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

Report No.: 50-302/95-20

Licensee: Florida Power Corporation
3201 34th Street, South
St. Petersburg, FL 33733

Docket No.: 50-302 License No.: DPR-72

Facility Name: Crystal River 3

Inspection Conducted: November 5 through December 16, 1995

Inspector: f. S. Melh 12/21/95
R. Butcher, Senior Resident Inspector Date Signed

Accompanying Inspectors:

T. Cooper, Resident Inspector
G. Hopper, Reactor Engineer, Region II
C. Osterholtz, Examiner, Region III
P. Kellogg, Senior Project Manager, Region II

Approved by: K. Landis 12/21/95
K. Landis, Branch Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

These inspections were conducted by the resident and Regional inspectors in the areas of plant operations, surveillance observations, maintenance observations, plant support, self assessment, on-site follow-up and in-office review of written reports of non-routine events and 10 CFR Part 21 reviews, maintenance activities followup, engineering activities follow-up, and operator requalification program. Numerous facility tours were conducted and facility operations observed. Backshift inspections were conducted on November 6, 10, 13, 15, 24, 28, 29, December 8, and 9, 1995.

Results:

During this inspection period, the inspectors had comments and findings in the following areas:

Plant Operations:

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe plant operations.

A weakness was identified regarding the lack of a program to require the shift supervisors to document, upon entry into LCO 3.0.6, that they had conducted an evaluation to consider the Safety Function Determination Program requirements as specified in TS 5.6.2.16. (paragraph 1.6.2.4)

An unresolved item** was identified regarding an inadequate procedure to establish high pressure injection flow which could result in pump runout. Unresolved item 50-302/95-20-01, Inadequate procedure for establishing High Pressure Injection flow. (paragraph 1.1.2.2)

A strength was identified regarding the prompt recognition and timely response by the operators when a maintenance technician stroked the wrong valve in the decay heat system. (paragraph 1.3.2)

Significant improvements were made in operator training over the past year to correct previously identified deficiencies. The inspectors determined that the requalification program was capable of ensuring safe power plant operation by adequately evaluating the operator's and crew's mastery of the training objectives. (paragraph 2.1)

Maintenance:

A non-cited violation, 50-302/95-20-02, was identified regarding the failure to follow instructions resulting in the stroking of the wrong valve. (paragraph 1.3.2)

Engineering:

A weakness was identified in that corrective actions committed in LER 50-302/95-014 was different than the corrective actions submitted in response to deviation 50-302/95-16-05 and a supplement to the LER was not issued until corrective action steps in the original Licensee Event Report had been missed. (paragraph 1.6.2.1)

Plant Support:

The identification by the security officer of the vibrating conduit and the prompt notification of the operations personnel is considered a strength. (paragraph 1.4.2)

**Unresolved items are a matter about which more information is required to determine whether they are acceptable or may involve violations or deviations.

REPORT DETAILS

1.0 Persons Contacted

1.1 Licensee Employees

W. Bandhauer, Nuclear Shift Manager
*G. Boldt, Vice President Nuclear Production
J. Campbell, Manager, Nuclear Plant Technical Support
*R. Davis, Manager, Nuclear Plant Maintenance
B. Gutherman, Manager, Nuclear Licensing
*#G. Halnon, Manager, Nuclear Plant Operations
*#B. Hickle, Director, Nuclear Plant Operations
#S. Johnson, Acting Director, Nuclear Operations Training
*L. Kelley, Director, Nuclear Operations Site Support
*K. Lancaster, Manager, Nuclear Projects
#J. Lind, Manager, Nuclear Operations Training
*G. Longhauser, Manager, Security
W. Marshall, Nuclear Shift Manager
P. McKee, Director, Quality Programs
*R. McLaughlin, Nuclear Regulatory Specialist
B. Moore, Manager, Work Controls
*S. Robinson, Manager, Nuclear Quality Assurance
W. Rossfeld, Manager, Site Nuclear Services
#J. Smith, Supervisor, Nuclear Operations Training
J. Springer, Supervisor, Nuclear Simulator Training
W. Stephenson, Nuclear Shift Manager
F. Sullivan, Nuclear Shift Manager
G. Wilson, Nuclear Shift Manager
#R. Widell, Director, Nuclear Operations Training

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

1.2 NRC Resident Inspectors

*#R. Butcher, Senior Resident Inspector
*T. Cooper, Resident Inspector

*Attended residents exit interview on December 16, 1995
#Attended Operator Requalification exit interview on November 17, 1995.

1.3 Other NRC Personnel on Site

G. Hopper, Reactor Engineer, Region II
C. Osterholtz, Examiner, Region III
P. Kellog, Senior Project Manager, Region II
R. Schin, Reactor Inspector, Region II
C. Rapp, Reactor Inspector, Region II
K. Landis, Branch Chief, Region II

2.0 Other NRC Inspections Performed During This Period

2.1 Mr. G. Hopper, Examiner, Region II, and Mr. C. Osterholtz, Examiner, Region III were on site November 13 through November 17, 1995 to conduct an inspection of the licensed operator requalification program. The results of this inspection is included as attachment 2 of this report.

2.2 Mr. P. Kellogg, Senior Project Manager, Region II, was on site the week of December 4, 1995 to act for the resident inspectors who were attending a resident inspectors meeting in Region II. The results of his inspection efforts are included in attachment 1 of this report.

2.3 Mr. P. Kellogg, Senior Project Manager, Mr. R. Schin, Reactor Inspector, and Mr. C. Rapp, Reactor Inspector, Region II, were on site the week of December 11, 1995 to perform a follow-up inspection on Makeup Tank issues. The results of this inspection will be included in Inspection Report 50-302/95-22.

2.4 Mr. K. Landis, Branch Chief, Region II, was on site December 14 and 15, 1995 to coordinate with the resident inspectors, tour the reactor site, and discuss regulatory issues with the licensee. No inspection report will be issued for this site visit.

3.0 Plant Status

At the beginning of this reporting period, Unit 3 was operating at 100% power and had been on line since October 15, 1995. No major plant evolutions occurred during this assessment period.

