book entry to promulgate the problems to operators. The licensee's investigation has revealed that equipment alteration logs were not required to be retained as quality records for minor work packages. This made it impossible to verify the last known position or verification of several valves or components, hindering the licensee's investigation. The licensee and inspector also recognized that management's expectations were to perform concurrent and independent verifications. These expectations were developed for previous mispositioning problems and were not being consistently implemented. The licensee's common root cause was being finalized at the close of this Inspection Report period so their final assessment and corrective actions will be reviewed in the next report period. The inspectors considered these problems to be indicative of potential deficiencies in the licensee's overall process for configuration and status control of plant equipment.

01.6 Inadvertent Start of EDG-1A

a. Inspection Scope (71707, 40500)

While performing the Modification Approval Record (MAR) functional test restoration of EDG-1A at 9:18 p.m. on February 1, 1997, during the manual roll of the diesel to clear oil and moisture from the cylinders, the diesel inadvertently started and accelerated to full speed. Control room alarms were received for the automatic start of the diesel generator room fans, AHF-22A and AHF-22B. The control room operator was called by the plant operator performing the restoration, who notified him of the inadvertent start. A Senior Reactor Operator (SRO) and plant operator were dispatched from the control room to secure the diesel generator.

b. Observations and Findings

The inspectors reviewed the licensee's investigation, which revealed that the MAR functional test was originally scheduled to be performed to completion by a dedicated crew that had been extensively briefed and rehearsed for the task. Delays in the performance of the functional test resulted in the dedicated crew being relieved by a crew that received only a face to face turnover on the task.

The procedure to restore the EDG after the MAR functional test, MAR 96-10-05-01 TP-1, Attachment A, stated that after the diesel engine had been stopped for at least 15 minutes, but not more than 20 minutes, steps 4.6.30 through 4.6.34 should be performed. These steps are intended to roll the diesel slowly to vent moisture and oil out of the cylinders. Step 4.6.30 trips the fuel racks, which should prevent an inadvertent diesel start while rolling it with air. The licensee reviewed the procedure for adequacy and concluded that the functional

test procedure was adequate and in sufficient detail to perform the task without failure.

After the diesel had been stopped, but prior to completing the steps to roll the diesel, the control room operator called the plant operator and directed him to perform a different task. The plant operator inquired as to the importance of the function, but did not inform the control room as to the status of the MAR functional test restoration procedure. When the plant operator returned to the MAR functional test procedure, over 19 minutes had elapsed since the diesel had been stopped. The operator proceeded to roll the diesel over, but did not complete all required steps in the procedure, including 4.6.30, which would have prevented an inadvertent diesel start.

Technical Specification (TS) 5.6.1.1 requires, in part, that procedures be implemented covering activities as recommended in Regulatory Guide 1.33, Appendix A, Revision 2, dated February 1978. Appendix A recommends administrative procedures to cover the authorities and responsibilities for safe operation and shutdown, procedure adherence and temporary change method. The licensee implemented the above Appendix A recommendations, in part, through Procedure AI-500, Conduct of Operations and OI-09, Operations Procedures. OI-09 requires that activities will be performed in accordance with approved instructions. The operator's failure to comply with the instructions in MAR 96-10-05-01 TP-1, Attachment A is a violation. VIO 50-302/97-01-02, Failure to Follow Procedures, Resulting in an Inadvertent Emergency Diesel Generator Start.

c. Conclusions

The failure of a non-licensed operator to follow the MAR functional test procedure resulted in an inadvertent emergency diesel generator start. Contributors to this event, such as poor briefing and preparation of the operator, assigning the operator to extraneous tasks during the performance of a time sensitive evolution, and the operator failing to perform vital steps of the procedure are indicative of performance problems which still exist in plant operations.

04 Operator Knowledge and Performance

04.1 Operator Awareness and Questioning Attitude

a. Inspection Scope (71707)

The inspectors continue to monitor operator performance in response to previously documented deficiencies.

b. Observations and Findings

The inspectors have observed numerous examples of operator performance that were indicative of the status of the licensee's safety culture. The licensee has made it a priority to improve this aspect by supporting

and encouraging questioning attitudes and open decision making. Some examples of questioning attitude and conservative decision making included: the control room refusal to authorize inappropriate scheduled Mode 5 work, questioning of the 1B DH pump oil usage trend prior to a train A outage that resulted in delaying the outage for a week to resolve, questioning of DH system venting problems, drain valve work that was conservatively stopped without the normal makeup path in service, and engineered safeguards cabinet work that was stopped due to a fuse concern. The fuse concern turned out to be not a problem but operators conservatively delayed work for a day to ensure their concern was resolved. Another example of questioning attitude was the work of engineering to troubleshoot and discover problems with chlorine monitor testing. These items are discussed elsewhere in this report.

Some examples of poor conservatism and questioning attitude were also observed. They include the scheduling of the inappropriate Mode 5 work caught by the operators, the initial change by the operations shift of fire protection system recirculation flow on verbal and incomplete guidance, late reports required by 10 CFK 50.72 (addressed in IR 50-302/97-04), a poor briefing and preparation of an EDG operator for an evolution, and assigning the EDG operator to extraneous tasks during the performance of a time sensitive evolution which contributed to an inadvertent EDG start due to a missed procedural step.

c. Conclusions

The licensee staff exhibited an adequate level of conservative decision making and questioning attitude. Several good examples were observed but some poor examples continue to be found. Licensee management continues to emphasize development of a conservative safety culture.

06 Operations Organization and Administration

06.1 Effective February 18, 1997, Mr. J. Cowan assumed the duties of Vice President, Nuclear Production, from Mr. P. Beard, Senior Vice President, Nuclear Operations. The following Directors and their departments now report to Mr. Cowan:

- Mr. B. Hickie, Director, Nuclear Plant Operations
- Mr. R. Widell, Director, Training
- Mr. W. Conklin, Director, Materials and Controls
- Mr. D. Kunsemiller, Director, Site Support

The following executives now report to the Senior Vice President, Nuclear Operations (Mr. R. Anderson, effective March 3, 1997):

- Mr. J. Holden, Director, Nuclear Engineering and Projects
- Mr. J. Baumstark, Director, Quality Programs
- Mr. J. Cowan, Vice President, Nuclear Production

07 Quality Assurance in Operations

07.1 Licensee Self-Assessment Activities

a. Inspection Scope (71707, 40500)

The inspectors reviewed various self-assessment activities which included:

- Routine reviews of Nuclear Quality Assessments (NQA) activities;
- Observation of an exit interview for a NQA monthly audit.
- Observation of several Plant Review Committee (PRC) meetings and review of PRC Meeting minutes;
- Observation of the licensee's internal Restart Readiness Review Panel meetings;
- Observations of subcommittee and full Nuclear General Review Committee (NGRC) meetings on January 14 and 15.

b. Observations and Findings

NQA reports appeared thorough and diverse. The inspectors noted several examples of timely and responsive NQA surveillances in potential problem areas. NQA Audit 97-01 had several good findings in the Engineering area, but the inspector observed that an Engineering representative did not attend the audit exit meeting. The licensee recognized the negative impact this had on resolution of the findings and took appropriate corrective action to ensure it would not recur. The inspector reviewed NQA staffing plans and observed that the licensee had established a two year rotation plan for four NQA auditor positions, staggered at six month intervals, and was attempting to target rotation candidates for inclusion into NQA versus accepting other departments' excess personnel. The inspector concluded this would enhance the effectiveness of NQA. The inspector also observed that all NQA findings are entered into the licensee's corrective action program via generation of a Precursor Card (PC) and that the NQA auditor determined the grading of the resultant PC. Changes to the grade and consequently to the level of investigation the PC received had to be concurred on by NQA. The inspector concluded this was a beneficial practice that enhanced NQA ownership of issues.

The PRC provided a thorough review of issues. A good, detailed discussion and rejection of an issue was noted regarding the implementation of modification on reactor building penetration expansion chambers to address Generic Letter 96-06 concerns. Although the inspector observed an omitted independent verification requirement, as discussed in paragraph 01.4, PRC discussion of the DH system venting concern was thorough, conservative, and probing. The committee carefully reviewed an associated 10 CFR 50.59 evaluation and challenged several decision points taken by the author. The chain of custody

forms, implemented to address previous problems regarding implementation of PRC expectations that formed the basis for approving items, appeared to be working successfully. The inspector verified several examples where the completion of an item was delayed until the PRC custody form was completed. At the end of the inspection period, the licensee was in the process of evaluating several restrictions to the use of alternate PRC members and establishing a full time PRC director to increase consistency and oversight. The inspector concluded the licensee's planned changes would increase the effectiveness and value added of the PRC, which has already exhibited improvement from previous PRC performance in the areas of questioning attitude and willingness to set a high standard and to reject items that do not meet that standard. PRC meeting minutes were noted to be thorough and accurate representations of the items presented.

The NGRC conducted an extensive review of site activities. The inspector observed that numerous, new offsite and onsite members have been incorporated and that member expectations were promulgated by the new chairman in an effort to raise the standard of expectations for NGRC conduct and questioning attitude. One offsite member was absent for personal reasons but did ensure his input was considered by faxing in comments and questions. The absent member's subcommittee, the Quality and Regulatory Verification Subcommittee, had all new internal members and was hampered by the absence of the chairman and the lack of guidance and expectations as to the final desired product the subcommittee was to produce. The inspector concluded all subcommittee members needed to review their charter. The inspector also observed that several offsite members departed prior to the conclusion of the NGRC agenda due to it being longer than in the past. The inspector discussed these observations with the NGRC Chairman who is taking corrective action. The inspector concluded that the NGRC exhibited an atmosphere supporting rigorous questioning and open discussion that was supportive of their role as site management oversight.

c. Conclusions

The inspectors concluded the licensee was actively restructuring their self-assessment activities in an attempt to improve their programs. Although some problems were observed, they were primarily change related and due to people gaining familiarity with a new process or a new program.

07.2 Implementation of New Corrective Action Program

a. Inspection Scope (71707, 40500)

The inspectors have continually monitored the new corrective action process the licensee implemented in November of 1996 by the following:

- Reviews of most precursor cards entered in to the system;
- Observation of a management CARB meeting;

- Observations of corrective action Precursor Card Screening Committee meetings.

b. Observations and Findings

The inspectors observed that the licensee's program as defined by CP-111, Processing of Precursor Cards for Corrective Action program, Revision 55, still contained numerous deficiencies and poorly defined expectations. However, the licensee's new corrective program manager, who assumed his position in January 1997, has recognized several of the same problems in parallel and was actively developing changes to the process. Examples of the problems observed by the inspectors and the licensee included:

- initial event corrective action not covered under the scope of the precursor card;
- no specific requirement to verify extent of condition for a problem adverse to quality;
- the role of the CARB is not well defined;
- lack of specific standard formats;
- granting of extensions controlled by root cause leaders doing the work; and
- poor management visibility and knowledge of timeliness and root cause investigation status;

The inspectors also observed that the program was burdensome to administer due to the large number of PCs. Approximately one thousand PCs were initiated in January 1997, which indicated the process had an appropriately low threshold, although thoroughly dispositioning this many problems remained a challenge to the licensee.

c. Conclusions

The inspectors concluded the corrective action program was functioning adequately, but several deficiencies detracted from its effectiveness. The licensee was actively working to improve the process and correct these deficiencies.

07.3 Management Assessment in Plant Operations

a. Inspection Scope (40500)

The inspectors reviewed the first month's results of the licensee's initiative to monitor supervisory effectiveness in the area of operations.

b. Observations and Findings

The licensee has begun an initiative to evaluate management oversight effectiveness in the area of operations. The performance indicators chosen included the following:

- tracking the amount of time assessing operations by not only the operations department, but by maintenance, engineering, plant management, shift managers, and senior managers;
- tracking the amount of crew observations by shift supervisory personnel;
- a composite ranking of crew performance: (This was done by assessing the results of all observations by all departments); and
- assessing the operators in: knowledge, procedure use, questioning attitude, communications, self-checking, briefings, teamwork, and safety.

The inspectors reviewed the results of the first month of assessment. It was noted that this program was new and disparities existed in performance assessments for the same crews between the various groups. The licensee has also identified this and was working to develop better criteria. It was also noted that some groups and shift supervisors were not meeting expectations for performing observations.

c. Conclusions

The inspectors realized that since this was a new program and that with just the single data point, no conclusions could be reached. The inspectors will continue to follow the implementation of the program to assess its effectiveness.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) VIO 50-302/96-05-01: Failure to Follow Procedures to Initiate Corrective Action for Bent Main Steam Line Hangers.

(Closed) URI 50-302/96-05-02: Design Concerns with the Main Steam Line Hangers Used in Seismic and Other Dynamic Load Applications

Details of these problems were previously documented in Inspection Report (IR) 50-302/96-05. The technical adequacy of the licensee's response to these problems was reviewed and accepted by the NRC staff as documented in a letter to Florida Power Corporation (FPC) dated January 22, 1997. The inspectors verified that the licensee had appropriately initiated corrective actions for subsequent suspected operability problems. Consequently, this item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Spent Fuel Pool Level Transmitters

a. Inspection Scope (61726, 62707)

Evaluate that maintenance and surveillances of the Spent Fuel Pool Level Transmitters are conducted in accordance with TS 3.7.13

b. Observations and Findings

On October 31, 1996, it was recognized by the licensee that the instruments normally used to perform Technical Specification (TS) surveillance requirement (SR) 3.7.13.1 were out of calibration. Work Request (WR) NU 0338665 was written on that day to fabricate a measuring stick, which could be used to measure spent fuel pool level.

TS 3.7.13 requires that during irradiated fuel movement, at least once per seven days, the spent fuel pool level be verified to be greater than 156 feet above plant datum. Level Transmitters SF-1-LT1 and SF-1-LT2 feed indicators in the main control room which are normally used for the TS surveillance.

Instrumentation and Control (I&C) shop technicians attempted to calibrate SF-1-LT1, but were unable to calibrate the instrument within the required .5% tolerance. The licensee issued Precursor Card (PC) 96-5697 on December 16, 1996, to document that both instruments were out of calibration and that SF-1-LT1 could not be calibrated within tolerance.

The licensee completed an apparent cause determination on January 15, 1997. As part of the apparent cause determination, the licensee evaluated the issue and concluded that no TS violations had occurred. This was based on the premise that, since the surveillance procedure acceptance criteria were conservative compared to the TS requirements, any drift of the instrument would be accounted for. This position was challenged by the inspectors. Surveillances must be completed with calibrated instrumentation to be valid.

As part of the apparent cause determination, the licensee reviewed the calibration history of these instruments. It was identified that the last time SF-1-LT2 was calibrated was February 28, 1992, and the last time SF-1-LT1 was calibrated was in November 10, 1987. The licensee's calibration program required these instruments to be calibrated once every two years.

