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

Report Nos.: 50-250/87-10 and 50-251/87-10

Licensee: Florida Power and Light Company
9250 West Flagler Street
Miami, FL 33102

Docket Nos.: 50-250 and 50-251 License Nos.: DPR-31 and DPR-41

Facility Name: Turkey Point 3 and 4

Inspection Conducted: February 9 - March 9, 1987

Inspectors: B. A. Wilson, for — 4/15/87
D. R. Brewer, Senior Resident Inspector — Date Signed

B. A. Wilson, for — 4/15/87
K. W. Van Dyne, Resident Inspector — Date Signed

B. A. Wilson for — 4/15/87
J. B. MacDonald, Resident Inspector — Date Signed

Approved by: Bruce A. Wilson — 4/15/87
Bruce Wilson, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed direct inspection at the site, including backshift inspection, in the areas of annual and monthly surveillance, maintenance observations and reviews, operational safety, and plant events.

Results: No violations or deviations were identified.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*#C. M. Wethy, Vice President - Turkey Point
#C. J. Baker, Plant Manager-Nuclear - Turkey Point
*F. H. Southworth, Maintenance Superintendent - Nuclear
*#D. A. Chaney, Site Engineering Manager (SEM)
D. D. Grandage, Operations Superintendent and Acting Plant Manager
T. A. Finn, Operations Supervisor
J. Webb, Operations - Maintenance Coordinator
J. W. Kappes, Performance Enhancement Coordinator
R. A. Longtemps, Mechanical Maintenance Department Supervisor
D. Tomasewski, Instrument and Control (IC) Department Supervisor
J. C. Strong, Electrical Department Supervisor
*W. Bladow, Quality Assurance (QA) Superintendent
R. E. Lee, Quality Control Inspector
*M. J. Crisler, Quality Control (QC) Supervisor
J. A. Labarraque, Technical Department Supervisor
R. G. Mende, Reactor Engineering Supervisor
J. Arias, Regulation and Compliance Supervisor
*#R. Hart, Regulation and Compliance Engineer
W. C. Miller, Training Supervisor
P. W. Hughes, Health Physics Supervisor
G. Solomon, Regulation and Compliance Engineer
*#J. Donis, Engineering Department Supervisor
J. J. Zudans, Nuclear Engineering, Human Factors Performance
R. L. Wade, Engineering Department
*W. J. Pike, Safety Engineering Group Engineer
*J. E. Crockford, Operations Training Supervisor
*J. F. O'Brien, Project QC Supervisor
*A. S. Mathes, Quality Control Supervisor
*#J. M. Mowbray, Juno Plant Engineer
#S. L. Wilkie, Juno Plant Engineer

Other licensee employees contacted included construction craftsmen, engineers, technicians, operators, mechanics, and electricians.

*Attended exit interview on March 9, 1987.
#Attended followup exit interview on March 11, 1987.

2. Exit Interview

The inspection scope and findings were summarized during management interviews held throughout the reporting period with the Plant Manager-Nuclear and selected members of his staff. An exit meeting was conducted on March 9, 1987, and a followup meeting was conducted on

March 11, 1987. The areas requiring management attention were reviewed. The licensee felt that the engineering evaluations discussed in paragraph 11 were fully adequate and stated that the additional evaluations performed subsequent to conversations with the NRC were performed as a courtesy and were not required to be performed.

3. In-Office Review of Written Reports of Nonroutine Events (90712)

The following Licensee Event Report (LER) was reviewed and closed based on an in-office review. The inspectors verified that reporting requirements had been met, root cause analysis was performed, corrective actions appeared appropriate, and generic applicability had been considered. In addition, the LER was reviewed for and determined not to require further onsite inspector followup.

(Closed) LER 250/85-06, Fire Suppression Water Source. This LER documents a Technical Specification (TS) surveillance which was performed late and constituted an additional example of the licensee's failure to maintain an effective program for the correction of conditions adverse to quality, (Violation 250,251/86-39-02). This violation is addressed and closed in paragraph 4 of this report.

4. Licensee Actions on Previous Enforcement Matters (92702) and Related Inspection Findings

A review was conducted of the following enforcement issues and inspection findings to assure that corrective actions were adequately implemented and resulted in conformance with regulatory requirements. Verification of corrective action was achieved through record reviews, observation and discussions with licensee personnel. Licensee correspondence was evaluated to ensure that the responses were timely and that corrective actions were implemented within the time periods specified in the reply.

a. Diesel Generator Problems

In December 1985, the licensee informed the NRC staff that an emergency diesel generator (EDG) overload condition would exist if a design basis event were to occur at the Turkey Point site. The concern was that insufficient EDG capacity was available to accommodate the maximum loading levels required for a large break loss of coolant accident in conjunction with the failure of a single EDG and a loss of off site power. In March 1986, based on a refined load analysis, the licensee determined that the EDG load limit would support only single unit operation. Unit 4, which had entered a refueling shutdown in January 1986, remained in cold shutdown pending resolution of the loading problems. An evaluation was performed in accordance with 10 CFR 50.59 to demonstrate that Unit 3 could safely operate and Unit 4 could be safely maintained in cold shutdown while load modifications were performed. On April 2, 1986, a Confirmation of Action Letter (CAL) was issued wherein the licensee and the NRC agreed that a Safety Evaluation (SE) of EDG loading for concurrent operation of

Turkey Point Units 3 and 4 would be completed and approved by NRC prior to the restart of Unit 4.

FPL submitted the results of the SE to the NRC for review on June 13, 1986. AN NRC review of the SE was completed on June 26, 1986, and it was concluded that the SE adequately documented that proposed EDG load modifications would, if effectively implemented, correct the overload problem. The necessary modifications were made in July 1986.

NRC inspections of licensee corrective actions for the overload problem are documented in Inspection Reports 250,251/86-24, April 3-6, and April 16-18, 1986; 250,251/86-25, April 14 - May 12, 1986; 250,251/86-29, April 22-25, 1986; and 250,251/86-34, July 22-26, 1986. During these inspections several issues, including violations, a deviation, unresolved items and inspector followup items were identified. Reviews of these items were performed and corrective actions were implemented prior to the restart of the Unit 4 reactor in August 1986.

The inspection documented in report 250,251/86-34 was performed to verify that the licensee had adequately implemented design changes which reduced the EDG loading to an acceptable level for dual unit operation. Additionally, the inspectors observed engineered safeguards testing during lost of offsite power conditions and observed EDG loading to verify that acceptable levels were not exceeded.

On December 15, 1986, the NRC staff completed a comprehensive SE which concluded that: the EDG loads for various accident conditions had been returned to levels required by the Final Safety Analysis Report (FSAR) and applicable Regulatory Guides; operator actions described in plant procedures were acceptable and were consistent with the accident analysis and emergency operating procedures; the revised containment pressure and temperature analysis was acceptable; and an adequate human factors analysis had been performed. Therefore the corrective actions which were implemented between December 1985 and August 1986 were acceptable. Consequently, the following items are closed.