4.0 Exit Interview Summary

The inspection scope and findings were summarized with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
URI	50-302/95-20-01	Open	Inadequate Procedure for Determining High Pressure Injection Flow. (paragraph 1.1.2.2)
NCV	50-302/95-20-02	Closed	Failure to follow procedure for the stroking of DHV-12 resulting in the inadvertent stroking of DHV-43. (paragraph 1.3.2)
LER	50-302/95-014	Open	Technical Support Center Air Flow Deviates From Acceptable Flow

			Resulting in Operation Outside the Design Basis. (paragraph 1.6.2.1)
LER	50-302/95-020	Closed	Improper Downgrade of Backup Lube Oil Pump Creates Reliance on Non-Safety Equipment Resulting in Operation Outside the Design Basis. (paragraph 1.6.2.1)
LER	50-302/95-022	Closed	System Flow Balancing Identifies Low Flow to Components Resulting in Operation Outside Design Basis. (paragraph 1.6.2.1)
LER	50-302/95-024	Closed	Annubar/Flow Tap Orientation Causes Seismic Qualification Concerns Resulting in Operation Outside the Design Basis of the Plant. (paragraph 1.6.2.1)
IFI	50-302/92-19-01	Closed	Resolution of Problem reports POPR-90-0058, CMPR-91-0008, and POPR 93-218. (paragraph 1.8.2.2)
IFI	50-302/92-22-02	Closed	Weakness in the Procedure Change Program. (paragraph 1.8.2.3)
IFI	50-302/94-23-01	Closed	Inadequate size and quality of the JPM bank. (paragraph 2.2.2.1)
IFI	50-302/94-23-02	Closed	Ineffective identification of individual operator areas for retraining. (paragraph 2.2.2.2)
URI	50-302/94-12-01	Closed	Verification Process for Post Maintenance Testing. (paragraph 1.7.2)
URI	50-302/95-14-04	Closed	Available Emergency Feedwater for Natural Circulation Cooldown. (paragraph 1.8.2.1)
VIO	50-302/93-27-01	Closed	Failure to Perform Tendon Surveillance Inspection in Accordance with Procedure Requirements. (paragraph 1.8.2.4)
VIO	50-302/94-11-01	Closed	Failure to Follow ISI Procedure Requirements. (paragraph 1.8.2.5)

Attachment 1
Resident's Inspection
(R. Butcher, T. Cooper, and P. Kellogg)

1.1.0 Plant Operations (71707)

1.1.1 Inspection Scope

Throughout the inspection period, facility tours were conducted to observe operations and maintenance activities in progress. The tours included entries into the protected areas and the radiologically controlled areas of the plant. During these inspections, discussions were held with operators, health physics and instrument and controls technicians, mechanics, security personnel, engineers, supervisors, and plant management. Some operations and maintenance activity observations were conducted during backshifts. Licensee meetings were attended by the inspector to observe planning and management activities. The inspections confirmed FPC's compliance with 10 CFR, Technical Specifications, License Conditions, and Administrative Procedures.

1.1.2 Observations and Findings

1.1.2.1 Emergency Feedwater Pump System Outage

On November 7, 1995 at 3:00 a.m., EFP-2 was removed from service for a planned system outage. The plant entered TS 3.7.5, Emergency Feedwater (EFW) System, Condition B at that time. The main purpose for the system outage was to correct three concerns; valve operator torque switch roll pin failures, increasing pump and turbine lubricating oil contaminates, and pump packing failures. A Part 21 issued by the Limitorque Corporation on March 23, 1994 recommended replacement of the roll pin in certain types of valves at the discretion of the utility. EFV-32, a motor driven feedwater isolation valve for the EFP-2 discharge line, was affected by the Part 21. Results from recent oil analysis indicated there was an urgent need to change the lubricating oil in the turbine and pump inboard and outboard bearing oil reservoirs. Emergency feedwater pump packing failures and excessive leakoff have been a concern for several years. Following an April 1995 system outage on EFP-1, the installation of Chesterton Style 2 packing reduced overall packing leakage. The expected improvement for EFP-2 would be reduced overall packing leakoff and improved packing reliability and longevity.

The residents reviewed the documentation of the licensee's safety benefit evaluation that is required by AI-255, Safety Benefit Evaluation. The evaluation included a written justification for the determination of a safety benefit for the system outage, a system outage schedule, and a memorandum that documented the safety analysis for system outages for the time period July 1, 1995 through June 30, 1996. The EFP-2 outage was stated to have little effect on core damage risk with the core damage probability being in the Non-Risk-Significant category. The residents found the documentation to be complete and comprehensive.

EFP-2 was restored to service, the post maintenance test completed and the TS action statement exited at 9:45 p.m. on November 8, 1995.

1.1.2.2 Limiting HPI Flow to Prevent Pump Runout

The licensee's EOP Enhancement Program identified a discrepancy in the method to limit HPI flow. EOP-14, EOP Enclosures, Enclosure 2, LPI Low Flow Control, step two, instructs the operators to throttle HPI flow to 540 gpm/pump. EOP-13, EOP Rules, Rule 2, discusses HPI control and instructs the operator to isolate the MUP recirculation path. These Rules are to prevent HPI pump runout which occurs at 575 gpm. The flow instruments in the HPI lines are safety related and qualified as RG 1.97 instruments with a total instrument error of approximately 35 gpm for one pump operation. If the total pump flow of 540 gpm (indicated) was going through the HPI lines with a 35 gpm error, the actual flow could be at the pump runout limit of 575 gpm. However, some HPI flow (normally a total of 40 gpm) is going through the RCP seal injection path which is not discussed in the EOPs. Flow indicator MU-27-FI is used to monitor seal injection flow, however the current instrument string for MU-27-FI is non-safety related and MU-27-FI is a non-RG 1.97 instrument. PR 95-0227, Lack of Qualified RCP Seal Injection Flow Instrumentation, was issued on November 7, 1995 to document this discrepancy and any required corrective actions. This issue was reported to the NRC on November 10, 1995 at 1:43 p.m. under 10 CFR 50.72(b)(2)(iii)(D) since the additional 40 gpm RCP seal flow could lead to HPI pump run out, which could cause HPI pump damage.

STI 95-0061 and OSB 9511.03 were issued to alert the operators to the potential problem of HPI pump runout. The operator must consider the following when operating HPI. Total HPI flow = HPI flow + Normal MU flow + Seal Injection flow + MUP recirculation flow. The existing procedures did not address how to handle the RCP seal injection flow. STI 95-0061 directs the operators to isolate the RCP seal injection line whenever full HPI is required. This interim corrective action ensures the HPI pumps do not exceed the pumps runout limits. The licensee has data from the RCP vendor, Byron Jackson, that the RCP pump and seal cartridge are designed to operate continuously without seal injection flow assuming normal CCW flow is maintained.

Subsequent to notification of the NRC of this finding, the licensee determined that HPI pump runout may not be a credible event for the existing system configuration. A hydraulic computer model of the HPI configuration will be run to resolve the HPI pump runout concerns. A supplement to LER 50-302/95-026 will be submitted when the results of this analysis is known. Until the licensee has completed their analysis, this issue will be identified as URI 50-302/95-20-01, Inadequate procedure for determining HPI flow.