The inspector reviewed the last completed data sheets for both instruments. While a complete calibration was completed on SF-1-LT2, only a single point calibration was completed on SF-1-LT1 which simply compared the transmitter to the level indicator reading. This was

performed on November 10, 1987, but the review and approval was not completed until February 1, 1988.

The inspector's review located a completed Problem Report (PR) 90-8002, which was written on November 21, 1990, to identify that SF-1-LT1 and SF-1-LT2 were out of calibration. At that time, operations was notified that the instruments were inoperable and could not be used for the surveillance. The PR also had a corrective action to periodically notify the operations department that the instruments were inoperable until the problem was corrected. Under the corrective actions for this PR, WR 271688 was completed for SF-1-LT2 on December 14, 1990. However, a note was attached to the PR which stated that WR 271687, written for SF-1-LT1, could not be completed as the instrument would not calibrate within tolerances. As a result of the inability to calibrate the instrument, Request for Engineering Assistance (REA) 91-114 was written on February 4, 1991. The PR was closed on February 11, 1991, with a statement that all corrective actions were completed. SF-1-LT1 was not in calibration at that time, but an engineering hold was placed on the calibration of the instruments, pending the completion of the REA actions.

The REA stated that the instrument could not be calibrated and that parts were becoming hard to obtain. Original plans under the REA were to replace the existing displacer system with ultrasonic level indicators. However, when problems were encountered with ultrasonic level indicators installed on a different system, the proposed modification was cancelled. No other corrective actions were taken.

During the period while SF-1-LT1 was out of calibration, there were ten periods during which irradiated fuel was moved. During the period while both of the instruments were out of calibration, there were five periods when irradiated fuel was moved. Technical Specification Surveillance Requirement 3.7.13.1 requires that the licensee verify the fuel storage pool water level is ≥ 156 foot above plant datum once per 7 days during movement of irradiated fuel assemblies in the fuel storage pool. The failure to perform a valid surveillance is a violation, VIO 50-302/97-01-04, Failure to Perform Technical Specification Surveillance for Spent Fuel Pool Level.

Following identification of weaknesses by the licensee and the inspectors in the original apparent cause determination, the licensee upgraded the PC to a level B, which requires a formal root cause evaluation.

While performing the root cause evaluation, one of the causes identified was a break down in the preventative maintenance (PM) process which calibrated in-field instruments. It was identified that if the PM had been deferred, it often was not rescheduled. The licensee identified approximately 150 instruments that were out of calibration and an additional 720 instruments that were past the nominal calibration date, but still within the allowed 25 percent grace period.

The licensee evaluated the out of calibration instruments and identified several instances where the instruments were used in safety related applications for operating data or surveillances. Four PCs were issued to address these issues. EDG-1B was declared conditionally operable and potentially inoperable based on out of calibration jacket coolant water temperature instruments. The licensee verified that redundant calibrated instruments were available on the diesel generator. The licensee is taking corrective actions to address these identified deficiencies. Programmatic weaknesses which contributed to the violation are being assessed by the licensee.

c. Conclusions

Several personnel errors and programmatic instrument calibration problems were identified as a Violation (VIO 50-302/97-01-04) of technical specification surveillance requirement 3.7.13.1 for Spent Fuel Pool Level verifications.

M1.2 Work Controls on the Plant Computer

a. Inspection Scope (62707)

The inspectors reviewed an initiative by the licensee to evaluate and improve work controls on the plant computers.

b. Observation and Findings

In response to concerns identified by the Director, Nuclear Plant Operations (DNPO), a surveillance was performed by the Quality Programs department on work controls on the plant computers. These computers are used in the main control room for various parameter monitoring and alarm functions.

The surveillance, QPS-97-0003 was completed on January 10, 1997, and presented to the DNPO in the daily staff meeting. The surveillance identified several areas where weaknesses were evident and improvements were recommended. These identified weaknesses were as follows.

- A PM/surveillance program had not been established to ensure reliability of the plant computer. Maintenance had only been performed on the computer when the system failed.
- The entry conditions for licensee procedure AP-430, Loss of Control Room Alarms were nonconservative. Partial plant computer loss may be sustained, rendering critical plant parameters unavailable, but a partial loss was not explicitly addressed in the procedure.
- Work activities being performed to troubleshoot and repair the plant computer, taking place under WR NU 339899, were outside the scope of the WR

- Poor work practices were evident as a result of an inspection of the Plant Computer cabinets and component terminations.

The licensee maintenance and system engineering management agreed that any work performed on the plant computer, other than rebooting, and be done under a WR, with I&C support. This agreement was documented by an internal memorandum from the Manager, Nuclear Plant Technical Support to the DNPO.

To date, corrective actions to address the other identified weaknesses have not been performed. An initial assessment of AP-430 by operations was that no weakness existed, but this was rejected by the Quality Programs department and returned to operations for further review.

c. Conclusions

The decision to assess the maintenance controls of the plant computer was a proactive initiative on the part of the licensee management. The assessment resulted in more stringent controls being implemented.

M1.3 Maintenance Observations

a. Inspection Scope (62707, 92902, 62703)

The inspectors observed maintenance activities during the EDG-1A system outage. Adherence to work instructions, resolution of identified problems, proper maintenance practices and documentation were assessed.

b. Observations and Findings

WR NU 0339596 was written by the licensee to perform an upgrade to EDG-1A to allow a larger continuous run rating. New turbochargers and dual-pass combustion air intercoolers were installed in accordance with MAR 96-10-05-01. During the various periods that the inspectors witnessed the work, good Foreign Material Exclusion (FME) controls and work control practices were observed. Continual presence by engineering, both systems and design, and maintenance management was observed. The work practices observed in the field revealed no problems.

Problems were encountered with other aspects of the task, however. The original scope of the diesel outage was scheduled for approximately one week. Delays and other problems resulted in the outage taking approximately two weeks to complete.

On January 22, 1997, the mechanical maintenance technicians working on the diesel witnessed electrical arcing which was reported to management. WR NU 340315 was issued to trouble shoot and repair the observed problems. The inspectors reviewed the electrical maintenance and I&C logs and found that on three occasions technicians were dispatched who were unable to locate the arcing. These delays resulted in delays to restart of the diesel following completion of maintenance and modifications. The I&C technician did not consult with the mechanical

maintenance technician, concerning the exact location of the arcing, until the outage schedule had been impacted. Quality Programs, as part of Audit 97-01, issued PC 97-806 on January 30, 1997, stating that the functional test of MAR 96-10-05-01 was delayed as a result of management's failure to recognize the impact that performing the WR would have on the test.

The trouble shooting finally identified, on January 30, 1997, that insulation on a wire feeding speed switch EG-19-SS had been broken, causing an intermittent short. While identifying this problem, a different wire was identified that had been pinched that had to be replaced. According to drawings the wire was # 12 AWG, but the technicians identified the wire in the field to be # 14 AWG. Delays were caused while engineering researched and found that the correct wire was # 14 AWG. Revisions to the drawing were submitted.

Other problems were encountered during the performance of the maintenance and modifications. Jacket coolant was refilled using one section of the operations procedure before it was realized that a new section existed for filling the system with corrosion and biological inhibitors.

A leaking instrument tube line was identified on February 1, 1997, during post installation testing of the MAR. The leak appeared to be colored water, which indicated that it was jacket coolant water. The leak was not isolable and necessitated repairs prior to restoring the diesel to functional status.

On February 1, 1997, after repairs were completed to the leaking instrument tubing, the EDG was run for the MAR functional test and post maintenance testing. The following day, on February 2, 1997, it was identified that several post maintenance test (PMT) packages on EDG-1A had been omitted during the diesel run of the previous day. Pcs 97-723, 97-757, and 97-755 were written to document several missed PMTs on the EDG-1A.

On February 3, 1997, PC 97-895 was written to document missed PMTs on maintenance on RWP-2A and RWV-38. The licensee's apparent cause evaluation on all of these missed PMTs revealed that they had all been scheduled to be completed on January 31, 1997. When work delays prevented the completion of the PMTs on that day, no mechanism existed to maintain the tasks on the schedule or to place the tasks on the following week's schedule. All of the PMTs were rescheduled and were successfully completed. The lack of a mechanism to recognize uncompleted tasks and maintain them on the schedule was identified as a weakness.

On February 5, 1997, the inspectors attended a post job critique for the EDG-1A maintenance and modifications. It was identified at this meeting that there was no assigned person responsible to coordinate all of the various tasks. Factors contributing to the problems encountered included the weakness discussed above in the scheduling process, too few

people prepared and briefed for the tasks to relieve personnel dedicated to performing the tasks, and a lack of a coordinated review of work packages prior to issuance. The lack of a responsible individual to coordinate the task has been a recurring issue at the site.

c. Conclusions

Problems were encountered throughout the performance of the EDG-1A outage. Lack of coordination was identified as a key contributor. A weakness was identified for the absence of a mechanism to ensure that tasks scheduled for the weekend that were not completed were rescheduled for the subsequent week.

M1.4 Improper Documentation of Test Instrument Connections

a. Inspection Scope (62707)

As part of the installation of MAR 96-10-05-01 on EDG-1A, a Dranetz data acquisition system was installed to perform post modification testing and future testing. During review of the post installation work package, the licensee discovered that the documentation for the installation had not been completed by the relay technician.

b. Observations and Findings

PC 97-738 was written on February 3, 1997, to identify this failure to document the completion of the work. The apparent cause determination that the licensee made determined that poor communications between the project manager and the relay technician had not clearly identified the need to complete the documentation.

The inspectors interviewed the project manager and reviewed the installed system data from the previous diesel test runs. The data were within the expected range. Discussions with the licensee revealed that, if the system had been connected incorrectly, no data would have been received. The relay technicians routinely installed this equipment at both the nuclear site and at the fossil units. According to the licensee, this was normally considered within the skill-of-the-craft for relay technicians. The instructions were developed for electrical maintenance and I&C technicians, who do not normally install these instruments, by the technician who performed the installation.

c. Conclusions

As a result of the incomplete documentation for a MAR package completion, the need for better communications has been identified by the licensee. The test instrument has been verified to have been properly installed. No further actions are required.

M1.5 Testing of Toxic Gas Chlorine Monitors

a. Inspection Scope (61726, 37551)

The licensee has proactively been performing testing on a station constructed to reproduce the installed toxic gas chlorine monitor. This initiative was taken in an effort to increase reliability of the installed system. The inspectors have been monitoring these tests, witnessing the efforts of the engineering staff conducting the tests.

b. Observations and Findings

Testing revealed a lack of repeatability for time response testing of the system. The acceptance criteria was 15 seconds from receipt of the chlorine at the remote sensor until completion of the control room emergency ventilation system switching to recirculation mode. Normally, per PT-366, Toxic Gas Detection System Calibration (Train A) and PT-367, Toxic Gas Detection System Calibration (Train B), time response testing is performed immediately following span testing, which supplies chlorine test gas to the sensor. On February 10, 1997, the licensee performed the span test but elected to wait until the next day to perform the response time test and to evaluate the effect of not having put chlorine gas previously on the sensor. This was the condition that would exist on a valid chlorine gas actuation. Without the span test being performed immediately prior to performing the response time test, the response time test failed.

Further tests revealed that when the sensor was exposed to chlorine prior to the response time test, the response times were reduced. PC 97-978 was written on February 12, 1997, to document that the toxic gas chlorine monitors may need to be exposed to chlorine for an unknown period of time before they can respond fast enough to pass the 15 second acceptance criteria. By performing the span test prior to the response time test, the system was preconditioned to pass the response time test.

As a result, the licensee declared both trains of chlorine monitors inoperable and placed the control room emergency ventilation system in the recirculation mode. The licensee was evaluating installed designs at other licensee's facilities in an attempt to identify a reliable design. The licensee indicated a plan to install a reliable system prior to restart from the current outage.

Technical Specification 5.6.1.1 requires, in part, that procedures be developed and implemented covering activities as recommended in Regulatory Guide 1.33, Appendix A, Revision 2 of February 1978. Among these are surveillance procedures for each surveillance test listed in the technical specifications. The design basis, as defined in the Final Safety Analysis Report (FSAR), Section 9.7.3.1, for the Control Room Emergency Ventilation System (CREVS), included two trains of toxic gas chlorine monitors which were to be operable at all times. This was to allow the system to maintain control room habitability during a toxic gas release. Technical Specification Surveillance Requirement 3.7.12.3

required that the licensee verify each CREVS train actuates to the emergency recirculation mode on an actual or simulated actuation signal, at least once per 24 months.

c. Conclusions

The inadequate procedure, which allowed the preconditioning of the chlorine sensor, prevented an accurate response time test from being performed. The licensee took prompt corrective actions by declaring the toxic gas monitors inoperable and placing the CREVS in the recirculation mode. The licensee was actively pursuing long term corrective actions by working with the sensor manufacturer and consulting engineers. This licensee identified violation meets the requirements outlined in Section VII of the Enforcement Policy and will not be cited. This issue is identified as Non-Cited Violation NCV 50-302/97-01-05, Inadequate Surveillance Procedure to Test Operability of the Toxic Gas Chlorine Detectors.

M1.6 Scheduling of Work on Non-Nuclear Instrumentation

a. Inspection Scope (62707)

On February 4, 1997, the licensee identified that the weekly work schedule had clearances being placed on the pressure transmitter isolation valves for Instruments RC-132-PT and RC-131-PT1.

b. Observations and Findings

Work packages were taken to the main control room for approval to begin work. The operations SSOD identified that neither the work packages (WR NU 0337967 for RC-131-PT1 and WR NU 0337968 for RC-132-PT) nor the schedule provided any indication or recognition that the transmitters provide input signals to the Power Operated Relief Valves (PORVs) and the Decay Heat drop line auto closure initiation. The PORV is required to be operable in modes 1, 2 and 3. The Auto Close Initiation system is required to be operable in modes 1, 2, 3 and 4. In the present plant mode, neither system was required to be operable. However, this was not clear on the work request packages, and no evaluation had been completed for the impact of removing these instruments from service. The SSOD refused to authorize the work packages until a full evaluation of the impact of the isolation of the instruments had been completed.

c. Conclusions

Scheduling of work packages which do not identify the impact on plant conditions and provided work packages to the field operators who do not recognize the impact of the task is a recurring problem. This is identified as a weakness in the implementation of the work planning program.

M1.7 Unplanned Alarm During Instrumentation and Controls Work

a. Inspection Scope (62707)

On February 3, 1997, an annunciator alarm was received in the main control room for feedwater control valve air failure. At the time of the incident, the unit was in mode 5, and feedwater was not in operation. The alarm was not expected as the result of any work in progress. At the time the alarm was received, the inspector was in the control room and witnessed the licensee's response.

b. Observations and Findings

Investigation revealed that I&C technicians were performing work on FWV-39, which caused the alarms. It was confirmed that the operations work controls supervisor was aware of the work in progress, but he was not aware of any expected alarms. The inspector questioned the I&C technicians. They were not aware that the alarm would result from the task they were performing and the WR did not indicate that an alarm would be received.

c. Conclusions

Several events contributed to the operators not being aware that an alarm might be received. Although the work controls supervisor was aware of the work in progress, the operations shift was not. The lack of indication on the work package contributed to the confusion. The inspectors identified that even though the mechanisms exist to include warnings about these observed problems in the work packages, the lessons learned are rarely considered when planning a work package. Instead, the process relies on the technicians and operations review to identify problems. This lack of thorough evaluation is another example of the weakness in the implementation of the work planning program identified in paragraph M1.6.