(Closed) LER 250-85-42, Emergency Diesel Generator Loading. Revision 1 to this LER, documenting that the EDG loading problem was reportable under 10 CFR 21, was issued on June 16, 1986. This LER and its revision document the potential overload scenario and itemized 11 corrective actions. The completion of the corrective actions were reviewed in Inspection Reports 250,251/86-24; 250,251/86-34; and the SE dated December 15, 1986.

(Closed) LER 250-86-03, D Motor Control Center (MCC) Automatic Transfer. On January 18, 1986, during EDG load study reviews, the licensee determined that the D MCC automatic transfer was subject to a single failure. The licensee initially compensated for this deficiency through procedure changes and the operator training program. In July 1986 Plant Change Modification (PCM) 86-41, entitled Modification of MCC D Automatic Transfer, was installed. This modification eliminated the single failure susceptibility by adding relays in a parallel logic circuit.

(Closed) LER 250-86-23, D MCC Automatic Transfer. Subsequent to the installation of PCM 86-41, the licensee determined that, due to an oversight in the design of the PCM, a condition could develop which could result in the D MCC being de-energized. A change was made to the PCM and the corrected modification was verified to be correctly installed in the plant. Post modification testing was completed for PCM 86-41 in late July 1986. The D MCC was observed to perform properly during Engineered Safeguards Testing in July 1986.

(Closed) Deviation 250,251/86-24-04. This deviation was issued because some licensee procedures were not modified to limit EDG loading to 2845 kilowatts as agreed in the CAL dated April 2, 1986. The licensee responded to this deviation on August 13, 1986, in letter L-86-338. Between April and August 1986, numerous procedure reviews were performed by the NRC inspection staff to assure that they properly addressed load control. Satisfactory compliance with the requirements of the CAL were verified prior to the issuance of a June 26, 1986 NRC letter approving dual unit operation once the agreed upon load changes were completed. The required load changes were completed in July 1986. Dual unit operation was initiated in August 1986.

(Closed) Violation 250,251/86-25-02. This violation addressed minor procedural inadequacies relative to the control of valves in the EDG fuel and air lines. Procedure 0-OP-23 was revised in July 1986 to correct the discrepancies.

(Closed) Violation 250,251/86-25-03. This violation was issued because drawing 5610-T-E-4536, Revision 0, sheets 1 and 2 contained minor inaccuracies. The drawing was revised to correct the discrepant items in July 1986.

(Closed) UNR 250,251/86-29-01. This unresolved item documented three areas of NRC concern relative to the EDG overload issue. Each concern has been addressed by the licensee and reviewed by the NRC staff. The addressed concerns were as follows:

Item (a) documented a concern that the Engineered Safeguards Integrated Test, 3/4-OSP-203, did not evaluate EDG loading from a single failure perspective. The procedure was revised and implemented in July 1986. Performance of the calculations to determine EDG loading assuming the failure of a single generator was observed and documented as satisfactory in Inspection Report 250,251/86-34. The licensee plans to perform these calculations during each performance of procedure 3/4-OSP-203. This issue was determined not to constitute a violation of requirements because TS surveillances are not required to be performed while simulating a single failure.

Item (b) documented that an EDG could have become overloaded during a design basis accident. As documented in the December 16, 1986, SE, the overload potential has been alleviated.

Item (c) documented a concern that the EDGs remained susceptible to overload in December 1985 even after the licensee removed some equipment from service. It has been determined that the licensee was not aware of this additional overload potential until February 1986, when comprehensive load studies were completed. Consequently, the December overload potential was inadvertent. Additionally, concerns relative to the adequacy of the implementation of the Justification for Continued Operation (JCO) in December 1985 have been resolved by a similar issue which was addressed in Enforcement Action (EA) 86-20. Violation 250,251/86-26-07 Part C was issued on August 12, 1986, specifying that the requirements of another JCO were not fully implemented. Corrective action for failure to comply with these JCO requirements will be tracked under violation 250,251/86-26-07.

b. Auxiliary Feedwater Problems

On April 19, 1983, plant personnel discovered that all auxiliary feedwater (AFW) capability was disabled while Unit 3 was operating at full power. Unit 4 was in cold shutdown during the time period (April 14-19) that the AFW system was inoperable. A special safety inspection was conducted between April 19-28, 1983, to review the circumstances associated with the event. On August 15, 1983, a Severity Level II violation was issued because the requirements of Technical Specification 3.8.4, which requires two operable AFW pumps and associated flow paths when the reactor is above 350 degrees F., were exceeded. Inspection Report 250,251/83-15 identified two additional concerns which contributed to the loss of the AFW system. In-plant equipment clearance orders were not independently verified subsequent to AFW valve retagging and Nuclear Turbine Operators incorrectly logged as open AFW steam supply valves which were closed.

FPL responded to the violation on September 9, 1983, by letter L-83-481. Six corrective actions were specified. The corrective actions included: revision of the of the Nuclear Turbine Operator's logsheets to clarify AFW flowpath verification; submission of a change to the Technical Specifications to require the performance of monthly safety system flowpath walkdowns; development of an interim safety system walkdown program until the Technical Specification change approval is complete; upgrade equipment control measures for locked valves, keys and equipment labeling; initiate periodic shift meetings to emphasize procedure adherence; and examine ways to upgrade the capability to identify potential problems.

The following four items are closed based on a review of the appropriate corrective actions, as appropriate.

(Closed) Violation 250,251/83-15-01 and IFI 250,251/83-15-02. This violation and its associated followup item documented the operation of Unit 3 at power with the AFW system isolated. The inoperability of the system was caused by hanging clearance tags on incorrect valves. Weaknesses in the independent verification program and in the control of

locked valves contributed to the inadvertent system isolation. The licensee made immediate revisions to applicable procedures to prevent recurrence. Additional changes to procedures have been made as part of the Procedure Upgrade Program. The following procedures have been reviewed by the inspectors and were found to adequate:

ADM-031 Independent Verification, Revision dated July 12, 1985

ADM-205 Administrative Control of Valves, Locks and Switches, Revision dated February 13, 1987

AP-0103.4 In-Plant Equipment Clearance Orders, Revision dated December 30, 1986

Additionally, the inspectors verified that the Technical Specifications were revised to incorporate the requirement to perform monthly walkdowns of safety system flowpaths. This requirement was added to the Technical Specifications in Amendment Numbers 97 and 91 which became effective on October 26, 1983. The requirements of Technical Specification 4.18 are implemented by procedure AP-0103.19, Monthly Verification of Safety Related Systems Flowpaths, Revision dated January 8, 1987. This procedure has been reviewed and was found to be adequate.

(Closed) IFI 250,251/83-15-03. This item documented a concern that procedure AP-0103.4 did not adequately address the requirements for independent verification when a tag was rehung following a temporary lift authorization. The procedure now adequately addresses this area. The inspectors have verified that independent verification is routinely performed during retagging when the clearance involves safety related equipment.