1.1.2.3 Changes to the Environs around CR-3

On November 15, 1995 at the licensee's Plan of the Day meeting, the licensee discussed the status of FPC's plans to run a natural gas pipe line to the fossil units located at the Crystal River site. In addition to the Nuclear Plant (CR-3), there are four fossil units located at the CR site. The CR-3 management had previously expressed a concern to fossil plant management regarding a natural gas pipe line due to the proximity to CR-3. Nuclear Engineering was presently involved in the preliminary design of the pipe line routing. At this time, the engineering plans are scheduled to be complete by February 1996 and the pipe line installation is scheduled to be complete by September 1996.

The issue of changes to the environs around a nuclear facility was the subject of a Temporary Instruction (TI 2515/112, Licensee Evaluation of Changes to the Environs Around Licensed Reactor Facilities) and was the subject of NRC IR 50-302/92-24. The licensee has no formal program to evaluate changes to the environs and to update the FSAR. The inspectors discussed this issue with the licensee and referred the licensee to previous documentation and references on this subject. The residents notified the NRR Project Manager and Region II supervision of the licensee's plans for a natural gas pipeline. The inspectors contacted the licensee's Radiological Emergency Planning group on November 27, 1995 and was informed that they had just became aware of the plans for a gas pipeline for the CR-3 site. A 10 CFR 50.59 evaluation for a possible unreviewed safety question had not been initiated at that time. The residents are continuing to follow the progress of this new pipeline.

1.1.2.4 Safety Function Determination Program

TS 5.6.2.16, Safety Function Determination Program (SFDP), requires that the licensee have a program that, upon entry into LCO 3.0.6, requires an evaluation be made to determine if a loss of safety function exists. The SFDP is required to contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's completion time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

The residents determined that the licensee does not have a formal SFDP for use when entering LCO 3.0.6 and there is no documentation that the SSOD has evaluated the factors noted in TS 5.6.2.16. A SFDP was discussed in NOD-14, Evaluating Operability and Determining Safety Function Status, which was superseded by CP-150, Identifying and Processing Operability Concerns, which does not discuss the SFDP. Neither procedure required the NSSs document that they had considered the four requirements noted above when entering LCO 3.0.6. Discussions with operations personnel indicate that they understood the requirements specified in LCO 3.0.6 and possibly mentally applied those requirements although there is no documentation to show the requirements of TS 5.6.2.16 were evaluated when removing supporting systems from service. The failure to have a program to require the shift supervisors to document, upon entry into LCO 3.0.6, that they had conducted an evaluation to consider the Safety Function Determination Program requirements as specified in TS 5.6.2.16 is considered a weakness. The licensee is developing an operations procedure that will document the NSS's considerations of the requirements specified in TS 5.6.2.16.

1.1.2.5 Emergency Feedwater Piping Leakage

On December 6, 1995, a building operator, while performing his routine rounds, observed water leaking from the ground in a trench which carries temporary power cables on the south west berm. Samples were taken of the water and morpholine and hydrazine concentrations were found consistent with the water in EFT-2, the emergency feedwater storage tank. Two lines which have the potential of carrying water from the tank are in the vicinity of the trench. The eight inch suction line from the tank to the pumps and the one and one-half inch recirculation line from the pumps to the tank both run under the trench in that vicinity.

The licensee reviewed the data on the makeup to EFT-2 and was able to identify approximately 14 gallons per hour leakage from the tank. Approximately half on that leakage was identified as valve packing leaks and pump packing leaks. The remainder, approximately six to seven gallons per hour, is attributed to leakage through the hole in the piping.

On Friday, November 8, 1995 the licensee excavated the pipes near the suspected leak. The recirculation line was found to have a small leak which appeared to have been caused by external, galvanic corrosion. The licensee speculated that the carbon steel line, which is coated to prevent corrosion, might have had the coating damaged during the installation of the cable trench, providing a path for galvanic corrosion.

The licensee developed a proposed corrective action plan per the guidance in GL 90-05, Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping, which they presented to the NRC via telephone communications on December 9, 1995. A repair meeting the ASME code requirements would require rendering both trains of emergency feedwater inoperable. This is a highly undesirable situation. The licensee has proposed making a non-code temporary repair, consisting of a patch and a rig to maintain the integrity of the pipe in case of a catastrophic failure of the pipe. The piping will have a permanent code repair performed during the upcoming refueling outage, scheduled to start in February, 1996. A submittal to the NRC was made on December 11, 1995 requesting approval of this non-code repair.

1.1.2.6 Decay Heat Closed Cycle Cooling System Outage for Flow Balancing

On December 13, 1995, a system outage began to perform flow balancing of the A Train of the DC system. The licensee entered TS 3.7.8, Action statement A at 11:00 am on December 13, 1995. The as-found conditions readings were taken and all flows were found within acceptable values. One local instrument was found, at that time, that deviated from the ultrasonic flow instrumentation being used to conduct the test. That instrument was calibrated and restored to service.

The inspectors reviewed the outage justification prepared by engineering on December 6, 1995. No problems were observed with the justification or with the purpose of the outage, which was to balance the DC flow available to MUP-1A. DC is the alternate cooling water supply to the MUP-1A and the licensee had determined that it was not properly balanced to supply flow to the pump. The proper flow balancing will also assure that the components receive adequate cooling water flow to account for any future pump degradation.

1.1.3 Results

One unresolved item and one weakness were identified. Violations and deviations were not identified.

1.2.0 Surveillance Observations (61726)

1.2.1 Inspection Scope

The inspectors observed TS required surveillance testing and verified that the test procedures conformed to the requirements of the TSs; testing was performed in accordance with adequate procedures; test instrumentation was calibrated; limiting conditions for operation were met; test results met acceptance criteria requirements and were reviewed by personnel other than the individual directing the test; deficiencies were identified, as appropriate, and were properly reviewed and resolved by management personnel; and system restoration was adequate. For completed tests, the inspectors verified testing frequencies were met and tests were performed by qualified individuals.

1.2.2 Observations and Findings

The inspectors witnessed/reviewed portions of the following test activities:

SP-344A, RWP-2A, SWP-1A, and Valve Surveillance; the inspectors witnessed the performance of this procedure. The procedure was conducted, in the control room, by a licensed operator and an individual in training for a license. The personnel maintained the procedure in hand and constantly referred to it during the performance of the test. Communications between the personnel performing the test and the operators in the field, and between the test performers and the SROs were good. No problems were observed.

SP-340E, DHP-1B, BSP-1A and Valve Surveillance; the inspectors witnessed the performance of this test following the completion of the B ECCS system outage. The test was conducted adequately and no problems were observed.