M8 Miscellaneous Maintenance Issues

M8.1 (Open) URI 50-302/96-17-03, Failure to Conduct Required Technical Specification Surveillance Testing on Safety Related Circuitry

a. Inspection Scope (37551, 92902)

On January 31, 1997, the licensee identified that test deficiencies existed in licensee Procedures SP-907A, Monthly Functional Test of 4160V ES Bus "A" Undervoltage and Degraded Grid Relaying, and SP-907B, Monthly Functional Test of 4160V ES Bus "B" Undervoltage and Degraded Grid Relaying.

b. Observations and Findings

The test deficiency identified that contacts in all three channels of the first level undervoltage relays (FLUR) and second level undervoltage

relays (SLUR) were not being tested in accordance with the TS requirements. The FLUR and SLUR relay contacts were subsequently tested satisfactorily in accordance with the TS. This issue is identified as an additional example of URI 50-302/96-17-03, Failure to Conduct Required Technical Specification Surveillance Testing on Safety Related Circuitry, pending completion of the licensee's review under Generic Letter (GL) 96-01.

c. Conclusions

No further actions are required at this time. URI 50-302/96-17-03 remains open pending completion of the licensee's GL 96-01 review and the inspectors' assessment of the findings.

III. Engineering

E1 Conduct of Engineering

E1.1 General Comments (37551)

The inspectors reviewed various Engineering and support activities which included presentations to licensee management on January 31, 1997, and February 11, 1997, by the Emergency Diesel Generator (EDG) and Emergency Feedwater (EFW) Interim Fix Option Team. The team was chartered to assess the feasibility of starting the plant up with the interim 150 Kw load upgrade but prior to the planned long term larger upgrade of the EDG capacity. The inspector observed that this was a multi-disciplined team, which took a conservative and questioning approach to the design basis challenges that must be resolved before those systems would be acceptable for restart. The inspector concluded the team was being very realistic and appropriately involved Framatome vendor support to address design issues.

The inspectors also reviewed activities associated with resolution of corroded primary valve seats and difficulties in obtaining an effective vent of decay heat system piping. Engineering personnel provided good support for the remainder of the reviewed or witnessed activities. Activities were found to be adequate, well controlled, and documentation usually provided sufficient detail and appeared technically adequate. Additional details regarding notable issues are described below.

E1.2 Non-Safety Related Components in Safety Related Applications

a. Inspection Scope (37551, 92903)

The inspectors reviewed the licensee's investigation and corrective actions for an issue identified where non-safety related components were used in a safety related application.

b. Observations and Findings

During a review of the licensee's 10 CFR 50 Appendix R program, the licensee identified a need for voltage protection on current transformers (CTs) installed on several systems. The decision was made to review MAR 77-07-01-14, which was installed in 1985 as a part of the Appendix R upgrade. The secondary protection installed as part of this MAR protected the CTs which provided remote indication of amps, vars, and kilowatts for the EDGs in the main control room. During the review, the engineer identified that these protection devices were neither seismically qualified nor procured as safety related.

PC 97-0050 was issued on January 9, 1997, to document this finding. At that time, the EDGs were evaluated to be conditionally operable/potentially inoperable, pending the final review of the impact of the non-safety related devices being installed. This was based on the assumption that in mode 5, loading would be greatly reduced and load management (which requires the kilowatt indication) would not be necessary.

On January 21, 1997, it was identified that although the load demands in mode 5 would be low, the controlling procedure for a load management during a loss of offsite power (LOOP) event would be AP-770, Emergency Diesel Generator Actuation. This procedure did not address the reduced load demands and could lead to overloading the diesel generators, if no kilowatt indication was available. The shift supervisor declared both diesel generators inoperable and entered TS action statement 3.8.3. EDG-1A was already inoperable for preplanned maintenance and modifications.

The licensee continued evaluating the devices while the Operability Concerns Resolution (OCR) was completed. A spare protector was disassembled and inspected. The device is a thyrite type of device which prevents voltage surges which could damage circuitry. The device was also supplied to an independent contractor for evaluation.

The contractor concluded that the device would perform its intended function both during and following a seismic event. The licensee issued the completed OCR on January 26, 1997, and concluded that the diesels were operable, but degraded. EDG-1B was declared operable, but EDG-1A remained inoperable pending completion of the ongoing diesel outage.

The licensee is currently evaluating replacement protectors and the necessary requirements to upgrade the existing protectors to safety related.

In a second example during preparation to replace MUV-103, the Engineered Safeguards (ES) isolation valve between the makeup system and the Reactor Coolant Bleed Tanks (RCBT), the boric acid storage tanks (BAST), and the demineralized water supply, the licensee discovered that the installed operator and controller for this safety related valve were non-safety related. In the licensee's accident analysis, this valve was

assumed to isolate for a moderator dilution event. With the non-safety related components installed, this valve cannot be assured to operate when required. The licensee plans to replace this valve prior to restoring the makeup system and has added it to their restart restraint list.

c. Conclusions

The inspectors concluded that these problems were further examples of inadequate design control. The licensee has taken the necessary immediate corrective actions and has added final resolution of these issues to the restart restraint list. This licensee identified violation meets the requirements outlined in Section VII.B. of the Enforcement Policy and will not be cited. This issue is identified as Non-Cited Violation NCV 50-302/97-01-10, Inadequate Design Control, Non-Safety Related Components in Safety Related Applications - Two Examples: Thyrite Surge Protection Device, Operator and Controller for MUV-103.

E1.3 HPI System Modifications to Improve SBLOCA Margins

a. Inspection Scope (37550)

In a letter to the NRC dated October 28, 1996, the licensee described eight design issues that would be addressed prior to restarting the plant. Design Issue 2, high pressure injection (HPI) system modifications to improve small break loss of coolant accident (SBLOCA) margins, described improving design margins in the HPI system by adding flow limiting venturries and crossover piping. However, the licensee stated that these modifications would not be made prior to restart because the HPI system currently met its design and licensing basis. During this inspection, the inspector reviewed some aspects of the HPI system to verify that it did currently meet its design and licensing basis.

b. Observations and Findings

(1) Peak Cladding Temperature Exceeding 2300 Degrees F

The inspector reviewed the Final Safety Analysis Report (FSAR), paragraph 6.1.1, Emergency Core Cooling System (ECCS) Design Bases, and noted the following statements:

"Assuming the loss of one core flood tank (CFT) and using the ground rules specified in Part 4 of Appendix A of the Interim Acceptance Criteria (where the CFT water is assumed to be lost after the end of blowdown), the 8.55 square foot cold leg split results in a cladding temperature rise exceeding 2300 degrees F because of the long adiabatic heatup period. The above case assumes the loss of one CFT coincident with the failure of a diesel. This amounts to a simultaneous active and passive failure. If only the passive failure was considered, that is, credit was taken

for both low pressure injection (LPI) and high pressure injection (HPI) pumps, the cladding temperature could be held below 2140 degrees F if expected rather than design peaks are employed."

The inspector's concern with these statements was that they were not consistent with the current design requirements. 10 CFR 50.46, Acceptance Criteria for Emergency Core Cooling Systems (ECCS) for Light Water Nuclear Power Reactors, requires that the peak cladding temperature (PCT) shall not exceed 2200 degrees F for all design basis events. Also, 10 CFR 50, Appendix A, General Design Criteria for Nuclear Power Plants, requires that plants be designed against an initiating event (i.e., a break in a core flood tank line) concurrent with a single failure (i.e., failure of a diesel generator). However, the above FSAR statements indicated that, for such a design basis event, the PCT could exceed 2300 degrees F.

The inspector informed the licensee of this concern, and subsequent licensee and inspector review of design and licensing information revealed that the FSAR statements were incorrect. Supplement No. 4 to the Safety Evaluation Report by the Office of Nuclear Reactor Regulation, dated January 28, 1977, stated that Babcock and Wilcox had provided revised ECCS performance calculations for the worst case break using the revised evaluation model which demonstrated that the PCT and the percent of local and core-wide metal-water reaction remained below the limits specified in 10 CFR 50.46. Supplement 4 further concluded that the analysis of the ECCS performance conformed to the acceptance criteria in 10 CFR 50.46. The inspector verified that the Babcock and Wilcox revised ECCS performance calculations (BAW-10103, Rev. 3, Topical Report of 1977) did conclude that the worst case LOCA was an 8.55 square foot cold leg split, which resulted in a PCT of less than 2200 degrees F. Further, BAW-10103 calculations did include failure of a diesel generator concurrent with the LOCA.

Based on the results of this review, the licensee initiated a change to correct the FSAR. The inspector verified that the incorrect statements had been in the FSAR since 1973, prior to plant licensing. The inspector also verified that the licensee initiated PC 97-0784 on January 30, 1997, to address the error in the FSAR. Since the error was an old design issue in the original FSAR that was reviewed by the NRC prior to licensing of the plant, and the licensee promptly initiated corrective actions, the inspector concluded that enforcement action for this FSAR error was not warranted.

(2) Required Operator Actions for SBLOCA Mitigation(a) FSAR Revision 23 Increased the Number of Required Operator Actions

The inspector reviewed FSAR paragraph 6.1.3.1.1, Design Evaluation of the HPI System for RCS Cold Leg Small Break LOCA; FSAR paragraph 6.1.3.1.2, HPI Line Break Small Break LOCA; and FSAR paragraph 14.2.2.5.7, Small Break LOCA; and noted that changes recently made, in Rev. 23, included:

Rev. 23 added two required operator actions to mitigate a SBLOCA event concurrent with the failure of an EDG. It described the following required operator actions:

- (i) Within 10 minutes after event initiation, the operator must select an alternate power supply and open two injection valves. This operator action was in the previous FSAR revision.
- (ii) Within 20 minutes after event initiation, the operator must isolate normal makeup flow and also isolate RCP seal injection flow. These two operator actions were not in the previous FSAR revision.

Rev. 23 added a required operator action to isolate an HPI injection line that was broken (with flow substantially higher than the other injection lines). The previous FSAR revision included a required operator action to balance flows in the HPI injection lines - that operator action was replaced by the new required action of isolating an injection line that was broken.

Also, Rev. 23 added a required operator action in the event of a LOCA in the letdown line, when the operator would be required to isolate letdown flow. This operator action was not in the previous FSAR revision.

FSAR Rev. 23 also stated that HPI flow to the core during the first 10 minutes after event initiation (with concurrent failure of an EDG) would be only 36% of the total HPI flow. After the operator opened the two remaining injection valves, HPI flow to the core would increase to a greater percentage of total HPI flow. The previous FSAR revision stated that HPI flow to the reactor must be the equivalent of 70% of the flow of one HPI pump, and that would be achieved by four injection lines with one HPI pump.

The inspector concluded that FSAR Rev. 23 increased the number of required operator actions for SBLOCA mitigation (from two to five). Also, Rev. 23 described a reduced

amount of HPI flow to the reactor, higher peak clad temperatures, and higher offsite doses.

(b) HPI Licensing Basis in 1979 Included One Operator Action

The inspector reviewed licensing information, which included various letters between the licensee and the NRC leading to an NRC Safety Evaluation, dated May 29, 1979. The Safety Evaluation concluded that the licensee's small break LOCA analysis and ECCS design were in conformance with the requirements of 10 CFR 50.46 and noted that the design included an operator action to initiate HPI to two injection lines within 10 minutes. In addition, the Safety Evaluation stated that the operator action will provide a minimum of four injection lines and one HPI pump, which will provide at least the 70% of the flow of one pump to the reactor that the licensee determined was needed. The Safety Evaluation also stated that all three HPI pumps are automatically started when the ES signal is actuated. (The licensee's current design included starting only two HPI pumps on an ES signal.) In a previous licensee letter on ECCS Small Breaks Analysis dated February 28, 1979, the licensee stated that operator actions to isolate normal makeup or RCP seal injection were not needed, because the normal makeup is isolated automatically on an ES signal and without isolating RCP seal injection more than 70% of the flow from one HPI pump is available as injection into the RCS. In a letter dated October 9, 1978, the licensee stated that analyses were being performed to determine if operator action was needed to balance the HPI flow in the injection lines and that if balancing was required, then the licensee would install flow limiters to preclude the need for such operator action. In another letter dated November 7, 1978, the licensee stated that the analyses showed that no operator action was needed for flow balancing in the HPI injection lines. In summary, the NRC had licensed the licensee's ECCS system design with provision for one operator action within 10 minutes which would ensure at least 70% of the flow of one HPI pump to the reactor.

The inspector concluded that the licensing basis from 1979 included only one required operator action for SBLOCA mitigation.

(c) SBLOCA Calculation in 1996 Included Seven Operator Actions

The inspector reviewed the licensee's current calculation for Small Break LOCAs, M96-0032, Reevaluation of HPI Requirements During Small Break LOCAs, dated May 2, 1996. This calculation was also identified as Framatome Technologies Incorporated (FTI) calculation 51-1245866-00. The calculation stated that seven operator actions were

required to mitigate the spectrum of small break LOCAs: 1) trip all running RCPs within two minutes, 2) initiate HPI flow through all four injection lines within 10 minutes, 3) isolate letdown within 10 minutes, 4) isolate RCP seal injection within 20 minutes, 5) isolate normal makeup within 20 minutes, 6) ensure adequate HPI flow within 20 minutes, and 7) ensure adequate EFW flow within 20 minutes. The calculation also stated that during the performance of the hydraulic analyses, FTI discovered that the HPI flows provided by the licensee's system were less than the HPI flows used in the FTI analysis of record for cold leg pump discharge breaks. This flow deficit was primarily due to the generic B&W plant modeling assumptions in the FTI analysis of record (i.e., normal makeup and RCP seal injection automatically isolated on ESAS) and not accounting for the time delay involved in the licensee's operator actions to manually isolate normal makeup and RCP seal injection.

The inspector concluded that the SBLOCA calculation of 1996 included seven required operator actions for SBLOCA mitigation.

The seven required operator actions in the 1996 calculation were more than the one required operator action in the 1979 licensing basis. The seven were also more than the five required operator actions in the recent FSAR Rev. 23 and more than the two required operator actions in the previous FSAR revision. The inspector noted that the increase in required operator actions may represent a potential increase in the probability of occurrence of a malfunction of equipment important to safety and therefore, per 10 CFR 50.59, prior NRC review and approval would be required. However, the inspector considered that further review of this issue was needed to determine if any of the added operator actions had been reviewed and approved by the NRC between 1979 and 1996. In addition, inspector review was needed of any procedure, plant design, or FSAR changes (and related 50.59 safety evaluations) that added required operator actions or deleted automatic actions. This issue is identified as the first example of URI 50-302/97-01-06, HPI System Design, Licensing Basis, and TS Concerns.