(Closed) IFI 250,251/83-15-04. This item documented a concern that Nuclear Turbine Operators did not accurately annotate their log sheets when verifying AFW system status. Consequently, the logs indicated that the system was properly aligned when actually it was isolated. A contributing factor to this problem was the then recent installation of a second, independent AFW steam train. The Operators were not sufficiently familiar with the location of newly installed valves. Site training programs have corrected this concern. Newly installed equipment is described in Training Briefs that often contain pictures and diagrams of equipment locations. Significant plant changes are summarized and placed on mandatory required reading lists. Additionally, newly installed equipment must be accepted by the Operations Department prior to the equipment being placed in operation. This acceptance is not exercised until all procedures, drawings and instructions and training related to equipment operation, maintenance and repair have been approved and distributed. Procedure AP 0103.2, Responsibilities of Operators and Shift Technicians on Shift and Maintenance of Operating Logs and Records, Revision dated February 13, 1987, has been reviewed and it adequately addresses the importance of accurate log keeping.

c. General Enforcement

(Closed) Violation 251/86-45-03, Failure to Meet the Requirements of TS 3.3.3. On September 26, and October 6, 1986, a Unit 4 steam generator blowdown isolation valve and associated bypass valve failed closed, in the isolated position. These valves are phase A containment isolation valves. Operations personnel, in each event, failed to comply with the requirements of TS 3.3.3, in that, the effected penetration was not properly isolated by removing power to the inoperable valve(s) or closing a manual isolation valve in the penetration. Operations personnel had believed that because the valves failed in the closed position that the penetration was properly isolated. The corrective actions initiated by the licensee included: issuance of Training Brief #185 to clarify the requirements of TS 3.3.3 and operations memorandum PTN-OPS-86-210 was reissued to all onshift licensed operators to reinforce the need to contact the operations supervisor, the operations superintendent and licensing personnel when questions of TS compliance arise. The corrective actions were implemented by January 23, 1987, and should preclude a recurrence of this violation.

(Closed) Violation 250,251/86-39-02, Failure to maintain an effective program for the correction of conditions adverse to quality, two examples; in that, (1) licensee action taken to preclude missing additional TS surveillances was inadequate, and (2) licensee corrective action to implement the requirements of AP 0103.36 was ineffective. In regard to example (1), the licensee has revised AP 0190.16, Scheduling and Surveillance of Periodic Tests and Checks Required by Technical Specifications, to provide a matrix of all TS surveillances. New or revised TS requirements are implemented into the matrix by the FPL commitment tracking system (CTRAC). Procedures 0-OSP-200.1, Schedule of Plant Checks and Surveillances, and 0-OSP-200.2, Plant Startup Surveillances have been written and implemented to centralize scheduling responsibility and to ensure required performance of surveillances prior to a mode change. For example (2), AP 103.36 was revised to change audit and review responsibility to the Operations System Enhancement Coordinator.

(Closed) Violation 250,251/83-09-02, Failure to properly implement procedures, two examples; in that, (1) the TS time limit was not recorded in the Equipment Out of Service (EOOS) Log as required by AP 0103.2 and (2) the area radiation monitoring (ARM) panel horn disable light was not reset as required by ONOP 11208.1. A plant memo was distributed to all Plant Supervisors-Nuclear to require operators to research TS time limits and record them when declaring equipment out of service in the EOOS log. The operators were reminded of the requirement to reset the horn disable light on the ARM panel. Both of these requirements were reviewed with all operators by the training department.

(Closed) URI 250,251/83-24-04, Question of whether an operable emergency exit to the RCA should exist in the auxiliary feedwater pump room vital area. An emergency exit door exists in the auxiliary feedwater pump room

vital area which leads to the Radiation Controlled Area (RCA). The door is a security controlled passage, alarmed and locked closed to individuals attempting to exit the RCA. It is intended for safety of plant personnel in the event that an accident should occur in the AFW pump room, such that, evacuation through the normal exit is not possible. It is clearly marked for use as an emergency exit only and is clearly marked that the individual would be entering the RCA. The door will alarm when opened and security personnel will respond. The door would close and lock, prohibiting re-entry from the RCA. Once inside the RCA the individual could only exit via the RCA control point where he/she would be properly monitored by health physics personnel. The individual would not have to pass through any posted radiation areas to arrive at the RCA control point.

(Closed) Violation 250,251/84-11-02, Failure to complete adequate surveillance testing on Emergency Containment Filter System and the Control Room Ventilation System. Operating Procedure (OP) 4704.3, Emergency Containment Filter System - Performance Test, and OP 10304.1, Control Room Emergency Ventilation Filter System - Performance test, were revised and appropriate testing was completed.

(Closed) URI 250/84-14-02, The absence of procedures covering the operation of vital instrument buses. Off-Normal Operating Procedures for loss of 120V Vital Instrument Panels have been written and implemented. An Operating Procedure for 120V Vital Instrument AC system has been implemented.

(Closed) Violation 250/84-18-07, Failure to accurately establish a procedure for calculating estimated critical conditions (ECC). Operating Procedure 1009.1, Estimated Critical Conditions, was revised and the Shift Technical Advisor is required to perform a backup ECC.

(Closed) Violation 250/84-22-01, 251/84-23-01, Inadequate charging pump procedure due to the fact that the procedure had no operability criteria. Charging pump and boric acid transfer pump operability criteria was developed and the associated procedures were revised to include operability criteria.

(Closed) Violation 250/84-22-02, 251/84-23-02, Failure of Maintenance Procedure (MP) 4107.7, High Head SIS Pump Disassembly, Replacement of Rotating Element and Reassembly, to meet requirements of TS 6.8.1. The procedure has been revised.

(Closed) Violation 250/84-23-01, 251/84-24-01, Inadequate 10 CFR 50.59 evaluation, due to limiting the review against FSAR Chapter 14 Accident Analysis only. All affected procedures have been revised to require a safety evaluation using the entire FSAR.

(Closed) Violation 250/84-23-02, 251/84-24-02, The pump surveillance tests for the Residual Heat Removal (RHR) and High Head Safety Injection (HHSI) pumps did not verify by the instruments and visual observations that the

pumps were properly functioning. Procedures 3/4-OSP-068.2, Containment Spray Pump Inservice test and OP 4104.1, High Head Safety Injection System Periodic Test, have been revised to include verification that the seals and seal water system meet design functions.

(Closed) URI 250/84-14-01, Evaluation of Performance Enhancement Program, the program does not appear to have established escalated priorities for procedures and drawings which are used frequently, for example:

(1) Unlabeled valves exist in Safety Injection drawings;
(2) EDG Operating Procedure does not have sign off or independent verification.
(3) There is no procedure which addresses the loss of electrical distribution to control room instrumentation.

In an inter-office correspondence, dated October 22, 1985, the licensee states they have completed phase I of the valve labeling effort and commenced phase II. This is a continuing effort which will use information adopted from the latest drawings and procedures. The EDG Operating Procedures have been revised and O-ADM-031, Independent Verification (IV), procedure addresses IV requirements. Procedures for loss of 120V Vital Instrumentation have been implemented.