1.2.3 Results

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the TSs.

Violations or deviations were not identified.

1.3.0 Maintenance Observations (62703)

1.3.1 Inspection Scope

Station maintenance activities of safety-related systems and components were observed and reviewed to ascertain they were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and in conformance with the TSs.

The following items were considered during this review, as appropriate: LCOs were met while components or systems were removed from service; approvals were obtained prior to initiating work; activities were accomplished using approved procedures and were inspected as applicable; procedures used were adequate to control the activity; troubleshooting activities were controlled and repair records accurately reflected the maintenance performed; functional testing and/or calibrations were performed prior to returning components or systems to service; QC records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were properly implemented; QC hold points were established and observed where required; fire prevention controls were implemented; outside contractor force activities were controlled in accordance with the approved QA program; and housekeeping was actively pursued.

1.3.2 Observation and Findings

The inspectors witnessed several work packages being performed during the emergency feedwater outage on November 7, 1995.

- WR 311808 was performed to validate VOTES measurements on the steam supply valve, ASV-5, to the turbine driven pump, EFP-2. The inspectors verified that the work packages were in order, that approvals had been obtained, that the procedures referenced by the WR were included in the package, and that the electrical technicians were knowledgeable about the task being performed. The inspectors witnessed the task being performed and observed no deficiencies. The post maintenance cleanup was completed, with the area left in good condition.

- WR 320802 was performed by the electrical maintenance department, replacing the torque switch on EFV-32. The inspectors reviewed the work package prior to the beginning of the maintenance and verified that all of the documentation was in order. The technicians were knowledgeable in their task assignments and performed the work with a minimum of problems. The inspectors verified that the area was adequately cleaned following the completion of the maintenance.

- WR 330380 was written to drain and replace the lubricating oil in EFP-2 pump and WR 330381 was written to drain and replace the lubricating oil in EFP-2 turbine. The inspectors reviewed the paperwork prior to the beginning of the work and verified that the systems were considered to be safety-related. The proper approvals were obtained before the work began and the area was staged for the work before the work began. The inspectors observed the task and verified that the task proceeded as anticipated. A slight amount of suspended particles were observed in the pump oil samples. Component engineers were present for the sampling and they inspected the inside of the oil casing with a small camera probe. No corrosion or damage was observed on the bearings, but a thin corrosion layer was observed on the inside of the casing. The engineers concluded that the corrosion layer was the source of the suspended solids and that pump integrity was not jeopardized.

On the midnight shift on November 16, 1995, the licensee observed that the signals coming from the EFIC C cabinet for the B OTSG high and low levels were spiking at a rapid interval. During the performance of SP-146A, EFIC Monthly Functional Test, on November 16, 1995 the vector valve control circuit for EFV-11 was found to be inoperable. The licensee declared the EFIC C channel to be inoperable at 10:30 p.m. on November 16, 1995. After a thorough troubleshooting, the licensee identified a 15 Vdc power supply, PS 1, in the EFIC C cabinet was the cause of both problems. The licensee replaced the power supply and declared the EFIC C channel operable after the performance of SP-146A, EFIC Monthly Functional Test, During Modes 1,2,3. The TS Action Statement was exited at 5:30 a.m. on November 17, 1995.

On November 17, 1995 the licensee noted that four memory lights were illuminated on the EFIC D channel. Since the bistables in the EFIC cabinets automatically reset, the memory lights are the only indication that a bistable has tripped. The trip module supplied by the bistables had not tripped. The licensee surmised that the memory lights being illuminated without the trip modules being activated indicates that either the bistables tripped and reset rapidly enough that the trip module did not actuate, or just the lights had been activated. Due to previous anomalous conditions, the EFIC D channel has been being monitored by a data acquisition computer for several months. The licensee reviewed the data from this system and determined that one of the 5 volt power supplies, PS 6, was supplying intermittent spikes to the system. This power supply provides the reference power for the bistable set points. The licensee decided to replace this power supply, perform SP-146A on this channel, and wait for 24 hours to see if any additional anomalies were detected prior to declaring the channel operable. The licensee entered the TS action statement at 7:28 p.m. on November 17, 1995 and exited at 1:17 a.m. on November 18, 1995.

On November 28, 1995 the licensee began a system outage on the B ECCS train, at 5:35 a.m. The licensee entered the TS action statements for the DHP-1B, BSP-1B, RWP-2B, RWP-3B, and MUP-1C. The inspectors witnessed several work packages being performed during this outage, including:

- WR NU 0322199, repaired the leaking pressure instrumentation, DH-35-PI, on DHP-1B. The inspectors witnessed the preparations for the task and the replacement of the instrument. The work package was reviewed by the inspectors and all approvals and reviews were completed prior to the beginning of the work. No problems were identified by the inspectors during the maintenance.

- WR NU 0329001, the inspectors witnessed the licensee cleaning the 1B DC heat exchanger. The inspectors witnessed the venting and draining of the system, the disassembly of the heat exchanger, and the cleaning process, using brushes propelled by water under pressure. The inspectors reviewed the work package and verified that all approvals had been received, the appropriate referenced procedures were included and that the technicians adhered to the directions. No problems were identified.

- WR NU 0329962, replaced a spool piece on the discharge of DCHE-1B. This section of piping was identified as having significant wall thinning at the bend in the piping. The inspectors witnessed the removal of the old spool piece. The inspectors had observed the draining of the system prior to the beginning of the work, but noted that a significant amount of water was still present in the piping when disassembly began. This water is demineralized water used to maintain the heat exchanger in wet layup. The inspectors reviewed the work package prior to the beginning of the task and identified no discrepancies. No problems were identified.

- WR NU 0329748, replaced the operator on DHV-12. The inspectors reviewed the work package prior to the start of the task and found that all reviews and approvals had been obtained. The as-found MOVATS values were obtained and the old operator was disassembled and removed. The inspectors witnessed the disassembly and removal of the old operator. No problems were identified. Following the replacement of the motor operator, during the performance of the initial MOV testing, the technician inadvertently stroked the DHV-43 valve instead of the DHV-12 valve. This valve is the isolation valve for the DHP suction from the RB sump. Due to the lineup in place for the maintenance activities, no water drained from the system. As soon as the valve started to move, the operators recognized what the technician had done and when the valve had completed its stroke, the operators returned it to its original position. The alertness and quick actions on the part of the operator is considered a strength.