(3) HPI Design Not Consistent With Licensing Basis

The inspector noted that Calculation M96-0032 identified a design control error with the HPI system. It stated that the licensee's licensing submittals on HPI system design and SBLOCA in 1978 and 1979 (and the NRC SER in 1979) incorrectly assumed that normal makeup and RCP seal injection were automatically isolated at Crystal River 3. (The 1979 B&W SBLOCA calculation, on which CR3 relied, assumed that normal makeup and RCP seal injection were automatically isolated based on a generic B&W plant.) However, the CR3 design did not include automatic isolation of normal

makeup and RCP seal injection. Consequently, the CR3 design would supply less HPI flow to the reactor than assumed in the 1979 B&W SBLOCA calculation. Calculation M96-0032 stated that isolation of normal makeup and seal injection was necessary to keep peak clad temperatures for a design basis SBLOCA below 2200 degrees F. The inspector concluded that the CR3 HPI system was apparently outside its licensing basis from 1979 through 1997. The inspector also considered that further review was needed of the consequent impact on HPI system operability during the period of 1979 through 1997 (including what operator actions were included in EOPs). This issue is identified as the second example of URI 50-302/97-01-06, HPI System Design, Licensing Basis, and TS Concerns.

(4) HPI Design Not Consistent With TS

The inspector noted that the CR3 TS included LCO allowable outage times for one train of HPI but included no allowable outage time for both trains of HPI. However, the CR3 HPI system design included several motor operated valves that were in both trains of HPI (i.e.; MUV-3 and MUV-9, HPI pump discharge crosstie valves; MUV-23, MUV-24, MUV-25, and MUV-26, HPI injection valves; and MUV-27, normal makeup valve). All of these valves had required surveillances (i.e., quarterly stroke time tests) and maintenance (i.e., gearbox & grease inspection). Initial inspector review indicated that the licensee may have performed some of these surveillance or maintenance activities while the HPI system was required to be operable. The inspector considered that further review was needed to determine when these valves were out of service for surveillance testing or maintenance with the plant in Mode 4 or above during the last three years, and in each case how TS compliance was affected. This issue is identified as the third example of URI 50-302/97-01-06, HPI System Design, Licensing Basis, and TS Concerns.

(5) Licensee Design Bases and FSAR Reviews Did Not Identify These Issues

As part of the licensee's extent of condition review for design problems, the licensee was constructing time lines for selected safety systems. The time lines would, for example, review changes to the systems from the initial licensing basis (i.e.; modifications, operating procedure changes, licensing basis changes, FSAR changes, TS changes) to assure that the licensing and design bases had been maintained.

The inspector reviewed the licensee's time line for the makeup/HPI system that had been completed on February 10, 1997, and noted that the time line identified a number of good questions and potential issues. However, the time line did not identify any of the issues raised by the inspector in URI 50-302/97-01-06, HPI System Design, Licensing Basis, and TS Concerns.

The inspector also noted that the licensee's current FSAR review project had not identified the above FSAR error (regarding peak cladding temperature exceeding 2300 degrees F). The licensee's FSAR reviewer stated that the review was focused on verifying that FSAR information was implemented in operating, surveillance, and maintenance procedures; system DBDs; and TS. However, the review basically assumed that information in the FSAR was correct. The reviewer stated that, therefore, the FSAR review would not have been expected to identify such errors in the FSAR.

c. Conclusions

An unresolved item was identified regarding the design of the HPI system: URI 50-302/97-01-06, HPI System Design, Licensing Basis, and TS Concerns. Inspector concerns included the following.

- Since 1996, seven operator actions were identified for SBLOCA mitigation; however, the licensing basis since 1979 contained only one operator action.
- Prior to 1996, the licensee's SBLOCA analysis incorrectly assumed that RCP seal injection and normal makeup were automatically isolated.
- The effect on system operability was not assessed with both HPI trains sharing several active components.

In addition, the inspector noted that the licensee's recently completed extent of condition review (time line) for the makeup/HPI system design did not identify any of the inspector's concerns.

An error in the FSAR was identified, where the FSAR stated incorrectly that for a design basis accident the peak cladding temperature would exceed 2300 degrees F (the regulatory limit is 2200 degrees F). In addition, the inspector noted that the licensee's current FSAR review project had not identified this FSAR error.

Since this issue was left as an unresolved item, with more inspection needed to reach conclusions, the inspector did not at this time assess the licensee's performance with respect to this issue in the five NRC continuing areas of concern.

E1.4 10 CFR 50.59 Safety Evaluations

a. Inspection Scope (37550)

The inspectors reviewed 10 CFR 50.59 safety evaluations for recent engineering products to assess their adequacy.

b. Observations and Findings

The inspectors reviewed 10 CFR 50.59 evaluations for one modification, MAR 96-10-04-01, Installation of Overpressure Protection for Isolated Piping Sections (GL 96-06), dated January 3, 1997; and for one design basis document change, EDBD TC No. 536, HPI Flows and BWST Circulation, dated January 16, 1997; and assessed both as adequate, thorough, and detailed. The inspectors also reviewed the 10 CFR 50.59 evaluation for an FSAR change, FSAR Table 6-1 Correction, dated January 24, 1997, which involved core flood tank level and pressure; and noted that it lacked sufficient clarity and detail to make a determination on acceptability. Overall, the inspectors noted improvement in the quality of the recent 50.59 safety evaluations reviewed over those of one - two years ago.

The inspectors reviewed a 10 CFR 50.59 screening for MAR 94-09-02-01, DC Cooling Instrument Enhancements, dated June 27, 1996, which involved non-safety instrument air to DCV-7, 18, 177, and 178. The inspectors assessed this 10 CFR 50.59 screening as having a lack of sufficient detail to support the conclusion that a full 10 CFR 50.59 safety evaluation was not required.

c. Conclusions

The inspectors reviewed a small sample of 10 CFR 50.59 safety evaluations for engineering products and noted improvement in the quality and thoroughness over those generated one - two years ago. However, the sample size was small and therefore, further review will be needed to verify adequacy of the overall 10 CFR 50.59 program.

The inspector assessed the licensee's performance, with respect to this issue, in the five NRC continuing areas of concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - N/A

E1.5 Decay Heat Valve (DHV) 21 Operability Evaluation

a. Inspection Scope (37551)

The inspectors reviewed the licensee's investigation and disposition of internal corrosion found on DHV-21, the pump inlet manual isolation valve for decay heat pump (DHP) 1A.

b. Observations and Findings

The licensee discovered significant seat leakage while draining DHP-1A for maintenance on January 20, 1997. Upon disassembly the licensee observed severe localized corrosion of the seat rings that were determined to be made of carbon steel. Vendor drawings for the valve

indicated that the seat rings should be constructed of 316 stainless steel, the correct material for this primary system application. The licensee appropriately generated precursor card (PC) 97-0472 to implement corrective action and identified 3 other identical valves that were used in the plant. DHV-32, the inlet isolation valve to DHP-1B, was used in January, 1997, as a boundary valve for pump work and had not exhibited any seat leakage. The other two valves, DHV-39 and 40, which are the pump suction valves on the lines from the reactor coolant system, were also verified to be seating properly during recent maintenance evolutions. The licensee was confident that the seats in these valves were stainless steel based on this performance, but they still plan to inspect DHV-32 as a precautionary measure during the B train emergency systems outage scheduled for the week of March 10, 1997. The licensee was unable to procure a replacement valve for DHV-21 from the vendor quickly, and the corrosion damage coupled with high local radiation dose rates made repair unfeasible. Consequently, the licensee initiated an Operability Concerns Resolution document to investigate whether the DH system could be considered operable with the valve reassembled and the seating surface removed. The licensee removed all loose seat material and corrosion products to ensure they were not entrained into the RCS and reassembled the valve. The investigation revealed the valve was not required to close for any safety function, so its inability to close was acceptable until a permanent repair or replacement option could be determined. The inspector observed that the licensee's primary consideration was restoring the out of service decay heat removal train in order to reestablish two redundant methods of decay heat removal. The inspector reviewed the licensee's 10 CFR 50.59 assessment and safety evaluation and did not identify any deficiencies. Identification of a permanent fix was still pending at the end of the report period.

c. Conclusion

The inspector concluded the licensee displayed an appropriate priority to restore a second decay heat removal system to service and performed a thorough and conservative analysis to justify the decision to leave an inoperable manual valve in the system and evaluate extent of condition.

The inspector assessed the licensee's performance, with respect to this issue, in the five NRC continuing areas of concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - N/A

E1.6 Evaluation of Dranetz Test Instrument Inaccuracies on Emergency Diesel Generator Testing

a. Inspection Scope (37551)

The inspectors reviewed the licensee's investigation and disposition of EDG test instrument inaccuracies contained in Operability Concerns Resolution (OCR) Report EG-97-EDG-1A/1B and interviewed licensee Technical Support Engineering managers and engineers.

b. Observations and Findings

The OCR was primarily concerned with whether the EDGs exceeding maximum load limits during full load testing and if they satisfied the surveillance requirements (SR). SR 3.8.1.11 requires a maximum load test at a load between 3100 and 3250 kw be performed every 24 months. This test was last done in April, 1996, on both EDGs using the Dranetz test instrumentation. However, instrument error from the Dranetz was not factored in to the testing, and consequently the testing bands were identical to the SR band of 3100 to 3250 kw. This oversight was discovered by a licensee engineer in January, 1997, while preparing a post-modification test to support corrective actions to upgrade EDG capacity. The engineer questioned why the normal load test in Surveillance Procedure (SP) 354A/B had a narrower test band to account for instrument error while the maximum load test did not. Based on this concern, the licensee initiated the OCR and performed a calculation and testing to determine the reliable accuracy of the Dranetz instrumentation. The OCR investigation was complete on February, 19, and revealed that a calculated error of +/- 54 kw was necessary to be applied to the April, 1996, testing. After review of the testing data, the licensee determined that the worst case low (logged reading minus 54 Kw) results for both EDG A and B were intermittently below the lower testing limit of 3100 Kw. The licensee conservatively determined the EDGs were previously inoperable because they had not fulfilled the requirements of SR 3.8.1.11 and that a Licensee Event Report (LER) per 10 CFR 50.73 was required. The A EDG had been tested satisfactorily in January, 1997, with revised Dranetz limits so it remained operable. The "B" EDG was scheduled to be tested the weekend of February, 22, to restore its operability. The OCR and calculation developed an improved Dranetz inaccuracy of +/- 38 Kw based on a different test probe that was used for this subsequent testing.

The OCR also determined that the worst case high (logged reading plus 54 Kw) results for both EDG A and B were intermittently above the upper testing limit of 3250 Kw which also corresponds to the EDG 30 minute rating. They determined EDG A had potentially exceeded the limit for 6 minutes and EDG B had for 15 minutes during the April, 1996, testing. The OCR contained a detailed justification for continued operation in Mode 5 that assessed the potential degradation this would have on the ability of the EDG to accomplish its function. The inspector reviewed this justification, found it very detailed, and did not identify any problems with the licensee's conclusions that the EDGs were operable for

Mode 5 loading with the given portion of the 30 minute rating used. The licensee plans to perform outage inspections of both EDGs during their current outage which will reset the 30 minute ratings to a full 30 minutes.

c. Conclusions

The inspectors were concerned that the EDGs were potentially inoperable since the last refueling outage in 1996. However, the problem was found by the licensee while developing a functional test which was corrective action for a previously cited problem with EDG loading capacity. Corrective action since discovery has been timely and EDG A has already been retested. The inspector concluded the OCR involved large amount of detailed and thorough engineering work and provided a well defined plan that had operations staff involvement. Therefore, this issue is considered an example of a problem found as corrective action for a previous problem.

The inspector assessed the licensee's performance, with respect to this issue, in the five NRC continuing areas of concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - Good

E2 **Engineering Support of Facilities and Equipment**

E2.1 Corrective Action and Reportability Issues

a. Inspection Scope (92903)

The NRC had identified a number of concerns with corrective action and reportability as noted in apparent violations EEI 50-302/96-12-03 and EEI 50-302/96-19-02. As part of the followup for these issues, the inspectors reviewed the licensee's recently issued corrective action Procedure CP-111, Processing of Precursor Cards for Corrective Action Program, Revision 55, relative to the definition of a DBI as defined in the procedure.

b. Observations and Findings

The definition of a DBI was detailed in paragraphs 3.1.3 and 3.1.4 of Procedure CP-111. The definition given was the same as that in Procedure CP-150, Identifying and Processing Operability Concerns and Procedure CP-151, External Reporting Requirements.

The definition, as written in the above procedures, equated a DBI with operating outside the design basis as referenced in 10 CFR 50.72 and 10 CFR 50.73 and indicated that a DBI exists only if a system, structure, or component (SSC) is unable to perform its safety function in

preventing or mitigating design basis events. The inspectors pointed out that this definition appeared to be narrow, considering the definition of design basis given in 10 CFR 50.2 and the requirements of 10 CFR 50, Appendix B, Criterion III, relative to design control. When questioned by the inspectors, the Manager, Nuclear Licensing stated that the definition was not meant to be that narrow, but he could see how it could be interpreted that way. He stated that the definition would be revised to state more clearly what was intended.

c. Conclusions

The definition of a DBI, as defined in Procedures CP-111, CP-150, and CP-151 was not broad enough to ensure that the requirements of 10 CFR 50, Appendix B, Criterion III, 10 CFR 50.72 and 10 CFR 50.73 would be met. The licensee agreed the definition did not clearly state their intent and stated that procedures would be revised to clarify their intent.

The inspector assessed the licensee's performance, with respect to this issue, in the five NRC continuing areas of concern:

- Management Oversight - Adequate
- Engineering Effectiveness - N/A
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Adequate
- Operator Performance - N/A

E8.1 (Closed) VIO 50-302/96-05-05, Failure to Follow Procedures for Updating Design Basis Documents (DBDs)

a. Inspection Scope (92903)

This issue involved failure to issue a Temporary Change (TC) to the Enhanced Design Basis Document (EDBD) and failure to ensure that TCs to the EDBD were incorporated into the EDBD as required by procedures. The licensee's letter of response dated August 12, 1996, was reviewed and found acceptable. The inspectors reviewed the licensee's corrective actions as detailed in paragraph b. below.

b. Observations and Findings

This violation was issued for two examples of failure to follow procedures for updating the EDBD. In one example, a TC to the Makeup System EDBD was not issued when a plant modification changed the Hydrogen Addition Pressure Regulator setting from 10 psig to 19.5 psig. In the other example, the 12 month review of the EDBDs had not been performed and documented, resulting in DBD Tcs not being incorporated within the required two year time.