(Closed) Violation 251/82-39-02, ONOP 0208.1, Post Reactor Trip Review. This procedure has been cancelled. AP 0103.16, Duties and Responsibilities of the Shift Technical Advisor, adequately addresses post reactor trip review with Appendix B, Post Trip Review.

(Closed) Violation 250/84-34-01, 251/84-35-01, Failure to establish procedures identifying the proper method of draining and filling the CCW heat exchangers, plugging leaking heat exchanger tubes, testing for tube leakage, and hydro-blast cleaning. Procedure 3/4-PMM-030.1, Component Cooling Water Heat Exchanger Cleaning, has been implemented addressing the above concerns.

(Closed) Violation 250/84-34-02, 251/84-35-02, Failure to implement a temporary procedure change to MP-3207.2, Residual Heat Removal Plugs Disassembly, Repair, Seal Replacement and Assembly. The Plant Management issued a directive stating the requirement of on-the-spot changes to procedures. AP 109.3, On the Spot Changes to Procedure (OTSC), implements OTSC requirements.

(Closed) Violation 250/84-34-03, 251/84-35-02, Failure to implement written procedures during repair of the 4B residual heat removal (RHR) pump. Procedure MP 3207.2, was revised to reference Procedure MP 0707.33, Snubber Removal and Replacement, to ensure safety related snubbers are removed properly. Maintenance foremen and supervisors were counseled on the requirements of Procedure AP 0109.10, Cleaning of Nuclear Safety Related Systems and Components.

(Closed) Violation 250/84-28-01, 251/84-29-01, Failure to develop accurate ECC and 1/m plot procedure. OP 1009.1, Estimated Critical Conditions, and 3/4-GOP-301, Hot Standby to Power Operation, have been revised to improve startup procedure guidance.

(Closed) Violation 250/84-28-02, 251/84-29-03, Failure to retain an archival copy of the Moderator Temperature Coefficient (MTC) curve. The licensee implemented procedure AP 0103.44, Plant Curve Book, which delineates the administrative controls and requirements on the Plant Curve Book.

(Closed) Violation 251/84-29-02, Failure of the licensee to identify excessive time delay between relay drop out and trip breaker opening as required by Appendix A of ONOP-0208.1, Shutdown Resulting From Reactor Trip on Turbine Trip. AP-0103.16, has been implemented. Appendix B, of this procedure, Post Trip Review, includes a requirement to subtract relay dropout time from reactor trip breaker opening time.

(Closed) Violation 250/84-23-04, 251/84-24-04, Failure to turnover the Pressurizer Heater Circuit Modification, PC/M 81-29 and 81-30 in accordance with AP 0103.17, Systems/Equipment Acceptance/Turnover to Plant Staff. Corrective action included: Drawing 5610-T-L1, sheet 23 has been revised; the Pressurizer Keylock Switches were labeled; and AP 0190.15, Plant Changes and Modifications (PC/M), was revised. These procedure revisions require the implementing department to be responsible for scheduling and incorporating required implementation comments and for transmitting drawing update information to site drawing update group.

(Closed) Violation 250,251/85-08-01, Inadequate procedures for Containment Spray Pumps - Periodic Test, Schedule of Periodic Tests, Checks, and Operating Evolutions, and Monthly Verification of Safety Related Equipment. Procedures 3/4-OSP-068.3, Containment Spray System Monthly Flowpath Verification, OP-0204.2, Periodic Tests, Checks, and Operating Evolutions, and AP 0103.19, Monthly Verification of Safety Related Systems Flowpaths, were revised. Additionally, Training brief number 45, "480 volt load center breakers" was issued to licensed and non-licensed operators.

5. Followup on URIs, IFIs, IE Information Notices (IENs), IE Bulletins (IEBs) (information only), IE Circular (IEC), and NRC Requests (92701)

A review was conducted of the following items to assure that adequate applicability reviews were performed, appropriate distribution was made, and if required, adequate and timely corrective actions were taken or planned.

(Closed) IEC 250,251/79-CI-22, Stroke Testing of Power Operated Relief Valves (PORVs). The pressurizer PORVs are stroke tested per OP 0209.1, Valve Exercising Procedure. Appendix B to AP 0209.1 requires that during

unit cold shutdown the PORVs are exercised to ensure they open within 15 seconds and that the pressurizer PORV block valves are stroke tested to ensure that they close within 60 seconds. Appendix P to AP 0209.1 requires that the pressurizer PORVs and PORV block valves be stroke tested to the same criteria as a valve post maintenance test.

(Closed) IEC 250,251/80-CI-07, Problems With High Pressure Coolant Injection (HPCI) Turbine Oil System. The recommended actions of IEC 80-07 were written for BWR licensees and construction permit holders and are not applicable to Plant Turkey Point (PTP).

(Closed) IEC 250,251/80-CI-09, Problems With Internal Communications Systems. IEC 80-09 recommends that licensees take actions to determine the source of power for plant internal communications and if necessary upgrade the system to ensure operability during a loss of offsite power event (LOSP). It was also recommended that licensees identify any plant electronic equipment that may be adversely effected by portable radio transmissions and instruct employees on the potential effects of operating portable radios in these areas. PTP internal communications, paging, and evacuation alarm system (Gai-tronics) is powered from a vital bus in the D MCC (motor control center). The system has the ability to transfer control power between Unit 3 or Unit 4 and, ultimately, if a LOSP event occurred the system would be powered by the emergency diesel generators. Areas in which operation of a portable radio could effect electronic equipment have been previously identified, clearly caution labeled and plant personnel were instructed as to the use of radios in these areas.

(Closed) IEC 250,251/80-CI-10, Failure To Maintain Environmental Qualification Of Equipment. IEC 80-10 recommends that licensees take action to ensure that: adequate administrative controls exist to ensure that equipment which is environmentally qualified is identified prior to maintenance; maintenance procedures are such to ensure that environmental qualification of equipment is not degraded as a result of maintenance activities; and maintenance personnel are adequately trained on environmental qualification requirements. PTP utilizes procedures to provide guidelines and administrative controls to ensure that all equipment requiring environmental qualification remains qualified, in accordance with the requirements of 10 CFR 50.49, through maintenance and surveillance activities. Procedures 0-ADM-703, 10 CFR 50.49 Environmental Qualifications, and 0-ADM-704, Environmental Qualification Index, identify all environmentally qualified equipment, give instructions to ensure that qualification is not degraded during maintenance or surveillance testing.