TS 5.6.1.1 and Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, requires that instructions be developed and adhered to for safety related activities, including stroke testing of safety related valves. Contrary to the above, on November 29, 1995, a maintenance technician failed to follow the approved work request and stroked the wrong valve. This failure to follow the procedure is a violation. However, due to the prompt response by the operators and the fact that no water was moved during the stroking of this valve, the significance is greatly reduced. Therefore, the criteria of section VII.B of the Enforcement Policy are satisfied and this is a non-cited violation, NCV 50-302/95-20-02, Failure to follow procedure for the stroking of DHV-12 resulting in the inadvertent stroking of DHV-43.

For all of these tasks, the inspectors observed that systems engineers, component engineers, maintenance supervisors, and maintenance managers were present. Good interfacing was observed between the involved groups; operations, maintenance, and engineering.

1.3.3 Results

For those maintenance activities observed, the inspectors determined that the activities were conducted in a satisfactory manner and that the work was properly performed in accordance with approved maintenance work orders. One non-cited violation was identified regarding the failure to follow procedure resulting in the stroking of the wrong valve.

1.4.0 Plant Support (71750)

1.4.1 Inspection Scope

Radiation protection control activities were observed to verify that these activities were in conformance with the facility policies and procedures, and in compliance with regulatory requirements.

In the course of the monthly activities, the inspector included a review of the licensee's physical security program.

The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital areas access controls; searching of personnel, packages, and vehicles; badge issuance and retrieval; escorting of visitors; patrols; and compensatory posts.

Fire protection activities, staffing, and equipment were observed to verify that fire brigade staffing was appropriate and that fire alarms, extinguishing equipment, actuating controls, fire fighting equipment, emergency equipment, and fire barriers were operable.

1.4.2 Inspection Observations and Findings

The observations in the health physics program included:

- Entry to and exit from contaminated areas, including step-off pad conditions and disposal of contaminated clothing;

- Area postings and controls;

- Work activity within radiation, high radiation, and contaminated areas;

- RCA exiting practices;

- Proper wearing of personnel monitoring equipment, protective clothing, and respiratory equipment; and

- NRC form 3 and NOVs involving radiological working conditions were posted in accordance with 10 CFR 19.11.

Effluent and environmental monitoring was observed to determine that radiation and meteorological recorders and indicators were operable with no unexplained abnormal traces evident. Other observations verified that control room toxic monitors were operable and that plant chemistry was within TS and procedural limits.

In addition, the inspector observed the operational status of protected area lighting, protected and vital areas barrier integrity, and the security organization interface with operations and maintenance.

On November 15, 1995, a security officer noticed an electrical conduit that was vibrating on the heater bay of the turbine building. He promptly notified the SSOD. This conduit was rubbing on the air line going to HDV-53, which controls heater drains going to the deaerator from the 5A feedwater heater. If the air line to this valve had ruptured, the valve would have failed open and a significant transient would have occurred. The security force at the site is trained to observe both security matters and off normal operating conditions. The identification by the security officer of the vibrating conduit and the prompt notification of the operations personnel is considered a strength.

1.4.3 Inspection Results

The implementation of the plant support program observed during this inspection period were proper and conservative.

Violations or deviations were not identified.

1.5.0 Self Assessment (40500)

1.5.1 Inspection Scope

The licensee routinely performs Quality Program audits of plant activities as required under its QA program or as requested by management. To assess the effectiveness of these licensee audits, the inspectors examined the status, scope, findings and recommendations of the audit reports.

1.5.2 Inspection Observations and Findings

1.5.2.1 Audit 95-10-PCMT

The inspectors reviewed and discussed with the licensee the results of Quality Assessments Audit, 95-10-PCMT, for the Procurement area. The audit resulted in two findings being issued, for which PRs were written. Ten recommendations were identified, which resulted in three PCs being issued. The auditors also identified six strengths in the procurement area. Several of the audit recommendations were issued due to evidence of poor safety culture. According to the audit report, several groups seemed to feel that they were not part of the Nuclear Operations team and seemed to not be sure of the correct programs to follow, such as following AI-2001, Control of Consumable Chemicals. The inspectors verified that the licensee management was aware of the findings and recommendations and that appropriate corrective actions are being developed.

No additional NRC follow-up will be taken on the findings referenced above because they were identified by the licensee's audit program and corrective actions have either been completed or are currently underway. PRs were initiated on the findings and plant management is aware of the findings.

1.5.2.2 Licensee's Corrective Action Plan

On November 15,1995 the inspectors attended an All Hands Meeting that licensee management conducted as part of the actions outlined in their Corrective Action Plan. That plan was discussed in meetings with the NRC on March 1, 1995, and August 25, 1995; and was documented in the Corrective Action Plan Meeting Summary dated September 7, 1995. The licensee plans to continue to conduct the All Hands Meetings on a periodic basis to enhance communications. Several meetings were held in order for all employees to have the opportunity to attend. The meeting covered the following subjects:

- Regulatory Performance
- Human Performance
- Plant Performance
- Financial Performance
- Incentives for Personnel Performance
- Question and Answer Period

The inspectors considered the meetings beneficial for improved communications.

1.5.3 Inspection Results

Violations or deviations were not identified.

1.6.0 Onsite Follow-up and In-Office Review of Written Reports of Non-routine Events and 10 CFR Part 21 Reviews (92700)

1.6.1 Inspection Scope

The Licensee Event Reports and/or 10 CFR Part 21 Reports discussed below were reviewed. The inspectors verified that reporting requirements had been met, root cause analysis was performed, corrective actions appeared appropriate, and generic applicability had been considered. Additionally, the inspectors verified the licensee had reviewed each event, corrective actions were implemented, responsibility for corrective actions not fully completed was clearly assigned, safety questions had been evaluated and resolved, and violations of regulations or TS conditions had been identified. When applicable, the criteria of 10 CFR Part 2, Appendix C, were applied.

1.6.2 Inspection Observations and Findings

1.6.2.1 LER Review

(Closed) LER 50-302/95-020, Improper Downgrade of Backup Lube Oil Pump Creates Reliance on Non-Safety Equipment Resulting in Operation Outside Design Basis. On October 31, 1995 the licensee had completed installing a plant modification that allowed the safety related ac lube oil pumps to continue to support MUP operation following all accident conditions. The licensee's corrective action was addressed in paragraph 1.1.2.2 in IR 50-302/95-18 and NCV 50-302/95-18-01 was issued. This LER is closed.

(Closed) LER 50-302/95-022, System Flow Balancing Identifies Low Flow to Components Resulting in Operation Outside Design Basis. The licensee's LER describes the corrective actions taken and planned to resolve this issue. This issue was discussed in IR 50-302/95-18 and was identified as NCV 50-302/95-18-02. The B train of DC flow has been correctly adjusted per the revised procedure and the A train flow is scheduled to be accomplished prior to January 5, 1996. This LER is closed.