Licensee corrective actions were documented in Problem Report (PR) 96-0230. The inspectors verified licensee corrective actions by reviewing the following documents:

- Completed PR 96-0230.
- Temporary Change 487 to the EDBD - which properly documented the Hydrogen Addition Pressure Regulator setting.
- Revision 7 of NEP Procedure 216, Plant Design Basis Documents - which enhanced requirements for revising DBDs.
- Revision 9 of NEP Procedure 213, Design Analysis/Calculations - which required identification of plant documents affected by a change and tracking by the Nuclear Operations Tracking and Expediting System until incorporation into applicable plant documents.
- On the Job Training (OJT) Session Attendance Records - which documented review of the problem with applicable Design Engineers, Verification Engineers, Supervisors, and Configuration Management personnel.
- Documentation that incorporation of Tcs into the EDBD was up-to-date and that a system had been established to ensure that future TCs are incorporated on schedule.

c. Conclusions

The inspector determined that the licensee had identified the root causes and implemented adequate corrective actions. Based on the above review, Violation 50-302/96-05-05 is closed.

The inspector assessed the licensee's performance, with respect to this issue, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Good
- Operator Performance - N/A

E8.2 (Closed) VIO 50-302/96-05-07, Inadequate Receiving Inspections for Battery Chargers

(Closed) LER 96-12-02, Operation Outside Design Basis Caused by Battery Chargers Having Inadequate Test Results Accepted in Error

a. Inspection Scope (92700, 92903)

The inspector followed up on the licensee's corrective actions for this violation and LER.

b. Observations and Findings

The inspector verified that the licensee had completed all of the corrective actions stated in this LER and most of the corrective actions stated in the response to this Notice of Violation, including:

- Replacing the backup "swing" battery chargers DPBC-1E and DPBC-1F with new chargers.
- Incorporating additional guidance into the Nuclear Procurement and Storage Manual (NP&SM) for receipt inspectors' review of engineering software acceptability letters provided by engineering.
- Adding a requirement into the NP&SM for verifying that nameplate data complied with Purchase Requisition requirements.
- Distributing a copy of the related event report (LER 96-12-02), along with management's expectations, to design engineers, procurement engineers, and receipt inspectors.
- Updating the Preventive Maintenance Program to ensure that printed circuit cards and capacitors are replaced in the battery chargers on a five year frequency.

One corrective action, convening a Management Review Panel to further review the issue, had not been completed. The inspector found that this item and the third item above (verifying nameplate data) were not tracked by the licensee to assure they were accomplished. They were not in the licensee's corrective action system or the Nuclear Operations Tracking and Expediting System (NOTES). However, the licensee had recently made plans to have a review panel review the corrective actions for essentially all of the violations from 1996, including this one. This violation and LER are closed.

c. Conclusions

Violation 50-302/96-05-07, Inadequate Receiving Inspections for Battery Chargers; and LER 96-12-02, Operation Outside Design Basis Caused by Battery Chargers Having Inadequate Test Results Accepted in Error, are closed. The inspector noted, and commented to the licensee, that their tracking of corrective actions for violations was incomplete.

The inspector assessed the licensee's performance, with respect to this issue, in the five areas of continuing NRC concern:

- Management Oversight - Adequate
- Engineering Effectiveness - Adequate
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Adequate
- Operator Performance - N/A

E8.3 (Closed) VIO 50-302/96-05-08, Failure to Follow Purchasing Procedures for Inverters

a. Inspection Scope (92903)

The inspector followed up on the licensee's corrective actions for this violation.

b. Observations and Findings

The inspector verified that the licensee had completed the corrective actions for this violation, as stated in their response to the Notice of Violation, including:

- Requiring Nuclear Engineering Design personnel to read the related Problem Report and Nuclear Engineering Procedure 220.
- Requiring Buyers Associates to read the Nuclear Procurement and Storage Manual, Section 3.3.
- Processing a Procurement Requisition Amendment.
- Revising the associated mini-specification.

The inspector noted that the completion of all of these corrective actions was tracked and documented in the file for Problem Report 96-0187. This item is closed.

c. Conclusions

Violation 50-302/96-05-08, Failure to Follow Purchasing Procedures for Inverters, is closed. The inspector assessed the licensee's performance, with respect to this issue, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Good
- Operator Performance - N/A

E8.4 (Open) EA 95-16, Use of Nonconservative Trip Setpoints for Safety-Related Equipment

a. Inspection Scope (92903, 37500)

As part of the continuing review of corrective actions for EA 95-16, the inspectors reviewed several new instrument loop uncertainty setpoint calculations. In IR 95-06 the inspectors found that the only safety-related trip setpoint calculation completed did not follow the methodology specified in Instrument Society of America (ISA) 67.04, part II, as referenced by instrumentation and controls Design Criteria Instrument String Error/Setpoint Determination Methodology. To assess the progress the licensee had made in this area, the inspector reviewed a sample of the most recent instrument string error/setpoints.

b. Observations and Findings

Four recent instrument loop uncertainty (instrument string error) setpoint calculations were reviewed. These included:

- I-89-0013, Containment Air Temperature, Revision 6.
- I-95-0002, SW Pump Discharge Header Pressure Calculation, Revision 2
- I-95-0001, SW Heat Exchanger Outlet Temperature Error Calculation, Revision 2
- I-91-0004, Nuclear Service Closed Cycle Cooling Surge Tank Instrumentation Accuracies, Revision 3

These calculations were well documented, with well founded assumptions, and followed the methodology specified in ISA 67.04, Part II, as referenced by instrumentation and controls Design Criteria Instrument String Error/Setpoint Determination Methodology. These calculations were a significant improvement over calculations reviewed in IR 95-06.

The inspectors selected several instrument loop uncertainty setpoint calculations that included instrumentation in the Auxiliary Building to ensure the temperature assumptions used in design calculations for Instrument string error or loop uncertainty determinations were appropriately maintained. The instruments selected were:

<u>Instrument</u>	<u>Calculation</u>	<u>ESQPM Zone</u>	<u>Required Temperature</u>
SW-3-PI	M95-002	Zone 11	55 - 97° F
SW-123-TI	M95-001	Zone 12	65 - 97° F
SW-124-TI	M95-001	Zone 12	65 - 97° F
SW-125-TI	M95-001	Zone 12	65 - 97° F
SW-126-TI	M95-001	Zone 12	65 - 97° F
SW-139-LT	I91-004	Zone 11	55 - 97° F
SW-228-LT	I91-004	Zone 11	55 - 97° F

The inspector verified that the Environmental and Seismic Qualification Program Manual (ESQPM) environmental assumptions were used in the instrument loop uncertainty setpoint calculations.

The inspector then reviewed the procedures used in the calibration of these instruments to ensure that these environmental assumptions contained in the instrument loop uncertainty calculations were addressed in the procedure. The procedures reviewed were:

SP-161C	Remote Shutdown Instrument Calibration, Revision 13
PT-170	Nuclear Service Closed Cooling Surge Tank (SWT-1) Instrumentation Calibration, Revision 0

The inspector found that the calibration temperatures were not specified and that the procedures for calibration of instruments located in the Auxiliary Building did not assure that the Auxiliary Building temperatures were maintained within the temperature ranges assumed in the instrument loop uncertainty setpoint calculations. There were no procedural restrictions placed to prevent calibrating or operating the instruments at temperatures outside the temperatures assumed in the ESQPM or the instrument loop uncertainty setpoint calculations. Additionally, there were no procedures for ensuring the Auxiliary Building temperatures would be maintained within the ranges specified by the ESQPM or the instrument loop uncertainty setpoint calculations.

Therefore, the inspectors examined how ambient temperatures were controlled in the Control Building and the Auxiliary Building.

Paragraph 9.7.2.7 of the Final Safety Analysis Report (FSAR) provided the Operational Requirements for the Heating Ventilation and Air Condition (HVAC) systems. For the Auxiliary Building, paragraph 9.7.2.7.f stated, "Minimum temperature in these areas is 60° F." For the Control Complex, paragraph 9.7.2.7.h. stated, "... ambient is maintained at 75° F".

For the Control Complex, the Enhanced Design Basis Document (EDBD) specified 75° F for winter and 70° F for summer (general design conditions used in sizing of equipment) as operational parameters. For the Auxiliary Building, the EDBD specified 60° F minimum (for freeze protection and personnel comfort) and 122° F maximum (for environmental control for electrical equipment) as operational parameters.

For the Control Complex, the licensee provided the inspectors a graph of recorded temperatures for a year, which showed that the temperature in the Control Room had been maintained within a range of 70° F - 80° F. However, based on interviews with licensee personnel and review of procedures, there was no program for monitoring temperatures in the Auxiliary Building.

As noted in Section 8/7 of the EDBD, the purpose of the Auxiliary Building Heating Coils (AHHE-2A, AHHE-2B, and AHHE-12) was to maintain the Auxiliary and Fuel Handling Building at 60° F minimum. Review of

the maintenance history for the Auxiliary Building heaters and discussions with Engineering personnel revealed the following:

- The heaters were not included in the Preventive Maintenance (PM) Program. The instrument strings controlling the heaters are in the PM program and were being calibrated. The PMs for the instrument strings were implemented by Work Requests (WRs) NU 0266933, NU 0280142, and NU 0305381.
- In late 1995, as part of the boron reduction project, the Auxiliary Building heaters were inspected to determine their status and found to be not fully functional because of a number of blown fuses and other discrepancies. This was documented in Wrs NU 0329662 and NU 0332052. At that time, the heaters were repaired and made fully functional.
- In early January 1996, WR NU 0332052 was issued because heaters were not maintaining Auxiliary Building temperatures at 60° F. A blown control fuse was replaced and the heaters made operable. Temperatures were found to be 55° F on the second floor of the Auxiliary Building and 52° F on the spent fuel floor. The temperature transmitter setpoint for the heaters was 50° F, in accordance with drawings. Request for Engineering Assistance (REA) 960031 was issued to change the heater setpoint to 60° F, since a 50° F setting was not consistent with the EDBD requirement for maintaining the building at 60° F.

Based on the above review, the inspectors could not determine if the temperature in the Auxiliary Building in the past was always above the minimum indicated in the FSAR and the EDBD, since temperatures have not been periodically monitored. The heaters were not fully functional in late 1995. However, it could not be determined how long the heaters were not fully functional since the heaters were not included in the PM program and temperatures were not monitored. Also, the temperature transmitter that starts the heaters was set at 50° F. The input to the transmitter used the duct temperature just downstream of the air handling unit, which was essentially the temperature of the incoming outside air. Therefore, even if the heaters were fully functional, it was doubtful to the inspectors that using the duct temperature as the input to operate the heaters would result in the ambient temperature in the building being always maintained at 60° F minimum specified by the EDBD. Further, the 60° F minimum was not consistent with the ESQPM Zone 12 environmental assumptions of a 65° F minimum temperature.

c. Conclusions

The inspectors concluded that the licensee has made progress in resolving the ITS setpoint program deficiencies. Four recent calculations were well documented, with well founded assumptions, and followed the methodology specified in ISA 67.04, part II, as referenced by instrumentation and controls Design Criteria Instrument String Error/Setpoint Determination Methodology. These calculations were a

significant improvement over calculations reviewed in IR 95-06. However, there were several loop uncertainty calculations that were not complete and were scheduled to be completed by March 1, 1997. The final loop uncertainty determinations and instrument string error calculations need to be reviewed by the NRC after they are issued, to complete the followup inspection of EA 95-16.

The inspectors concluded that the Auxiliary Building temperature ranges which the ESQPM environmental assumptions used for the instrument loop uncertainty setpoint calculations were not maintained. Instrument setpoint calculations assumed certain temperatures in the Auxiliary Building for instrument calibration and operation. However, instrument calibration procedures did not address these temperatures; there were no procedural restrictions in place to prevent calibrating or operating the instruments at temperatures outside the temperatures assumed in the ESQPM or the instrument loop uncertainty setpoint calculations; and there were no procedures for ensuring the Auxiliary Building temperatures would be maintained within the ranges specified by the ESQPM or the instrument loop uncertainty setpoint calculations. This is a violation of design control requirements, VIO 50-302/97-01-07, Instrument Loop Uncertainty Setpoint Calculation Assumptions Not Translated Into Procedures.

The inspectors assessed the licensee's performance relative to lack of design control for Auxiliary Building temperatures assumed in instrument setpoint calculations, in the five areas of continuing NRC concern:

- Management Oversight - Inadequate
- Engineering Effectiveness - Inadequate
- Knowledge of the Design Basis - Inadequate
- Compliance with Regulations - Inadequate
- Operator Performance - N/A

E8.5 (Closed) IFI 96-201-13, Cable Ampacity Exceeded for DHP-1A [DCP-1A] Feeder Cable and Others

a. Inspection Scope (92903)

During NRC inspection 96-201, inspectors reviewed Calculation E91-0020, Rev 0, which sized safety-related AC power cables from the ampacity and short-circuit considerations, and noted that the calculation concluded that the cable for DCP-1A and several other cables required further evaluation. The licensee stated at that time that evaluation of the problem cables had been completed. However, the licensee could not find the evaluation for the inspector's review, and therefore, IFI 96-201-13 was established.

UFSAR Section 8.2.2.11.a states:

In general, motor and transformer feeder cables are rated at 125 percent of full load current. In some cases, the 125 percent of full load current rating is not met. However, as a minimum, the

cable will have a rating of 115 percent of full load current. This provides for motor and equipment operation at service factor ratings. The reference used for cable selection is the CR-3 Electrical Design Criteria - Cable Ampacity Sizing.

The scope of the inspection was to determine whether the above stated UFSAR requirement had been met; whether ampacity calculations were done in accordance with published standards; and whether NRC requirements in 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, were met.

b. Observations and Findings

The licensee had three calculations which dealt with sizing cables for ampacity. Calculation E91-0020 mentioned above covered the majority of safety-related AC power cables. A second calculation covered single phase vital AC cables. A third calculation covered safety-related DC cables.

The calculations were performed as part of the Electrical Calculation Enhancement Program, and, for the most part, "sized" cables which were already installed. The ampacity tables and derating factors upon which the calculations were based were taken from ICEA P-46-426, Power Cable Ampacities.

With regard to Calculation E91-0020, the inspector determined the following sequence of events through discussions with licensee engineers and document review. In 1992, the calculation was being developed, and engineers identified that several cables did not have the required ampacity when the generic derating factors were applied. This did not necessarily mean that the cables were overloaded, but it did mean that further analysis was necessary. Before the calculation was issued, Problem Report 92-0124 was initiated (in September 1992) to cover the potential problem cables. Forty-five cables were listed as potentially not meeting the requirements described in the scope section above [22 had ampacity less than full load amperes (FLA), and 23 had ampacity greater than FLA but less than 125 percent of FLA]. PR 92-0124 also mentioned that there was a generic problem with any cables covered with fire barrier material. The problem was that the fire barrier ampacity derating factors being used throughout the industry were significantly non-conservative. The fire barrier problem was described in NRC Information Notice 92-46.