(Closed) IEC 250,251/80-CI-11, Emergency Diesel Generator (EDG) Lube Oil Cooler Failures. IEC 80-11 recommended that licensees take action to ensure that the corrosion inhibitors used in the jacket water of the EDGs is compatable with the solder material used to seal the tubes to tube sheets in the lube oil coolers per the manufacturers recommendations. The EDGs at PTP, manufactured by the Electro-Motive Division (EMD) of General Motors, presently use chromate as the corrosion inhibitor in the jacket water, per the manufacturer's recommendation. No negative results have

been experienced with the use of chromate, but due to environmental concerns, Nalco 2000, a borate - nitrite type inhibitor, is planned for future use. The lube oil coolers will be replaced to maintain compatability with the corrosion inhibitor. Nalco 2000 is also an EMD recommended corrosion inhibitor. The 3B EDG lube oil cooler replacement will take place during the Spring 1987 Unit 3 refueling outage.

(Closed) IEC 250,251/80-CI-15, Loss of Reactor Coolant Pump (RCP) Cooling and Natural Circulation Cooldown. IEC 80-15 recommended several actions be taken into consideration by licensees to mitigate the consequences of a natural circulation cooldown events. Plant Turkey Point has procedures in place which provide actions to perform a natural circulation cooldown with or without a steam void in the reactor vessel, and with or without the reactor vessel level monitoring system (RVLMS) available. Emergency Operating Procedure 3/4-EOP-ES-0.2, Natural Circulation Cooldown, 3/4-EOP-ES-0.3 Natural Circulation Cooldown With Steam Void In Vessel With RVLMS (QSPDS), and 3/4-EOP-ES-0.4 Natural Circulation Cooldown With Steam Void In Vessel Without RVLMS (QSPDS), provide actions to ensure RCP seal cooling and minimize or preclude the conditions described in the circular.

(Closed) IEC 250,251/81-CI-14, Main Steam Isolation Valve Failures To Close. The licensee reviewed and evaluated the MSIV system with regard to IEC 81-14 and concluded that the failure modes described in the circular were not applicable to PTP. The review however revealed a 10 CFR part 21 deficiency concerning the MSIV system, in that, under low flow conditions and loss of instrument air pressure, the accumulator air volume may not be sufficient to close the MSIVs. LER 250/85-20 was generated and included corrective actions to upgrade the system to meet the FSAR closure criteria without steam flow assistance. The resolution of the discrepant MSIV condition will be tracked via the open LER.

(Closed) IEC 250,251/81-CI-12, Inadequate Periodic Test Procedure Of PWR Protection System. Inspection and Enforcement Circular (IEC) 81-12 recommends licensees verify or develop procedures which test each reactor trip breaker independently for each trip function, including the shunt and undervoltage coils. PTP Operational surveillance procedure 3/4-OSP-049.1, Reactor Protection System Logic Test, verifies the operability of the reactor trip logic, including the shunt and undervoltage coils. Maintenance Procedure 0707.12, Reactor Trip and Reactor Trip Bypass Breakers - Manual Trip Test, provides instructions for physically testing the manual reactor trip function to ensure that both the shunt and undervoltage coils in all reactor trip and reactor trip bypass breakers are operational. Maintenance Procedure 0707.10, Reactor Trip and Reactor Trip Bypass Breakers - Inspection and Maintenance, provides instruction for proper maintenance inspection, cleaning and lubrication of the reactor trip and reactor trip bypass breakers to prevent sluggish and erratic operation.

(Closed) IEC 79-CI-18, Proper Installation of Target Rock Safety-Relief Valves. Turkey Point has no Target Rock Safety-Relief Valves installed.

(Closed) IEC 79-CI-20, Failure of GTE Sylvania Relay, Type PM Bulletin 7305, Catalog 5U12-11-AC with a 120V AC coil. Turkey Point has no GTE Sylvania Relays Type PM Bulletin 7305 on site.

(Closed) IEC 79-CI-25, Stock Arrestor Strut Assembly Interference. In a FPL inter-office correspondence, dated January 10, 1980 on IE Circular 79-25, the licensee states, we have replaced these snubbers with Pacific Scientific Company mechanical snubbers, but the aforementioned "Strut Assembly and Adaptor" were not used.

(Closed) IEC 77-CI-15, Degradation of Fuel Oil Flow to the Emergency Diesel Generator. The licensee has included flow testing on the fuel oil system when performing the diesel generator operability test. Additionally, the fuel oil system is under a 18 month preventive maintenance program. The fuel oil cleanliness is verified on a quarterly basis and checked for viscosity, water and sediment per a standard of the American Society for Testing and Material (ASTM), D 975-78.

Site Engineering has conducted a diesel generator fuel oil evaluation under a request for engineering assistance (REA) 86-53, dated November 21, 1986. This evaluation report reviewed the sites testing requirements, purchasing requirements, and on-site handling requirements against NRC Regulatory Guide 1.137, "Fuel Oil Systems for Standby Diesel Generators". The report made a number of recommendations that the plant is evaluating.

The recommended action of REA 86-53 and the circulars information concerning fuel oil cleanliness will be tracked under IE Information Notice 87-04: Diesel Generator Fails Test Because of Degraded Fuel.

(Closed) IFI 250,251/78-27-03, Boric Acid Leakage on Safety-Related Cable Trays. In inspection report 250,251/79-08, it was noted that boric acid leakage was abated by diverting the leakage away from the cable trays and Plant Change Modification (PCM) 77-011 was initiated to repair the floor drain. The work was completed September 4, 1985.

(Closed) IFI 250/84-18-02, Proper recognition of Containment integrity valves. This item is administratively closed and the completion of corrective action will be tracked under LER 251/84-09. The corrective action of writing a procedure in listing all containment boundary valves for both units is still being pursued by the licensee.

(Closed) IFI 250/84-18-04, What is the allowable range for containment temperature. In an inter-office correspondence from Power Plant Engineering to Plant Manager-Nuclear, dated October 9, 1984, an Evaluation of Unit 3 Operation with 3C Normal Containment Cooler Out-of-Service, states that operation without the 3C cooler is within the normal configuration as long as containment temperature does not reach 120°F (this value is addressed in the FSAR).

(Closed) IFI 250/84-22-06, Update Administrative Procedure for the Corrective Action Tracking System (CATS). O-ADM-913, Corrective Action

for Conditions Adverse or Quality, was implemented to define a program for safety related or Quality related items considered adverse to quality, and the requirements, responsibilities, and interfaces necessary to identify, track, and correct.

(Closed) IFI 250/84-22-07, Review the Auxiliary Feedwater Pump Task Force report to insure responsibilities and due dates are assigned. All actions have been assigned or completed and the status of completion of the report is being tracked. Additionally, the Auxiliary Feedwater System is in the Phase II Select System assessment program.

(Closed) IFI 250/84-22-08, 251/84-23-08, Failure to implement Administrative Procedure (AP) 0190.10, Cleaning of Nuclear Safety Related Systems and Components. Corrective actions have been completed. Procedure MP 4107.7 was revised to include steps to protect against foreign material intrusion.

(Closed) IFI 250/84-22-09, 251/84-23-09, Failure of individual worker to clean their work area at the end of a shift. The Plant Manager-Nuclear had instructed each Department Head to review AP 0103.11, Housekeeping, for item of responsibility.