(Open) LER 50-302/95-014, Technical Support Center Air Flow Deviates From Acceptable Flow Resulting in Operation Outside the Design Basis. This LER was written regarding the Technical Support Center ventilation system being in a condition outside of the design basis. The TSC ventilation system was declared inoperable on August 18, 1995. Deviation 50-302/95-16-05 was issued to address this problem. Additional corrective action 2, in the LER, stated that a new procedure would be written and issued by November 15, 1995 to enhance the directions for performing flow balances. Subsequently, the licensee decided to not issue this new procedure.

In the deviation response, in a letter dated November 9, 1995, to the NRC, corrective steps that will taken to avoid further deviations, step 1, the licensee stated that procedures will be revised to provide lineup and test points for the ventilation emergency mode of operation. These revisions would be completed by December 15, 1995. These procedures are different than the one addressed in the LER. No mention in the deviation response was made to creating a new procedure for the flow balancing. The corrective action in the LER was not completed by the schedule date, nor was a revised LER with a revised corrective action plan, submitted until December 1, 1995. For the same issue, the deviation response and the LER have different corrective action plans. The inconsistencies between the two corrective action plans and the late supplement to the LER is identified as a weakness.

This LER remains open.

(Closed) LER 50-302/95-24, Annubar/Flow Tap Orientation Causes Seismic Qualification Concerns Resulting in Operation Outside the Design Basis of the Plant. The LER describes in detail the issue discussed in NCV 50-302/95-18-06. The inspectors verified that the corrective actions described in the LER are either complete or are scheduled to be completed prior to the need for the procedure to be performed again. Actions to prevent recurrence include the replacement of the spool piece with the annubar attached. This MAR has been developed and is scheduled to be completed by June 30, 1996. The actions are completed or are scheduled to be completed. This LER is closed.

1.6.2.2 Spent Fuel Pool Cooling Concerns

Recently, an issue was raised at Millstone 1 regarding the adequacy of the SF pool cooling system design. The issue concerned the capability of the SF pool cooling system assuming that a full core was off-loaded versus only one third of the core, and considering a single failure in the SF pool cooling system occurred. Specifically, the SRP, dated 1981, indicates that the analysis for SF pool cooling should take into account a normal core off-load (normally one third of the core) and a single failure, while still keeping the SF pool temperature less than or equal to 140 degrees F. The SRP also indicates that the system should be able to keep the SF pool from boiling with a full core offload without considering a single failure. Based on this information, the residents reviewed the adequacy of the CR-3 spent fuel pool design with the current full core off-load practice.

The residents reviewed the FSAR, Chapter 9.3, Spent Fuel Cooling System, revision 14, and the Enhanced Design Basis Document, Spent

Fuel Cooling System, revision 3. The following comments are from the referenced documents:

Normal Core Offload (1/3 of the core)

- FSAR, paragraph 9.3.1 - The SF pool cooling system is designed to maintain the SF pool water temperature below 128 degrees F based on the heat load generated from 1180 fuel assemblies which have been discharged to the spent fuel pool as a result of 19 core refuelings. A time interval of 150 hours was assumed between reactor shutdown and core discharge.

- FSAR, paragraph 9.3.1 - When aligned for spent fuel cooling, the DH system is adequate for maintaining the spent fuel water temperature below 140 degrees F. This is based on the conditions noted above.

- FSAR, paragraph 9.3.2.1.1 - The normal operation of the SF cooling system serves two main functions. The first is to maintain the SF pool water at temperatures of approximately 128 degrees F or less with normal refueling offloads that fill the pool with both pumps and coolers operating.

- Enhanced Design Basis Document - The structural integrity of the spent fuel pools is considered adequate for a steady state water temperature of 160 degrees F with water in both pools.

Full Core Offload

- FSAR, paragraph 9.3.2.1.2, Refueling Conditions - Normally one third of the core will be discharged to the pool. Assuming the conditions noted in FSAR paragraph 9.3.1, when a full core is discharged, the DH system will maintain the spent fuel pool temperature below 140 degrees F. If all cooling is lost at the time the spent fuel pool temperature is 140 degrees F, it would take more than eight hours for the pool to start to boil.

- Enhanced Design Basis Document - The maximum spent fuel pool temperature that can be attained with both spent fuel pool cooling loops operational is 157 degrees F. This value is based on the installation of high density racks in each pool, the off-loading of a full core 72 hours following reactor shutdown, and at the end of a two year refueling cycle. For the loss of one spent fuel cooling loop, the pool temperature could exceed 210 degrees F. The minimum time for the pools to reach 190 degrees F is eight hours. (Note - There is a high temperature alarm of 140 degrees F in the spent fuel pools).

Based on the review of the current full core off-load practice and the spent fuel pool cooling capabilities as described in the FSAR and the Enhanced Design Basis Document, the residents did not identify any concerns.

1.6.2.3 10 CFR Part 21 Report on Rosemount Transmitters

On December 11, 1995, the licensee was notified by the manufacturer that Rosemount series transmitters 1154SH9 had a 10 CFR 21 report issued. This report was on the temperature change effect on transmitter accuracy for a 50°F change. The previous specification was (0.15% URL + 0.35% span). As a result of this notification, the specification has changed to (0.25% URL + 0.50% span).

The licensee reviewed the use of these transmitters at the site and determined that this report only affects the EFIC steam generator pressure transmitters, which supply pressure inputs for the atmospheric dump valves and density compensation for OTSG level instrumentation.

The licensee performed a CP-150, Identifying and Processing Operability Concerns, operability determination and determined that the pressure transmitters were conditionally operable, pending completion of a review by engineering. The initial determination concluded that the increased error was still within the design limitations on the components. The inspectors witnessed the operability determination process and were satisfied with the thoroughness and technical basis displayed.

1.6.3 Inspection Results

One weakness was identified.

1.7.0 Maintenance Activities Follow-up (92902)

1.7.1 Inspection Scope

The open items addressed below were inspected to determine that adequate corrective actions have been taken, their root causes have been identified, their generic implications have been addressed, and that the licensee's procedures and practices have been appropriately modified to prevent recurrence.

1.7.2 Inspection Observation and Findings

(Closed) URI 50-302/94-12-01 Verification Process for Post Maintenance Testing

This item concerned the practice of the SSOD signing off on PMT for work closure packages prior to the PMT actually boeing performed. This was being done in cases where the SSOD knew that the PMT was contained in some other PM or SI that was going to be accomplished prior to returning the item to service. This became confusing in the date for the completion of the PMT was before the actual test was performed. CP-113A has been revised and the SSOD signature was removed form the work closure packages as a part of this revision. PMT status and tracking has been assigned to the Work Control group.