The corrective action plan for PR 92-0124 addressed the 22 circuits having ampacity less than FLA. It did not have any corrective actions for the other 23 cables or the fire barrier problem. The fact that the corrective action plan did not include the fire barrier problem was of minor significance, because PR 92-0057 had already been generated for this problem in June 1992. PR 92-0124 was closed in June 1993. The calculation was issued during December 1993. The conclusions section of the calculation listed 18 cables that did not meet all of the design criteria and 3 cables that would meet the criteria if certain specified tray fill blocks were put in place within the computerized cable and

raceway program. There was no problem report generated for these cables; however, Electrical Calculation Enhancement Program Open Item No. 93-ECCEP-070 was established. This item was still open at the time of this inspection. Twelve of these cables were the same as noted in PR 92-0124, and 9 cables were different than previously noted. After NRC Inspection Report 50-302/96-201 identified a concern with how the problems were handled, the licensee initiated Precursor Card 96-3705.

The inspector reviewed the ampacity calculation sheets for 10 cables listed in PR 92-0124 as having ampacity less than full load amperes. The inspector observed that the calculation had been revised since initiation of the PR, and these cables met all the criteria. These cables were routed exclusively in conduit, and the originally applied conduit grouping derate factor was found overly conservative upon examination of the as-built configuration. The inspector confirmed, through review of records, that cable CHL-1 had been replaced with cable CHL-2 which increased the ampacity to meet the criteria. Therefore, cables listed in PR 92-0124 as being problem cables but not included in the list of problem cables in the calculation had been properly resolved.

From the set of 23 cables listed in the problem report that had ampacity between 100 and 125 percent of full load amperes, the inspector reviewed the ampacity calculation sheets for three selected at random. The inspector observed that these cables had been properly resolved.

Cable MTL-117, a 480-volt motor control center feeder cable, was listed in Calculation E91-0020 as a potential problem and was also addressed in Problem Report 92-124, which had been closed out. The calculation enhancement program open item indicated that this cable had been further analyzed and found to meet all the criteria. The inspector walked down this cable route in the plant, reviewed the ampacity calculation sheet (which had not been revised) and confirmed the load current. Based on the as-built configuration and application of the standard derate factors the inspector believed this cable had an ampacity problem. The licensee retrieved the informal work notes upon which the conclusion that cable MTL-117 was not a problem had been based. The licensee reviewed the work notes during the inspection, and reported to the inspector that the calculation methodology in the work notes was questionable.

In Calculation E91-0020, Cable AHC-656, a 480-volt supply to control room emergency ventilation return fan AHF-19B, was indicated to meet the criteria for ampacity but cautioned that certain tray sections must be limited to less than 43 power conductors. This issue was not addressed in a Problem Report. The licensee's method to limit tray fill for a particular tray section was to make the allowable fill equal the actual fill in the computer based cable and raceway program. This technique effectively placed a computer program block on adding any new cables to the tray in question. The inspector identified that the computer program block had not been implemented for the applicable cable tray sections (tray 107, sections 7 and 8).

Cable MTL-67, a 480-volt supply to motor control center MCC 3AB, had sufficient ampacity for the load, but Calculation E91-0020 indicated that the overcurrent protective device was set too high to protect the cable. This issue was not addressed in a Problem Report. The inspector examined the solid state trip device settings in the plant, and concluded that the set point (320 A) was too high to protect the cable (ampacity 237 A). The inspector also noted that a new breaker setting sheet had been issued in January 1995 which perpetuated the old incorrect setpoint.

c. Conclusions

Inspector Followup Item 96-201-13 raised concerns about the resolution for potential ampacity problems identified in 1992 and 1993. This inspector concluded that a violation of NRC requirements in the area of corrective action (10 CFR 50, Appendix B, Criterion XVI) had occurred. This conclusion was based primarily on the fact that Calculation E91-0020 had identified potential problems and indicated the need for corrective action in 1993, but the corrective action had not been implemented and/or the same problems still existed in 1997. Specifically, Cable MTL-117 had a questionable methodology applied within the problem report process, the tray fill block related to Cable AHC-656 had not been implemented, and the protective device setpoint for Cable MTL-67 had not been revised to protect the cable. These cables were randomly selected for review by the inspector, and problems were not necessarily limited to three cables. This is a violation of corrective action requirements IO 50-302/97-01-09, Inadequate Corrective Actions for Cable Ampacity.

The ampacity calculation performed under the Electrical Calculation Enhancement Program was performed according to widely accepted industry standards. A relatively small number of cables (order of magnitude one percent), were identified as potential problems. Therefore, the original design work for sizing cables performed in 1968 to 1977 time frame, when subjected to rigorous up-to-date analysis, was shown to be generally sound.

Inspector Followup Item 96-201-13, Cable Ampacity Exceeded for DHP-1A [DCP-1A] Feeder Cable and Others, was closed. The issues are encompassed by, and will be tracked under, the violation described above.

The fact that the Electrical Calculation Enhancement Program was completed represents management's willingness to expend resources to identify actively discrepancies between the design basis and the as-built plant. However, the circumstances described above indicate that once discrepancies were identified, sufficient care was not taken to ensure resolution. The licensee planned to resolve all ampacity concerns before restart of the unit, as evidenced by the fact that this was an item on the licensee's plant restart list.

With regard to the issue of cable ampacities, the inspector assessed the licensee's performance in the five NRC continuing areas of concern as follows:

- Management Oversight - Adequate
- Engineering Effectiveness - Inadequate
- Knowledge of the Design Basis - Adequate
- Compliance with Regulations - Inadequate
- Operator Performance - N/A

E8.6 (Open) URI 50-302/96-201-04, Nonsafety-Related Positioners on Safety-Related Valves

a. Inspection Scope (37550, 92903)

This URI involved a concern identified by the NRC during the Integrated Performance Assessment Process (IPAP) inspection, where safety-related air operated valves (DCV-17, DCV-18, DCV-177, and DCV-178) used to control cooling water flow to the decay heat removal heat exchangers were connected to nonsafety-related positioners. The inspector followed up on the licensee's corrective actions for this item.

b. Observations and Findings

Licensee corrective actions were documented in PR 96-0041 and PR 96-0220. The inspector reviewed the corrective actions that had been implemented or planned to address this item. The inspector reviewed these corrective actions for compliance with the FSAR, Technical Specifications, licensee Topical Design Basis Document, design control procedures, operating procedures, and 10 CFR 50 Appendix R.

The licensee had prepared MAR 94-09-02-01, DC Cooling Instrument Enhancement, to address this issue. The modification was evaluated by the licensee and determined to be a restart item. However, the inspector reviewed the licensee's scheduling of work during the current shutdown and noted that, based on recommendations by operations, MAR 94-09-02-01 was being scheduled for implementation during mode 1 operation after CR-3 restarted. The inspector noted that this implementation schedule was not consistent with the licensee's restart evaluation. Licensee personnel indicated that the MAR would be re-reviewed to determine the appropriate implementation schedule. During further review of this MAR, the inspector noted that the 10 CFR 50.59 screening determined that a 10 CFR 50.59 safety evaluation was not required. The inspector reviewed the 50.59 screening and determined that the screening was weak in that it lacked adequate detail to support the conclusion that a 10 CFR 50.59 safety evaluation was not required.

As discussed in the NRC IPAP inspection report 50-302/96-201 (Appendix C, paragraph 3.1.5), the NRC noted that implementation of MAR 94-09-02-01 would address the NRC's concern regarding the nonsafety-related positioners on Valves DCV-17, DCV-18, DCV-177, and DCV-178. However, the NRC had noted that a licensee interpretation during development of

the above MAR mistakenly concluded that the nonsafety-related positioners on the safety-related valves did not violate any design criteria and that failures of nonsafety-related equipment postulated to be less than $10E-6$ need not be considered. The inspector discussed with licensee personnel the IPAP team's observation regarding interpretation of the design criteria. Licensee personnel indicated that the design criteria in question was the Crystal River Unit 3 Topical Design Basis Document (TDBD) for the Single Failure Criteria, Revision 1, dated April 25, 1994. The inspector reviewed the TDBD and noted that the IPAP team questioned the applicability of the $10E-6$ criteria included in the TDBD for single failure of nonsafety-related components. This item remains open, and the NRC will continue to review this item to determine the licensee's schedule for implementation of MAR 94-09-02-01 and further review of the licensee's design criteria for single failure of nonsafety-related components to verify that it is consistent with NRC requirements.

During further review of MAR 94-09-02-01, the inspector noted that the MAR identified certain operating procedures that needed to be revised as a result this MAR. In addition to the operating procedures identified in the MAR, the inspector also reviewed licensee abnormal procedures (AP) to determine if any were impacted by the MAR. One of the abnormal procedures reviewed by the inspector was AP-990, Shutdown From Outside Control Room, Revision 8. The inspector noted that this AP provided procedural steps for taking the plant to hot standby and then directed operations personnel to maintain the plant in hot standby until a specific cooldown plan was formulated. The AP did not contain steps for taking the plant from hot standby to cold shutdown, and the AP did not provide a reference or transition to any other procedure that would be used by the operators to take the plant to cold shutdown. The inspector discussed this issue with licensee personnel who stated that credit was being taken for Operating Procedure OP-209, Plant Cooldown, Revision 87, which was the procedure that provided guidance to the operators for taking the plant from hot standby to cold shutdown. The inspector reviewed OP-209 and noted that Enclosure 1 to the procedure provided information concerning cooldown following a fire in the main control room or cable spreading room. This enclosure provided general guidance for certain fire scenarios and stated that this information was intended to assist plant personnel in designing a specific cooldown procedure following main control room evacuation. The inspector determined that the procedures (AP-990 and OP-209 being used either separately or in conjunction with each other) did not provide adequate instructions for taking the plant from hot standby to cold shutdown from outside the main control room. The inspector reviewed FSAR Section 7.4.6, Auxiliary Control Stations (Remote Shutdown System) and FSAR Section 9.8, Plant Fire Protection Program. FSAR Section 7.4.6.5 states in part that the design basis for the remote shutdown system is 10 CFR 50, Appendix R, Section L. FSAR Section 9.8.6 states that plant procedures developed in accordance with 10 CFR 50, Appendix R, Sections III.G and III.L establish means to bring the plant from operating to cold shutdown. The inspector further concluded, that licensee Procedures AP-990 and OP-209 did not meet the requirements of 10 CFR 50, Appendix R. The guidance in

Procedure OP-209, which directs operations personnel to develop a specific cooldown procedure to take the plant to cold shutdown based on an assessment of the fire scenario and equipment availability, does not meet the criteria in Section III.L of 10 CFR 50, Appendix R. Section III.L states that procedures shall be in effect to implement the capability of being able to take the plant to cold shutdown within 72 hours following main control room evacuation due to a fire. Licensee personnel stated that AP-990 and OP-209 meet the intent of Section III.L. The inspector informed the licensee that, this issue was unresolved pending further NRC review of applicable SERs which discuss the licensee's Appendix R program. This issue will be identified as URI 50-302/97-01-08, Adequacy of Procedures to Take the Plant from Hot Standby to Cold Shutdown from Outside the Control Room.

c. Conclusions

The inspector concluded that the schedule for implementation of MAR 94-09-02-01 to address the issue of nonsafety-related positioners on safety-related valves was inconsistent with the licensee's restart panel recommendation. The inspector concluded that licensee Procedures AP-990 and OP-209, used either separately or in conjunction with each other, did not provide adequate instructions for taking the plant to cold shutdown within 72 hours following main control room evacuation due to a fire. These procedures did not meet the requirements of Section III.L of 10 CFR 50, Appendix R. A URI was identified pending further NRC review of applicable SERs which discuss the licensee's Appendix R program.

The inspector assessed the licensee's performance, with respect to this issue, in the five areas of continuing NRC concern:

- Management Oversight - Adequate
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Inadequate
- Operator Performance - N/A

E8.7 (Closed) Inspector Followup Item (IFI) 50-302/95-15-01, Design Requirements for Nitrogen Overpressure

a. Inspection Scope (92903)

This IFI dealt with a unique feature of the Crystal River nuclear service water system, a surge tank that was pressurized with nitrogen and not located at the highest point in the system. The function of the tank appeared to be for ensuring the system pressure remained at 60 psi. Following Inspection 50-302/95-15 the licensee reviewed the system design basis and determined that the setpoints associated with the surge tank should be verified. This IFI was reinspected in inspection report 50-302/96-21; however, the IFI was left open pending the review of the calculations and validation that the alarms were changed.

b. Observations and Findings

The inspector reviewed the applicable calculations:

- M95-0035. SW System Inventory Transient Analysis, Revision 1.
- M93-0018. Nuclear Service Closed Cycle Surge tank (SWT-1) Volume, Revision 1.
- M92-0019. SW Surge Tank Tie-in Pressure Drop Analysis, Revision 3.
- I91-0004. Nuclear Service Closed Cycle Surge Tank Instrumentation Accuracies, Revision 3.

Calculation M95-0035 demonstrated that the as-found setpoints for SW-134-PSI and SW-137-LS were not appropriate. The setpoints for these instruments were changed in I91-0004. These setpoint changes were included in Surveillance Test PT-170, Nuclear Service Closed Cycle Surge Tank (SWT-1) Instrument Calibration.

There was one area of confusion regarding the units of the exact location of the SW Surge Tank High Level alarm. The calibration Procedure PT-170 described the set point as 109'6". The annunciator alarm Procedure ESAB-A-01-08 described the location as 10'0". The calculation I91-004 described the location as 109'6" plant elevation, 11'6" tank elevation, or 10' transmitter elevation. Calculation M95-0035 Assumption 5.6, tank drawing on page 22 of 23, tank drawing on page 10 of 10, describes the Hi-alarm setpoint as 111'-0". The November 22, 1995, letter IOC NED95-0691 described the setpoint changing from 110'6" to 109'6". Finally, the vendor Drawing 5-315-D1, listed the normal water level at 109'6" (Normal operating level = Tank bottom elevation + tank height - distance from top of tank to normal water level) = (109'6" = 98' + 16' - 4'6"). This level was at the high alarm setpoint. The inspector was informed that although this drawing was available through document control, it was an original tank drawing and was not used for any specific purpose.

c. Conclusions

The inspector found that there were four separate level measurement systems used to refer to this setpoint. These were:

- (1) Distance from an arbitrary plant datum point
- (2) Distance from the floor of the room in which the tank is located
- (3) Distance from the inside edge of the bottom of the tank
- (4) Distance from an arbitrary zero in the tank

The inspector concluded that, while the four different elevation systems used to refer to the same point, other than presenting the possibility for future errors, there were no consequences for this particular calculation or its resulting setpoint. The inspector concluded that the licensee had completed the loop uncertainty calculation and

appropriately calibrated the affected instrumentation, and that these actions adequately addressed the portions of IFI 95-15-01, Design Requirements for Nitrogen Overpressure, that were not reviewed or closed in IR 50-302/96-21.