(Closed) IFI 250/84-23-10, 251/84-24-10, Failure to verify Refueling Water Storage Tank (RWST) calculated level with indicated level. PC/M 83-33 was completed to add an additional RWST level indication. Additionally, procedure OP 0204.2, Periodic Tests, Checks and Operating Evolutions, was revised to ensure the two indications are within set limits.

(Closed) IFI 251/81-08-02, Failure of the 4A 4160 Volt Bus to transfer. The license conducted an investigation into the 4A 4160V Bus failure to transfer problem as documented in inter-office correspondence, dated July 31, 1981, and found no problems in that all circuits were found operational.

(Closed) IFI 251/81-08-01, Review feasibility of replacing the snubber end pieces with a stronger type. The snubber was repaired under PWO 2675 using PC/M 81-46.

(Closed) IFI 250/84-23-08, 251/84-24-08, Failure to Comply with AP 0190.9, Control of Measuring and Test Equipment. This was an example of violation (250/84-23-04, 251/84-24-04) which was partially denied and the NRC agreed. The storage of uncalibrated equipment in the same location as calibrated equipment became URI 250/84-23-18, 251/84-24-18.

(Closed) URI 250/84-23-18, 251/84-24-18, Storage of uncalibrated equipment in the same location as calibrated equipment. AP 0190.9 was revised to require that uncalibrated and calibrated equipment be stored separate.

(Closed) IFI 250/84-23-12, 251/84-24-12, Uncontrolled tables in the curve/tank book. Procedure AP 0103.44, Plant Curve Book (PCB), was implemented to delineate the administrative controls and requirements on

the plant curve book. The Plant Nuclear Safety Committee reviews all changes to the PCB prior to their incorporation.

6. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations. No unresolved items were identified during this inspection period.

7. Onsite Followup of Written Reports Of Nonroutine Events (92700)

The Licensee Event Report (LER) discussed below was reviewed and closed. 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 that the licensee had reviewed the 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.

(Closed) LER 251/86-20, TS - Out of Service Steam Generator Blowdown Valve Not Isolated Within Required Time. There were two recent occurrences of failed phase A containment isolation valves in which operations personnel failed to properly isolate the containment penetration per TS 3.3.3. Each event involved a Unit 4 steam generator blowdown valve and associated bypass valve. Operations personnel were unaware that although the valves failed closed in the isolated position, TS 3.3.3 required that the power to the affected valves be removed or a manual containment isolation valve in the affected penetration be closed within four (4) hours. Violation 251/86-45-03 was issued as a result of the TS misinterpretation. The LER corrective actions were tracked via the licensee response (paragraph 4.c) to the violation and found to be adequate.

8. Performance Enhancement Program (PEP) Summary

On March 2, 1987, Florida Power and Light held a dedication ceremony for the Turkey Point Plant Nuclear Training Center. Among those in attendance were Lando W. Zech, NRC Chairman, J. Nelson Grace, Region II Administrator, and key members of FPL corporate management. During the ceremony, INPO Certificates were awarded to select members of the Turkey Point Operations Staff. Additionally, four NRC operator licenses (three Senior Reactor Operator and one Reactor Operator) were presented.

9. Monthly and Annual Surveillance Observation (61726/61700)

The inspectors observed TS required surveillance testing and verified: that the test procedure conformed to the requirements of the TS; that testing was performed in accordance with adequate procedures; that test instrumentation was calibrated; that limiting conditions for operation (LCO) were met; that test results met acceptance criteria requirements and

were reviewed by personnel other than the individual directing the test; that deficiencies were identified, as appropriate, and were properly reviewed and resolved by management personnel; and that system restoration was adequate. For completed tests, the inspectors verified that testing frequencies were met and tests were performed by qualified individuals.

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

OP 14004.3 Tave and Delta T Protection Channels - Periodic Test Unit 4

Control Room Ventilation DP-312A Transfer Switch Inspection

Plant Maintenance Instruction 63001, dated February 2, 1987, provides guidance for the inspection and operation of DP-312A transfer switch. This switch determines the source of power (MCC-3A or MCC-D) for the temperature control circuitry of the control room ventilation system (CRVS). Failure of this switch can cause loss of all CRVS air handling units and compressors affecting both the atmospheric cleanup and the air conditioning portions of the CRVS. Justification for Continued Operation (JCO JPE-L-86-113, Rev. 1) requires, in part, that as a result of the identification of potential single failures in the CRVS, and until permanent modifications are made, operability of the transfer switch will be verified on a weekly basis.

No violations or deviations were identified within the areas inspected.

10. Maintenance Observations (62703/62700)

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

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

The following maintenance activities were observed and/or reviewed:

C Auxiliary Feedwater Pump (AFW) governor oil change; and,
4C AFW steam supply line steam trap (ST-4-1413) repair.

11. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs, conducted discussions with control room operators, observed shift turnovers and confirmed operability of instrumentation. The inspectors verified the operability of selected emergency systems, verified that maintenance work orders had been submitted as required and that followup and prioritization of work was accomplished. The inspectors reviewed tagout records, verified compliance with TS LCOs and verified the return to service of affected components.

By observation and direct interviews, verification was made that the physical security plan was being implemented.

Plant housekeeping/cleanliness conditions and implementation of radiological controls were observed.

Tours of the intake structure and diesel, auxiliary, control and turbine buildings were conducted to observe plant equipment conditions including potential fire hazards, fluid leaks and excessive vibrations.

The inspectors walked down accessible portions of the following safety related systems to verify operability and proper valve/switch alignment:

A and B Emergency Diesel Generators
Auxiliary Feedwater
Control Room Vertical Panels and Safeguards Racks
Spent Fuel Pool (Units 3 and 4)
Intake Cooling Water Structure

On December 9, 1986, Surry Unit 2 feedwater suction line failed catastrophically as detailed in IE Information Notice 86-106 and IEN 86-106, Supplement 1. In addition to the feedwater line failure, inspection revealed that the A feed pump discharge check valve had failed. Although the check valve failure did not contribute to the suction line failure it may have contributed to the volume of water/steam released. As a result of this event and previous check valve failures at other nuclear plants, inquiries have been made regarding licensee action (either existing or planned) to resolve safety concerns involving check valves at operating nuclear power plants. The following is a synopsis of the industry's plans to take a leadership role in addressing check valve concerns and action to be taken by Turkey Point as a result.

In a letter to Del Butterfield, Westinghouse Owner's Group dated February 24, 1986, Victor Stello, NRC Executive Director for Operations, expressed concern regarding the design, testing and maintenance of safety

related check valves and that the November 21, 1985, loss of power and water hammer event at San Onofre Unit 1 may have significant generic implications. He urged all NSSS Owners Groups to take prompt action to preclude similar challenges to plant safety systems.

The Owners Groups, in conjunction with NUMARC and INPO, proposed that the industry engage in a self managing effort to address the issues raised by the San Onofre event and, as well, check valve malfunctions identified at other operating nuclear plants around the country.