1.7.3 Inspection Results

Violations or deviations were not identified.

1.8.0 Engineering Activities Follow-up (92903)

1.8.1 Inspection Scope

The open items addressed below were inspected to determine that adequate corrective actions have been taken, their root causes have been identified, their generic implications have been addressed, and that the licensee's procedures and practices have been appropriately modified to prevent recurrence.

1.8.2 Inspection Observation and Findings

1.8.2.1 (Closed) Unresolved Item 50-302/95-14-04, Available Emergency Feedwater for Natural Circulation Cooldown.

This unresolved item was issued due to the discrepancies in the response to GL 81-21, Sources of Emergency Feedwater for Natural Circulation Cooldown, and the actual available emergency feedwater supplies. By letter dated November 9, 1995 the licensee clarified the available sources of emergency feedwater for a natural circulation cooldown following the implementation of the improved TSs. In that letter, the licensee committed to revise SP-300, Operating Daily Surveillance Log, and SP-306, Weekly Surveillance Log, to ensure the required sources of water are available. Also, the licensee committed to develop guidance to assure that equipment necessary to transfer the necessary water is available. The FSAR will be updated at the next FSAR revision. Based on the information in the licensee's letter, this unresolved item is closed.

1.8.2.2 (Closed) IFI 50-302/92-19-01 Resolution of Problem reports POPR-90-0058, CMPR-91-0008, and POPR 93-218

This item concerned the timing of feedwater valves and reactor building spray valves. The reactor building spray valves were not fast acting and required approximately 51 seconds to open. The feedwater valves were also not fast acting closing in about 50-60 seconds. The feedwater valves upon reviewing the FSAR were never designed to be fast acting. Although this was recognized by the NRC, a Technical Specification time of 31 seconds was specified for the valves which corresponded to the fast closing valves. This error was undetected until POPR-90-0058 was issued to document the issue. The resolution of this item was to remove the incorrect numbers from the TS. The item concerning the Reactor

Building spray valves was resolved by performing an analysis of the time required for the BS system to deliver full flow to the spray headers. The time was analyzed out to 120 seconds and was then re-analyzed at a later time back to 90 seconds. This was more than sufficient time for the valves to open. The analysis was done as the result of an error that was made when the start signal for the BS system was changed to block 6 on the sequencer, thus increasing the time for full flow delivery.

1.8.2.3 (Closed) IFI 50-302/92-22-02 Weakness in the Procedure change Program

This item concerned errors that had been identified prior to revision of a procedure, but not corrected during the revision to the procedure. The specific procedure in question was SP-113, Engineering Reviews. This procedure was issued as Revision 20 and it contained errors that had been pointed out in Revision 19. Revision 16 to AI-400C (New Procedures and Procedure Change Process) strengthened the verification and validation processes for procedures. The independent reviewer process was also strengthened. Engineering procedures are now covered under the controls of AI-400C.

1.8.2.4 (Closed) VIO 50-302/93-27-01 Failure to Perform Tendon Surveillance Inspection in Accordance with Procedure Requirements

This violation concerned several failures to follow SP-182. The failures included the use of the wrong size feeler gauge, a verifications of references were available was not accomplished, the recording of the equipment and measuring devices was not accomplished prior to the start of the surveillance, a bulk filler inspection was not documented and performed, a QC inspection was not done,and QC hold points were missed. The inspector reviewed the licensee's corrective action contained in a letter dated January 24, 1994. These actions were to correct the individual items contained in the Notice of Violation. The procedural deficiencies were corrected and the tendon test was completed utilizing the revised procedure. A review of the controls governing contractor management and supervision was performed and personnel were instructed in contractor supervision. Additionally the licensee required the contractor to identify why the procedural violations occurred and what steps would be taken to ensure that compliance would be achieved during subsequent tests. Based upon the above review and discussions with licensee personnel, this item is closed.

1.8.2.5 (Closed) VIO 50-302/94-11-01 Failure to Follow ISI Procedure Requirements

This item concerned three items of failure to follow ISI procedures. This item was reviewed in IR 95-03. During that inspection the inspector reviewed the changes that had been made as part of the licensees corrective action to the ISI administrative guide. The changes to the ISI administrative guide did not clearly specify the items contained in the letter of response. During this inspection, discussion with the Supervisor of Site Engineering Services for ISI indicated that additional problems had been identified with the ISI administrative guides. A decision was made to delete the ISI Section Manual, containing the administrative guides, and incorporate the requirement in Nuclear Engineering Procedures (NEPs). This change formalizes the program and places more control over the procedures. This change is in progress and the procedures are due to be issued in January of 1996 with training to follow shortly thereafter.

1.8.3 Inspection Results

Violations or deviations were not identified.

Attachment 2

2.1.0 Requalification Program Inspection (71001)

2.1.1 Inspection Scope

The NRC conducted a routine, announced inspection of the licensed operator requalification program during the period November 13-17, 1995. The inspectors reviewed and observed annual requalification examinations conducted by the licensee and conducted inspection activities in accordance with Inspection Procedure 71001. Activities reviewed included examination development and administration, evaluator performance, and remedial training.

2.1.2 Observations and Findings

The inspectors observed the operators performance during simulator scenarios and during administration of Job Performance Measures (JPMs). In addition the inspectors observed evaluation critiques performed by licensee evaluators and critique reviews conducted with the examinees. The inspectors also reviewed the examination results documentation prepared by the licensee evaluators. Written examinations were not reviewed since none were administered during this examination cycle.

The inspectors found that the licensee effectively evaluated both crew and individual performance. The inspectors concurred with the licensee's critique comments of the crews and individuals observed. The inspectors noted that the crew and individual performance evaluations were very detailed and contained much useful information which will be utilized to adjust future requalification training needs. The inspectors also noted that the licensee conducted effective debriefs with the operators on both a crew and individual basis. Post exam critiques at the end of each exam week resulted in documentation of action items which included generic performance issues, procedural problems, enhancements to the training program, etc. The inspectors found this process to be very constructive since it collated and documented training and procedural validation problems that were discovered each week.

The inspectors also conducted interviews of licensed operators to determine their perspectives on the requalification program effectiveness. All operators interviewed indicated that performance standards were clear cut and fully understood. They also indicated that the evaluations were objective and reasonable, and that the training department was fully in touch with their training requirements as operators. All operators indicated that the training department always provided feedback to them on any suggestions or concerns they had concerning their training. Some operators felt that certain training personnel should receive more training on classroom teaching techniques. Additionally, some operators expressed concern that the simulator telephone communications equipment is not modeled exactly like the equipment in the control room.