The inspector assessed the licensee's performance, with respect to this issue, in the five areas of continuing NRC concern:

Management Oversight - Management oversight was judged to be good, in that, there was management involvement throughout the project, and when small procedural concerns were identified they were dealt with in an expeditious manner.

Engineering Effectiveness - The engineering was judged as good. The conclusions were acceptable and the new setpoints were technically sound and were appropriately translated into procedures.

Knowledge of Design Bases - The licensee's design basis knowledge was judged as adequate. The reason that this IFI was opened was because there was not a complete understanding of the systems design basis. At the conclusion of this calculation the licensee had reconstructed the design basis for the SW surge tank. One aspect of calculation, I91-0004, Nuclear Service Closed Cycle Surge Tank Instrumentation Accuracies, Revision 3 that was not appropriately addressed, was the translation of the associated nuclear service closed cycle surge tank Auxiliary Building instrumentation accuracies into appropriate calibration procedures. This is addressed in paragraph E8.4.

Compliance With Regulations - The utility demonstrated the appropriate amount of regulatory sensitivity for this issue. There was reasonably timely work, the calculations were accurate, and the results were available for review. The inspector judged this area as good.

Operator Performance - There was limited operations involvement in this project. However, as noted above there were inconsistencies in units between the annunciator response procedure and the calibration procedure. There were apparently discrepancies between the actual level and the level reported in an original vendor drawing. However, in spite of this potential confusion, the appropriate levels appear to be on the installed equipment and in the alarm response procedure, the area of operations was judged as adequate.

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Adequate
- Compliance with Regulations - Good
- Operator Performance - Adequate

E8.8 (Open) VIO 50-302/96-09-07, Inadequate Corrective Action for Implementation of EFIC Task Force Recommendations

a. Inspection Scope (37550, 92903)

This violation involved failure of the licensee to take adequate and timely corrective actions to implement recommendations from the Emergency Feedwater Initiation and Control (EFIC) task force. The inspector followed up on the licensee's corrective actions for this violation.

b. Observations and Findings

The inspector reviewed the corrective actions specified in the licensee's response to this violation. The inspector reviewed these corrective actions for compliance with the FSAR, TS, and applicable licensee procedures. The inspector noted that some of the corrective actions specified in the response had been implemented. Corrective actions implemented included all Requests for Engineering Assistance (REA), which requested a plant modification, being reviewed and approved by the Plant Modification Review Group (PMRG); a list of high priority modifications was being maintained by the PMRG; high priority EFIC/EFW issues were being addressed during the present shutdown; and additional resources (permanent and contract personnel) were added to the engineering organization to ensure that high priority tasks were being worked. The inspector noted that the modifications to address the high priority EFIC/EFW issues had not been implemented.

During review of the corrective actions, the inspector noted that many of the EFIC Task Force recommendations were not included on the licensee's restart list. The inspector questioned licensee personnel as to whether the EFIC Task Force recommendations had been or would be evaluated against their restart criteria. This question was further amplified when the inspector noted that precursor card (PC) No. 97-0595 was initiated on January 28, 1997, which questioned whether one of the EFIC Task Force recommendations should be evaluated as a restart restraint during the current shutdown rather than the scheduled implementation during Refuel 11. Licensee personnel indicated that PC 97-0595 would be evaluated against their restart criteria by the restart panel. This item remains open pending further review of the licensee's evaluation of PC 97-0595 and other EFIC Task Force recommendations by the restart panel.

c. Conclusion

The inspector concluded that the licensee had implemented a number of corrective actions to address this violation. However, not all EFIC Task Force recommendations had been reviewed by the licensee using their restart criteria.

The inspector assessed the licensee's performance, with respect to this issue, in the five areas of continuing NRC concern:

- Management Oversight - Adequate
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Good
- Operator Performance - N/A

E8.9 (Open) VIO 50-302/95-21-03, Failure to Isolate the Class IE from the Non Class IE Electrical Circuitry for the Reactor Building Purge and Mini-Purge Valves

a. Inspection Scope (37550, 92903)

This violation involved failure of the licensee to isolate Class IE from Non Class IE electrical circuitry for the reactor building purge and mini-purge valves. The inspector followed up on the licensee's corrective actions for this violation.

b. Observations and Findings

The inspector reviewed the corrective actions specified in the licensee's response to this violation. The corrective actions were reviewed for compliance with the FSAR, TS, and applicable licensee procedures. The inspector noted that some of the corrective action specified in the response had been completed. Other corrective actions involved implementation of modifications to address the issue. Some of the modifications had been implemented. During review of the corrective actions, the inspector noted that the licensee's evaluation of alternatives to the present non-isolated design of the control circuits for reactor building purge valves AHV-1A and AHV-1D had not been completed by the scheduled date of December 20, 1996. The new schedule date for completion of the evaluation was changed to May 1998. The inspector discussed this change with licensee personnel who indicated that the schedule change was due to an increase of other higher priority issues such as EFIC/EFW and EDG loading. The inspector also questioned whether this issue had been evaluated as a potential restart issue and licensee personnel indicated that the issue had not been evaluated by their restart panel. This item remains open.

c. Conclusion

The inspector concluded that the licensee has completed some of the specified corrective actions to address this issue. However, due to workload and higher priority issues related to the EFIC/EFW and EDG loading, the scheduled completion date for other corrective actions was not met and the completion date was extended.

The inspector assessed the licensee's performance, with respect to this issue, in the five areas of continuing NRC concern:

- Management Oversight - Adequate
- Engineering Effectiveness - Adequate
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Good
- Operator Performance - N/A

E8.10 (Open) NRC Generic Letter 96-06, Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

a. Inspection Scope (92903)

GL 96-06, issued September 30, 1996, requested certain actions from all operating nuclear power reactors relative to the following safety-significant issues:

- During a loss of coolant accident (LOCA) or a main steamline break (MSLB), cooling water systems serving the containment air coolers may be exposed to waterhammer for which they were not designed.
- During LOCA and MSLB scenarios, cooling water systems serving the containment air coolers may experience two-phase flow conditions that were not considered in heat removal assumptions resulting in system design and operability questions.
- Thermally induced overpressurization of isolated water-filled piping sections in containment could jeopardize the ability of accident-mitigating systems to perform their safety functions and could lead to breach of containment integrity via bypass leakage.

In this inspection, the inspectors examined the licensee's actions to date for evaluation and corrective actions relative to thermally induced overpressurization of isolated piping sections.

b. Observations and Findings

GL 96-06 requested that licensees determine if piping systems that penetrate the containment were susceptible to thermal expansion so that overpressurization of piping could occur. If systems were found to be susceptible, licensees were expected to assess the operability of affected systems and take corrective action as appropriate. Licensees were requested to submit a written summary report within 120 days of the date of the GL letter stating the actions taken in response to the requested actions, including conclusions reached relative to susceptibility for overpressurization of piping that penetrates the containment, the basis for continued operability of affected systems, and corrective actions that were implemented or planned.

The licensee's 120 day response was submitted on January 27, 1997. The response detailed the review performed to determine containment

penetration piping susceptible to overpressurization. For the containment penetration process piping susceptible to overpressurization, the licensee has designed and is installing rupture discs and expansion chambers to allow for expansion of the process fluid. For all susceptible penetrations, except SW system penetrations 314 and 318, rupture discs will be enclosed in expansion chambers located outside the containment. For SW penetrations 314 and 318, rupture discs will be installed inside the containment without expansion chambers. The rupture discs will be connected to the process piping with 3/8" diameter tubing. In addition to installation of expansion chambers for containment penetration piping, the licensee was still evaluating the need for additional relief valves in other piping.

Although, based on the size of piping (tubing) between process piping and the expansion chambers, the expansion chamber would be exempt from ASME Section XI requirements, the licensee applied ASME Section XI requirements to the design, fabrication and installation of the expansion chambers. This resulted in the use of USAS B31.1, 1967 Edition and B31.7, 1969 Edition, as the applicable Codes.

The inspectors observed the following relative to design, procurement and installation of the expansion chambers:

- Engineering - The inspectors reviewed the approved MAR 96-10-04-01, including the 10 CFR 50.59 Evaluation and the Installation Instructions.

During review of the MAR package, the inspector noted that the Inservice Inspection (ISI) Requirements check sheet had not been properly completed. The ISI check sheet is used during the MAR development and review process to have ISM personnel review the MAR package to ensure that ISM requirements are adequately addressed. For MAR 96-10-04-01, the check sheet had been signed by the Nuclear ISM Specialist indicating his review, but he failed to check-mark the ISI Requirements as "Acceptable" or "Unacceptable". For this case, the failure to complete the ISI Requirements form properly was not that significant since no ISI was required and there was a later required review for ISI requirements at the time of issue of the installation work packages. However, issue of the MAR package without the ISI check sheet being properly completed indicates a weakness in the MAR review and approval process. The licensee issued a Precursor Card to document and take appropriate corrective actions for this weakness. Also, prior to this inspection, the licensee had identified the need to strengthen their procedures in the area of ISI review of MAR packages. Procedure revisions were in process.

For containment penetrations 314 and 318, which will have rupture discs installed inside the containment without expansion chambers, the inspectors questioned the licensee relative to the need to provide an exclusion zone around the rupture discs to ensure that future modifications do not install equipment where it might be

damaged in the event of a rupture disc rupture. Engineering personnel stated that the need for an exclusion area would be evaluated and added if considered necessary.

- Procurement - Sample records from Purchase Order F810203D procurement package were reviewed. Records reviewed included: FPC Receiving Inspection Report and Inspection Plan; Welding Services, Inc. (WSI) Certificate of Conformance; Fabrication Traveler 36077001 for chambers MURS-1 and MURS-2; Weld Data Sheets for Welds SW-1, 2, 3, 4, 5, and 6; radiographic film reader sheets for chambers CARS-1, MURS-1, CFRS-1, SFRS-1 and DHRS-1; certification for NDE materials; and FPC letters of approval for Welding Specifications, NDE Procedures, and welder qualifications.
- Installation Activities -

The inspectors observed portions of the welding and liquid penetrant (PT) examination for weld CA-85-86 on WR NU 0339386, welds CA-85-85 and CA-85-127 on WR NU 0339390, and weld CA-85-149 on WR NU 0339392. In addition, for the welds observed, welder qualification records, weld material test reports, NDE examiner certification records, and penetrant material test reports were reviewed.

c. Conclusions

The inspector concluded that the licensee was performing detailed evaluations and developing solutions for the issues identified in GL 96-06. Overall, the MAR package, including the 10 CFR 50.59 evaluation, for design, procurement, and installation of the containment penetration process piping expansion chambers was detailed and well documented, demonstrating good Engineering performance. Procurement activities were detailed and well documented. Welding and inspection work activities associated with installation of the expansion chambers were good with detailed, neat, and well-maintained documentation.

One weakness was identified relative to completion of the ISI Requirements check-sheet.

The inspector assessed the licensee's performance, with respect to this issue, in the five NRC continuing areas of concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - N/A

IV. Plant Support

F3 Fire Protection Procedures and Documentation

F3.1 Fire Protection System Recirculation Limits

a. Inspection Scope (71707)

The inspectors reviewed the licensee's response to improper control of fire pump recirculation flow that resulted in a condition where all three fire pumps were rendered inoperable.

b. Observations and Findings

On January 17, 1997, the licensee placed motor-driven fire service pump (FSP) 1 in service per Operating Procedure (OP) 880, Fire Service System, Revision 9, to recirculate both fire service tanks. This implemented Operation Instruction (OI) 13, Adverse Weather Conditions, Revision 1, for potentially freezing temperatures. The two other fire pumps, diesel-driven FSP-2A and FSP-2B, were both rendered inoperable on January 17 because both fire pump building fans had to be disabled and placed in pull-to-lock as required by OI-13. This removed the combustion air supply for the diesel FSPs so they had to be declared inoperable. On January 18 a concern was raised about the continued lifting of the FSP-1 discharge relief valve due to the low recirculation flow of 600 gpm and corresponding high discharge pressure. This was a concern because the relief valve water was directed to the turbine building sump and required processing prior to being released offsite. The recirculation flow was raised to 2000 gpm after consulting with a fire protection engineer to lower the pressure and reseal the valve. Approximately five hours later, oncoming shift operators questioned the impact of the higher recirculation flow rates on operability of FSP-1. Although OP-880 only contained a note to ensure recirculation flow does not exceed 2000 gpm, further consultations with fire protection engineers revealed that any flow above 600 gpm rendered the pump inoperable due to the lower discharge pressure and flow diverted from the header for recirculation. Consequently, all 3 FSPs were inoperable for over five hours.

Shift supervision immediately recognized the seriousness of this situation and restored the two diesel FSPs to operable, initiated an OI-12 investigation, and developed a Short Term Instruction to provide interim recirculation flow rate guidance. PC 97-357 was initiated to perform a root cause investigation, and the Director of Nuclear Plant Operations prioritized this issue by placing it on his "short fuse" list. The root cause evaluation and corrective actions were developed by January 31. Although subsequent revisions delayed issuance of it until February 5 and the licensee's Corrective Action Review Board (CARB) did not review the event until February 18, the inspector noted the licensee's root cause determination and corrective action plans were adequate. The licensee determined that the 600 gpm recirculation limit was not contained in procedures and was not reflected in the Fire

Protection Plan. Their investigation revealed several other communication and procedural problems which they adequately addressed. Consequently, this licensee identified violation meets the requirements outlined in Section VII of the Enforcement Policy and will not be cited. This issue is identified as Non-Cited Violation NCV 50-302/97-01-03, Inadequate Fire System Recirculation Procedure.

c. Conclusion

The inspectors concluded that the subsequent operations shift exhibited a questioning attitude that resulted in the discovery of this condition. Corrective action was implemented in a timely manner although the delay for the CARB to review the corrective action plan left room for improvement. The inspectors had concerns about the lack of guidance in the procedures for the operators to make operability determinations but were satisfied that the licensee's corrective actions would address them.

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Comments (71750)

The inspectors conducted routine tours of the licensee's radiologically controlled areas (RCA) and verified radiological controls such as control of locked areas, surveys and postings, and access controls. The inspectors routinely observed status of the radiation monitoring and meteorological systems. Chemistry results were typically reviewed daily during normal work days. Generally, good performance was noted in these areas. High radiation areas were clearly marked and locked.

The inspectors observed daily priority is placed on tracking of radiological exposure against outage goals. Although the goal and exposure amount occasionally did not agree, the licensee was actively refining their predictions and results were improving. The inspectors also observed that the licensee accomplished a notable achievement, in that the reactor building was decontaminated sufficiently to relax some protective clothing requirements for tours and walkthroughs. The inspectors did not identify any deficiencies in the areas of radiological controls or chemistry.