In October, 1986, INPO held a workshop in Atlanta to address these check valve concerns. Attending the workshop were representatives from utilities, A & E firms, NSSS vendors, valve companies, and the NRC. As a result of this meeting, an approach has been taken which includes the issuance of an INPO Significant Operating Experience Report (SOER 86-3), the development of a check valve application guide, and an implementation schedule agreed upon by the NRC and the NUMARC Owners Group.

A FPL Check Valve Task Team has been established to develop a company approach to SOER 86-3 and to develop a project schedule. The team is developing a matrix for listing valve data, maintenance history, service condition, code case values, present test methods, required actions, and recommended preventative maintenance. This matrix system will be developed first on the Main Steam System and is to be used as a pilot for the remaining systems as recommended in the SOER. FPL intends to complete the matrix for all selected systems by January 1, 1988, and to complete all required design changes identified by July 1989.

On February 5, 1987, the inspectors observed a flaw on the disk of Intake Cooling Water (ICW) check valve Serial Number (S/N) B816-F. This valve had recently been purchased along with six other ICW check valves. Five of the check valves had already been installed in the Unit 3 and 4 ICW systems. The valve with S/N B816-F was to be installed adjacent to the 3B ICW pump as a replacement for valve 3-321. The linear indication on the disk was approximately 1/2 inch long, was located on the outer edge of a support webb, and was clearly visible, having the appearance of a "hairline" crack. The plant QC organization was informed of the indication. Plant QC and Backfit Construction QC inspectors were not sure whether the flaw was of a size and type which was acceptable. A Discrepant Field Condition report (DFC 018-87 dated February 5, 1987) was issued documenting that the "crack" was not specifically mentioned in QA surveillance reports performed at the vendor's warehouse. Neither was it mentioned as a discrepancy on plant Receipt Inspection Report (RIR) 87-3009, which had been performed on January 15, 1987.

A QC evaluation of the DFC recommended, on February 9, 1987, that the Engineering department evaluate the discrepancy and Non-Conformance Report (NCR) 66-87 was issued for that purpose.

On February 11, 1987, the engineering staff members completed an Initial Engineering Assessment of Operability relative to the NCR by completing an

Engineering Item Review Form as required by Engineering Procedure 2.7, Revision dated December 4, 1986. The form requires the completion of an Engineering Evaluation, the purpose of which, as defined by EP 2.7 Section 5.2.4, is to "...provide a clear and concise evaluation of the effect of an item on its system's performance, with specific conclusions regarding the systems operability and safety design basis. Reference should be made to appropriate sections in the FSAR (including Chapter 14 accident analyses), controlled vendor information, the Project Q-list, and original analyses by Bechtel and Westinghouse to define the safety function of the item and the significance of the item."

The Engineering Evaluation stated that all seven ICW check valves had been visually inspected at the vendor warehouse by both vendor and licensee QC personnel. Inspection reports did not document any unacceptable conditions. A member of the Engineering Department contacted the vendor and described the indication over the telephone. The Engineering Evaluation documented that the vendor stated that the defect was acceptable and the valve could be used "as is". For these reasons the engineering staff concluded that the flaw was not an operability concern.

On February 23, 1987, an Engineering Evaluation of the issue was completed as required when processing a NCR. This evaluation reiterated the statements made in the Initial Engineering Item Review. The evaluation repeated the vendor's statement that the indication was acceptable per Manufacturer's Standardization Society (MSS) SP-55, which was the quality standard which the Purchase Order (01055-71798P) specified for visual inspection of the valves.

The inspectors reviewed the requirements of MSS-SP-55, 1985 Edition, entitled Quality Standard for Steel Castings for Valves, Flanges and Fittings and Other Piping Components (visual method). The standard specified, on pages 1 and 4 that visible surface cracks and/or hot tears are not acceptable indications. Additionally, the standard addressed twelve general types of irregularities which may or may not be acceptable depending upon magnitude.

Since DFC 18-87 described the flaw as a crack, the inspectors questioned engineering personnel as to why the condition was dispositioned as acceptable. The licensee reiterated that the flaw was acceptable for two reasons: 1) QC inspections performed during valve fabrication and testing did not mention the flaw; and 2) the vendor stated that the flaw was acceptable during a telephone call.

Disposition based on these criteria did not appear to be adequate. In discussing the evaluation with members of the Engineering Department it was determined that:

(1) The vendor did not recall seeing the flaw prior to shipping the valve. The vendor was not supplied with specific information about the flaw, such exact length or depth. The vendor evaluated the flaw without visually inspecting it either directly or by photograph or

drawing. The vendor did not identify which of the twelve types of irregularities addressed in the standard applied to the flaw. Consequently, no judgement was made that the flaw was of a lesser magnitude than allowed by the pictorial representations contained in the standard. The vendor's evaluation was strictly verbal and was not attributed to an individual of known qualification. No request had been made for the vendor to provide a written assessment of the flaw. Consequently, objective evidence of acceptability was minimal.

(2) It was not possible to determine whether the inspectors at the vendor warehouse noticed the flaw. Consequently, absence of information in the inspection reports did not prove that the flaw was acceptable. It was determined that on-site RIR 87-3009 was not required to be performed on all seven valves. A sampling of two valves was allowed by procedure and the receipt inspection report did not document which two valves were inspected. Consequently, the absence of information in the receipt inspection did not prove that the flaw had been previously evaluated as acceptable. Finally, several QA, QC and Engineering personnel who had seen the flaw and compared it to the standard were unable to categorize it because they were not trained in the visual inspection of castings.

(3) The engineering department had not categorized the flaw with respect to MSS-SP-55 and therefore could not explain why the vendor was correct in asserting that the flaw was acceptable.

On March 6, 1987, the inspectors expressed a concern that the evaluation performed under NCR 66-87 did not adequately explain why the flaw was acceptable. The licensee was asked specify why the flaw was acceptable in terms of specific criteria described in MSS-SP-55. On March 9, 1987, a Level III Visual Inspector examined the flaw and determined that it was categorized as a type VII, which includes wrinkles, laps, wares, folds, and coldshuts. These are surface irregularities caused by incomplete fusing or by folding of molten metal surfaces. The flaw was determined to be a coldshut of less magnitude than the maximum allowable coldshut in picture (e) on page 13 of the standard. A written report to this effect was made part of the disposition of the NCR. This provided objective evidence of acceptability by a person who had specifically studied the flaw and who had a background as a Visual Inspector. Between February 6 and March 9, the valve remained under QC hold so that it would not be installed in the plant.

During the evaluation of the flaw in the ICW check valve S/N B816-F, A QC inspector noticed that licensee warehouse personnel had tagged the valve as S/N B816G. This discrepancy prompted a review of the six ICW check valves which had recently been installed in the plant. It was determined that two of the valves had the identical S/N B816C. Additionally, no valve had S/N B816B. This conflicted with the quality documentation supplied by the vendor for these safety related valves. The vendor listed the valves he manufactured and tested as S/N B816 A through G. This was verified by surveillance inspections performed by a licensee

representative during the manufacture and testing of the valves prior to shipping. The discrepancy was not identified during receipt inspection on report RIR-87-3009 because the inspection only reviewed a sampling of the seven valve shipment. The problem was not discovered until after six of the seven valves were installed in the Unit 3 and 4 ICW systems. One valve labeled S/N B816C was installed at the discharge of the Unit 3C ICW pump and the other at the discharge of the Unit 4C ICW pump.