2.1.3 Results

The inspectors determined that significant improvements were made in the program over past year to correct previously identified deficiencies and that the requalification program was capable of ensuring safe power plant operation by adequately evaluating the operator's and crew's mastery of the training objectives. In addition, the program meets elements (4) and (5) of an SAT-based program as defined in 10 CFR 55.4.

No violations or deviations were identified.

2.2.0 Followup (92901)

2.2.1 Inspection Scope

The inspector reviewed the licensee's actions on previously identified discrepancies.

2.2.2 Observations and Findings

2.2.2.1 (Closed) IFI 50-302/94-23-01: Inadequate size and quality of the JPM bank. This item involved several discrepancies with the licensee's JPMs which included:

a) The JPM cues were too focused and did not allow for evaluation of an operator to locate the appropriate procedure.

b) Many JPMs were simplistic (were not difficult, important or infrequent tasks) and could not really be used to evaluate an operators competence.

c) The JPM bank contained an inadequate amount of alternate path JPMs (6 total).

d) The JPM bank contained an inadequate number of Emergency Plan Classification JPMs (5) and these were being repeated too frequently from one exam week to the next and from year to year.

The inspector reviewed the licensee's corrective actions for the above discrepancies. The inspector found the following items which correlate with those above.

a) JPM initiating cues no longer specify procedures and procedure steps. Most JPMs required the operators to recognize and locate the appropriate procedure.

b) The licensee has improved the quality of the JPMs and recognizes the need for JPMs to be of such quality as to provide meaningful evaluation of an operators competence.

c) The number of alternate path JPMs has been increased from 6/137 to 38/166.

d) The number of Emergency Plan Classification JPMs has been increased from 5 to 29, thereby improving exam security and providing a more meaningful evaluation tool.

2.2.2.2 (Closed) IFI 50-302/94-23-02: Ineffective Identification of individual operator areas for retraining.

The inspectors observed the current method of evaluating both crew and individual operator performance during the operating examinations. The inspectors found that the licensee effectively measured both crew and individual operator performance. The inspectors noted that the crew and individual performance evaluations were very detailed and appropriately documented operator weaknesses. Generic operator performance issues were well documented. The licensee will use these and other inputs as feedback to adjust future requalification training needs. The inspectors also noted that licensee conducted effective debriefs with the operators on both a crew and individual basis. All operators were individually debriefed on their performance of the JPMs and discussed any weaknesses noted with a training manager. Operations management involvement was extensive throughout all phases of the evaluation process.

The inspector concluded that the scope and method of documenting crew and individual performance weaknesses was quite thorough. The facility evaluation team adequately documented operator performance. Evaluation results were as or more conservative than the NRC.

2.2.3 Results

These items are closed.

Acronyms and Abbreviations

ac - Alternating Current
AI - Administrative Instruction
ALARA - As Low as Reasonably Achievable
ASME - American Society of Mechanical Engineers
ASV - Auxiliary Steam Valve
B&W - Babcock & Wilcox
BS - Building Spray
BSP - Building Spray Pump
BWST - Borated Water Storage Tank
CCTV - Closed Circuit Television
CCW - Component Coolig Water
CFR - Code of Federal Regulations
CFT - Core Flood Tank
CFV - Core Flood Valve
CP - Compliance Procedure
dc - Direct Current
DC - Decay Heat Closed Cycle Cooling
DCHE - DC Heat Exchanger
DEV - Deviation
DH - Decay Heat
DHHE - Decay Heat Heat Exchanger
DHP - Decay Heat Pump
DHV - Decay Heat Valve
ECCS - Emergency Core Cooling System(s)
EDBD - Enhanced Design Basis Document
EFIC - Emergency Feedwater Initiation and Control
EFP - Emergency Feedwater Pump
EFT - Emergency Feedwater Tank
EFW - Emergency Feedwater
EFV - Emergency Feedwater Valve
EGDG - Emergency Diesel Generators
EM - Emergency Plan Implementing Procedure
EOP - Emergency Operating Procedure
ES - Engineered Safeguards
ESAS - Engineered Safety Actuation System
F - Fahrenheit
FPC - Florida Power Corporation
FSAR - Final Safety Analysis Report
GL - Generic Letter
gpm - Gallons Per Minute
HP - Health Physics
HPI - High Pressure Injection
I&C - Instrumentation and Control
ICC - Inadequate Core Cooling
ICS - Integrated Control System
IFI - Inspection Followup Item
IR - Inspection Report
ISI - Inservice Inspection
IST - Inservice Test
JCO - Justification for Continued Operation

JPM - Job Performance Measure
Kv - Kilovolt
kw - Kilowatt
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOOP - Loss of Offsite Power
MAR - Modification Approval Record
MCB - Main Control Board
MFW - Main Feedwater
MOV - Motor Operated Valve
MOVATS- Motor Operated Valve Analysis and Test System
MP - Maintenance Procedure
MSV - Main Steam Valve
MU - Make Up
MUP - Make-up Pump
MW - Megawatt
NCV - Non-cited Violation
NEP - Nuclear Engineering Procedure
NOD - Nuclear Operations Department
NOV - Notice of Violation
NPSH - Net Positive Suction Head
NSS - Nuclear Shift Supervisor
NSSS - Nuclear Steam System Supplier
OP - Operating Procedure
OSB - Operations Study Book
OTSG - Once Through Steam Generator
PM - Preventive Maintenance
PMT - Preventive Maintenance Test
PORV - Power Operated Relief Valve
PR - Problem Report
psig - pounds per square inch gauge
QC - Quality Control
QA - Quality Assurance
RB - Reactor Building
RCA - Radiation Control Area
RCP - Reactor Coolant Pump
RCPPM - Reactor Coolant Pump Power Monitor
RCS - Reactor Coolant System
REA - Request for Engineering Assistance
RG - Regulatory Guide
RO - Reactor Operator
RW - Nuclear Services and Decay Heat Seawater
RWP - Nuclear Services and Decay Heat Seawater Pump
SALP - Systematic Assessment of Licensee Performance
SAT - Systems Approach to Training
SF - Spent Fuel
SFPD - Safety Function Determination Program
SG - Steam Generator
SI - Surveillance Instruction
SP - Surveillance Procedure
SR - Surveillance Requirement

SRP - Standard Review Plan
SSOD - Shift Supervisor on Duty
STI - Short Term Instruction
SW - Nuclear Services Closed Cycle Cooling System
SWP - SW System Pump
TI - Temporary Instruction
TMI - Three Mile Island
TS - Technical Specification
URI - Unresolved Item
VIO - Violation
VOTES - Valve Operation Test and Evaluation System
WR - Work Request