S1 Conduct of Security and Safeguards Activities

S1.1 Protected Area Security Breach

a. Inspection Scope (71750)

On January 30, 1997, at 6:45 p.m. the licensee discovered a penetration path into the protected area via a breach in a condenser waterbox. The inspector reviewed the licensee's investigation documentation in PC 97-0053 and Security Information Report 10815 and interviewed licensee personnel.

b. Observations and Findings

The breach was discovered by an alert security officer who questioned maintenance work that had removed components he did not recognize. The breach was immediately posted as a compensatory measure and security force members initiated efforts to determine the scope of the problem. They determined that the breach had existed for approximately 16 hours and was in excess of the allowable security plan breach size, so it did constitute a protected area breach. The inspector noted that the maintenance work was stopped and the security guards performed an inspection of the vital and protected areas to ensure they were not compromised. The licensee reported the event as discussed in paragraph 01.2 and was developing a written Licensee Event Report. The inspector determined that security personnel had been properly notified of the maintenance work, and it had been evaluated for the potential to cause a breach. However, following the removal of the components the security officer expressed a concern that a penetration path was opened that was not recognized by the licensee. Consequently, appropriate compensatory measures were not implemented. The licensee had a similar penetration pathway via a waterbox breach on November 1, 1996, which was identified by the NRC as Escalated Enforcement Item 50-302/96-18-04. The corrective actions for that item and the January 30 occurrence were discussed at an Enforcement Conference held at the NRC Region II Office on February 14, 1997. The resulting enforcement action EA 97-012 was issued on February 28, 1997. The above violation is an additional example of violation No. A(4)(01043) which was issued in EA 97-012. The inspectors determined that those corrective actions, which were not yet fully implemented, would be adequate to address the problems. The inspector also observed that licensee management assembled an effective investigation team the next day to assess the potential for any other penetration pathways although their expectation was that this effort would be initiated by shift management at the time of occurrence.

c. Conclusions

The inspectors identified the January 30 waterbox breach as a second example of violation No. A(4)(01043) which was issued in EA 97-012. The inspector concluded the licensee security staff displayed a questioning attitude to discover the breach, but the licensee's initial investigation was not prioritized properly as discussed above and in paragraph 01.2. The inspectors concluded the licensee's planned corrective actions were appropriate to prevent recurrence.

S1.2 Security Event Log Audit (71750)

The inspector audited the Security Event Log (SEL), required by Appendix G of 10 CFR 73, for the first, second, and fourth quarters of calendar year 1996. The inspector verified selected problems were adequately logged and that log items were routinely reviewed by security management. The inspector reviewed the Security Information Reports (SIR) associated with several of the logged problems in detail and did not identify any problems. These events included problems such as vital

area doors left unsecured, security badges inadvertently removed from the site, and human error events. The inspector also observed that a PC document was generated on initiation of each SIR to include the problem in the plant wide corrective action program. The inspector concluded this was a good practice for both management visibility and trending purposes. The inspector did not identify any problems with the number of events and observed that the trends in some areas such as unsecured vital doors were notably improved. The inspector concluded the licensee was appropriately maintaining the Security Event Log.

V. Management Meetings

X1 Exit Meeting Summary

The inspection scope and findings were summarized on January 31, February 14 and February 27, 1997. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

X2 Pre-Decisional Enforcement Conference Summary

X2.1 An Enforcement Conference was held on January 24, 1997, in Region II to discuss apparent violations associated with the Emergency Diesel Generators, the Emergency Feedwater System and containment penetrations. Results of this meeting were issued as an escalated enforcement action on March 12, 1997.

X2.2 An Enforcement Conference was held on February 14, 1997, in Region II to discuss apparent violations associated with Security. These apparent violations are discussed in Inspection Report 50-302/96-18, and results of this meeting were issued as an escalated enforcement action on February 28, 1997.

X3 Management Meeting Summary

X3.1 A public meeting was held on site at Crystal River February 12, 1997. The purpose of the meeting was to discuss items related to restart. A separate meeting summary was issued on February 19, 1997.

PARTIAL LIST OF PERSONS CONTACTED

Licensees

K. Baker, Manager, Nuclear Configuration Management
 D. Bates, Manager, Quality Systems
 J. Baumstark, Director, Quality Programs
 P. Beard, Senior Vice President, Nuclear Operations
 G. Becker, Manager, Nuclear Operations
 J. Campbell, Assistant Plant Director, Maintenance
 W. Conklin, Jr., Director, Nuclear Operations Materials and Controls
 J. Cowan, Vice President, Nuclear Production
 D. Daniels, Manager, Nuclear Safety Assessment Team
 R. Davis, Assistant Plant Director, Operations

D. DeMontfort, Manager, Nuclear Operations
 M. Donovan, Supervisor, Rapid Engineering Response Team
 B. Gutherman, Manager, Nuclear Licensing
 G. Halnon, Assistant Director, Nuclear Operations Site Support
 B. Hickie, Director, Nuclear Plant Operations
 J. Holden, Director, Nuclear Engineering and Projects
 R. Knoll, Supervisor, Nuclear Engineering
 H. Koon, Manager, Nuclear Production and Nuclear Outage
 D. Kunsemiller, Director, Nuclear Operations Site Support
 J. Maseda, Manager, Engineering Programs
 R. McLaughlin, Nuclear Regulatory Specialist
 D. Poole, NGRC Member
 D. Roderick, Manager, Outage and Work Controls
 W. Rossfeld, Manager, Site Nuclear Services
 J. Stephenson, Manager, Radiological Emergency Planning
 F. Sullivan, Manager, Nuclear Engineering Design
 J. Terry, Manager, Nuclear Plant Technical Support
 J. Tunstill, Senior Nuclear Licensing Engineer
 D. Watson, Manager, Nuclear Security
 R. Widell, Director, Nuclear Operations Training
 D. Wilder, Manager, Radiation Protection and Chemistry
 R. Yost, Manager, Nuclear Quality Assessment

NRC

B. Crowley, Reactor Inspector, Region II (January 27 through 31, 1997, February 10 through 14, 1997)
 P. Fillion, Reactor Inspector, Region II (January 27 through 31, 1997, February 10 through 14, 1997)
 F. Hebdon, Director, Directorate II-3, NRR (February 12, 1997)
 J. Jaudon, Director, Division of Reactor Safety, Region II (February 11 through 12, 1997)
 K. Landis, Branch Chief, Region II (January 27 through 29, 1997)
 L. Mellen, Project Engineer, Region II (January 27 through 31, 1997, February 10 through 14, 1997)
 L. Raghavan, Project Manager, NRR (February 10 through 13, 1997)
 R. Schin, Reactor Inspector, Region II (January 27 through 31, 1997, February 10 through 14, 1997)
 M. Thomas, Reactor Inspector, Region II (January 27 through 31, 1997, February 10 through 14, 1997)

INSPECTION PROCEDURES USED

IP 37550: Engineering
 IP 37551: Onsite Engineering

 IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving and Preventing Problems
 IP 61726: Surveillance Observations
 IP 62703: Maintenance Observations
 IP 62707: Conduct of Maintenance
 IP 71707: Plant Operations
 IP 71750: Plant Support Activities

IP 92900: Onsite LER Review
 IP 92901: Followup - Operations
 IP 92902: Followup - Maintenance
 IP 92903: Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

<u>Type</u>	<u>Item Number</u>	<u>Status</u>	<u>Description and Reference</u>
VIO	50-302/97-01-01	Open	Inadequate Clearance Tagging Requirements. (paragraph 01.3)
VIO	50-302/97-01-02	Open	Failure to Follow Procedures, Resulting in an Inadvertent Emergency Diesel Generator Start. (paragraph 01.6)
VIO	50-302/97-01-04	Open	Failure to Perform Technical Specification Surveillance for Spent Fuel Pool Level. (paragraph M1.1)
URI	50-302/97-01-06	Open	HPI System Design, Licensing Basis, and TS Concerns. (paragraph E1.3)
VIO	50-302/97-01-07	Open	Instrument Loop Uncertainty Setpoint Calculation Assumptions Not Translated Into Procedures. (paragraph E8.4)
URI	50-302/97-01-08	Open	Adequacy of Procedures to Take the Plant from Hot Standby to Cold Shutdown from Outside the Control Room. (paragraph E8.6)
VIO	50-302/97-01-09	Open	Inadequate Corrective Actions for Cable Ampacity. (paragraph E8.5)

Closed

<u>Type</u>	<u>Item Number</u>	<u>Status</u>	<u>Description and Reference</u>
NCV	50-302/97-01-03	Closed	Inadequate Fire System Recirculation Procedure. (paragraph F3.1)
NCV	50-302/97-01-05	Closed	Inadequate Surveillance Procedure to Test Operability of Toxic Gas Chlorine Detectors. (paragraph M1.5)
VIO	50-302/96-05-01	Closed	Failure to Follow Procedures to Initiate Corrective Action for Bent Main Steam Line Hangers. (paragraph 08.1)
VIO	50-302/96-05-05	Closed	Failure to Follow Procedures for Updating

DBDs. (paragraph E8.1)

VIO	50-302/96-05-07	Closed	Inadequate Receiving Inspections for Battery Chargers. (paragraph E8.2)
VIO	50-302/96-05-08	Closed	Failure to Follow Purchasing Procedures for Inverters. (paragraph E8.3)
LER	50-302/96-12-02	Closed	Operation Outside Design Basis Caused by Battery Chargers Having Inadequate Test Results Accepted in Error. (paragraph E8.2)
IFI	50-302/95-15-01	Closed	Design Requirements for Nitrogen Overpressure. (paragraph E8.7)
IFI	50-302/96-201-13	Closed	Cable Ampacity Exceeded for DHP-1A [DCP-1A] Feeder Cable and Others. (paragraph E8.5)
URI	50-302/96-05-02	Closed	Design Concerns with the Main Steam Line Hangers Used in Seismic and Other Dynamic Load Applications. (paragraph E8.1)
NCV	50-302/97-01-10	Closed	Inadequate Design Control, Non-Safety Related Components in Safety Related Applications - Two Examples: Thyrite Surge Protection Device, Operator and Controller for MUV-103. (paragraph E1.2)

Discussed

<u>Type</u>	<u>Item Number</u>	<u>Status</u>	<u>Description and Reference</u>
URI	50-302/96-17-03	Open	Failure to conduct required technical specification surveillance testing on safety related circuitry. (paragraph M8.1)
URI	50-302/96-201-04	Open	Non Safety-Related Positioners on Safety-Related Valves. (paragraph E8.6)
VIO	50-302/96-09-07	Open	Inadequate Corrective Actions for Implementation of EFIC Task Force Recommendations (paragraph E8.8)
VIO	50-302/95-21-03	Open	Failure to Isolate the Class IE from the Non Class IE Electrical Circuitry for the Reactor Building Purge and Mini-Purge Valves. (paragraph E8.9)
EA	50-302/96-016	Open	Use of Nonconservative Trip Setpoints for Safety-Related Equipment. (paragraph E8.4)

EA 50-302/97-012 Open Failure to Maintain Protected Area
Barriers. Second Example of EA 97-017.
Violation A(4)(01043). (paragraph S1.1)

LIST OF ACRONYMS USED

AI - Administrative Instruction
AP - Abnormal Procedures
AR - Air Removal
BAST - Boric Acid Storage Tank
CARB - Corrective Action Review Board
CCHE - Control Complex Habitability Envelope
CFR - Code of Federal Regulations
CFT - Core Flood Tank
CREVS - Control Room Emergency Ventilation System
CR3 - Crystal River Unit 3
CT - Current Transformers
DBD - Design Basis Document
DBI - Design Basis Issue
DH - Decay Heat
DHP - Decay Heat Pump
DHV - Decay Heat Valve
DNPO - Director, Nuclear Plant Operations
EA - Enforcement Action
ECCS - Emergency Core Cooling System
EDBD - Enhanced Design Basis Document
EDG - Emergency Diesel Generator
EEI - Escalation Enforcement Item
EFIC - Emergency Feedwater Initiation and Control
EFW - Emergency Feedwater
ES - Engineered Safeguards
ESQPM - Environmental and Seismic Qualification Program Manual
FLA - Full Load Amperes
FLUR - First Level Undervoltage Relays
FME - Foreign Material Exclusion
FPC - Florida Power Corporation
FSAR - Final Safety Analysis Report
FSP - Fire Service Pump
FTI - Framatome Technologies, Inc.
GL - Generic Letter
HPI - High Pressure Injection
HVAC - Heating Ventilation and Air Condition
I&C - Instrumentation and Control
IFI - Inspection Followup Item
IPAP - Integrated Performance Assessment Process
ISA - Instrument Society of America
ISI - Inservice Inspection
Kw - Kilowatts
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOOP - Loss of Offsite Power
LPI - Low Pressure Injection

MAR	- Modification Approval Record
MCAP	- Management Corrective Action Plan
MSLB	- Main Steamline Break
MUV	- Make-up Valve
NCV	- Non-cited Violation
NEP	- Nuclear Engineering Procedure
NGRC	- Nuclear General Review Committee
NOTES	- Nuclear Operations Tracking and Expediting System
NOV	- Notice of Violation
NPSH	- Net Positive Suction Head
NP&SM	- Nuclear Procurement and Storage Manual
NQA	- Nuclear Quality Assessments
NRC	- Nuclear Regulatory Commission
NRR	- Office of Nuclear Reactor Regulation
OCR	- Operability Concerns Resolution
OI	- Operating Instruction
OJT	- On The Job Training
OP	- Operating Procedure
PC	- Precursor Card
PM	- Preventive Maintenance
PMRG	- Plant Modification Review Group
PMT	- Post Maintenance Test
PORV	- Power Operated Relief Valve
PR	- Problem Report
PRC	- Plant Review Committee
PT	- Liquid Penetrant Test
RCA	- Radiologically Controlled Area
RCBT	- Reactor Coolant Bleed Tanks
RCP	- Reactor Coolant Pump
RCS	- Reactor Coolant System
REA	- Request for Engineering Assistance
RG	- Regulatory Guide
RP&C	- Radiological Protection and Chemistry
SBLOCA	- Small Break Loss of Coolant Accident
SEL	- Security Event Log
SIR	- Security Information Reports
SLUR	- Second Level Undervoltage Relays
SM	- Shift Manager
SP	- Surveillance Procedure
SR	- Surveillance Requirement
SRO	- Senior Reactor Operator
SSC	- System, Structure or Component
SSUD	- Shift Supervisor on Duty
TC	- Temporary Change
TDBD	- Topical Design Basis Document
TS	- Technical Specification
URI	- Unresolved Item
VIO	- Violation
WI	- Work Instructions
WR	- Work Request
WSI	- Welding Services, Inc.