These valves were categorized as Commercial Grade Quality Level II. By procedure the vendor was required to demonstrate traceability of quality parts and materials by Material Certificate of Compliance for shaft and bolting and Mill Test Reports for castings. The licensee surveillance performed at the vendor warehouse documented that manufacturing sources of materials existed for valves B816 A through G. Additionally, it specified that the valves had been marked with vendor's name, S/N, and heat numbers. No quality records existed for a second valve with S/N B816C. Appropriate quality documentation existed for valve B816B but no valve existed with that serial number.

A concern existed that one of the two valves with duplicate serial numbers was not known to be of suitable quality for use in the safety related ICW system. This concern constituted a second issue addressed in DFC 18-87 and NCR 66-87. The Engineering Evaluation for this concern stated that the vendor mistakenly stamped two of the valves with the same serial number and the incorrect stamping did not render either of the valves unfit for use in the system.

This evaluation constituted a concern because it did not evaluate the effect of using a valve of unknown quality in a safety related system and it placed no time limitation on the use of the valve. The licensee engineers felt that one of the valves was actually valve S/N B816B. This was a logical assumption that was not known to be a fact. Additionally, the engineers felt that only seven valves existed because they were made under a special purchase order for the licensee. However, discussions revealed that this had not been established as fact.

On February 26, 1987, the vendor sent the licensee the body heat numbers associated with each S/N. It was determined that these numbers were stamped inside the valve bodies and could be seen without removing the valve from the system. The Technical Specifications allow a 24 hour Limiting Condition for Operation (LCO) during which one train of ICW can be out of service. Valve removal, heat number and serial number verification and valve reinstallation could be performed in the allowable timeframe. The licensee made no attempt to reestablish the quality traceability for the valve by removal and inspection.

On February 9, 1987 the licensee determined that a valve was installed in

in a safety related system which could not be shown to meet procurement requirements because it was stamped with an erroneous, duplicate serial number. On March 10, the inspectors discussed the requirements of 10 CFR 50, Appendix B, Criterion VII, with the licensee. On March 11 valve 4-331, one of the valves with duplicate serial numbers, was removed from the system under the 24 hours LCO. Body heat numbers were verified and it was determined that this valve was the valve which should have been S/N B816B. This effort established that the valve had quality documentation as required by the purchase order. The valve was reinstalled and satisfactorily tested within the allowable timeframe.

NRC management is concerned that the licensee does not always perform adequate engineering evaluations of discrepant conditions. This concern is warranted based on the above, plus enforcement history of the recent past. The following summary documents recent safety evaluation concerns which have been identified by NRC inspectors.

Enforcement Action (EA) 86-20, dated August 12, 1986, documented in Item II, three instances in which adequate safety evaluations were not performed. Item VI of EA 86-20 documented an instance when a corrective action requirement of an NCR was not implemented and no documented basis was generated to justify the change in the approved corrective action. Additionally, Item VI of EA 86-20 documented two instances in which safety evaluations were not performed in a timely manner and one instance in which the safety significance of an identified deficiency was not reviewed in a timely manner.

Subsequent to the issuance of EA 86-20 additional, though less safety significant, problems have been identified in the area of safety evaluations. Inspection Report (IR) 250,251/86-45 documented two instances in which Engineering Department staff members failed to evaluate the safety significance of discrepant conditions which were identified in NCRs. For an extended period of time, no analysis was performed regarding the operability of the affected systems. IR 250,251/86-07 documented a discrepant valve condition for which no analysis or empirical inspection was performed to determine whether the discrepancy increased the potential for valve failure.

The previously identified items of EA 86-20, IR 86-45 and IR 87-06, together with those identified in this report, indicate that additional management attention is warranted in the area of engineering evaluation improvement. The licensee should ensure that evaluations are timely, in-depth, and definitive assumptions used in the evaluations should be well documented and justified as to their reasonableness. For discrepancies found to be acceptable, more emphasis should be placed on documenting why that conclusion is warranted.

NRC managment will continue to evaluate licensee progress in this area through the review of discrepant conditions and the licensee's written assessments of their consequences.

No violations or deviations were identified in the areas inspected.

12. Engineered Safety Features Walkdown (71710)

The inspectors verified operability of the Unit 3 and Unit 4 Spent Fuel Pool (SFP) areas by performing a complete walkdown of all accessible equipment. The following criteria were used, as appropriate, during the walkdown:

a. System lineup procedures matched plant drawings and the as-built configuration.

b. Equipment conditions were satisfactory and items that might degrade performance were identified and evaluated (hangers and supports were operable, housekeeping was adequate, etc.).

c. Instrumentation was properly valved in and functioning and that calibration dates were not exceeded.

d. Valves were in proper position, breaker alignment was correct, power was available, and valves were locked/lockwired as required.

e. Local and remote position indication was compared and remote instrumentation was functional.

f. Breakers and instrumentation cabinets were inspected to verify that they were free of damage and interference.

The inspectors noted the following Unit 3 concerns to licensee management:

a. The A and the B SFP cooling pumps and the emergency cooling water pump were out of service. It was subsequently determined that this lineup was required for a modification to the SFP cooling loop. This modification (PCM 86-207) installs flow measurement devices which allows conformance with ASME Code Inservice test requirements. As stated in a letter from L. S. Rubenstein, NRR, to C. O. Woody, FPL, dated September 18, 1986, these modifications must be made prior to the beginning of the Unit 3 Cycle 11 and Unit 4 Cycle 12 refueling outages.

b. A U-bolt on the cooling pump discharge header was loose.

c. The B cooling pump casing vent valve had a significant leak resulting in accumulation of boric acid crystals.

The inspectors noted the following Unit 4 concerns to licensee management:

a. The emergency SFP cooling pump had a significant shaft leak resulting in the accumulation of water and boric acid crystals on the floor. Additionally, the pump skid was badly corroded.

b. The power supply for the emergency pump was laying in the water noted above.

c. Drawing 5610-T-E-4515 sheet 1 of 3 was in error in that, it references the emergency SFP cooling water pump as Unit 3 equipment only when the Unit 4 cooling system also has an emergency pump.

General housekeeping of both units SFP areas was fair. Tools, flashlights, trash, dirt, water, and boric acid were observed on the floor of both SFP heat exchanger rooms.

13. Plant Events (93702)

The following plant events were reviewed to determine facility status and the need for further followup action. Plant parameters were evaluated during transient response. The significance of the event was evaluated along with the performance of the appropriate safety systems and the actions taken by the licensee. The inspectors verified that required notifications were made to the NRC. Evaluations were performed relative to the need for additional NRC response to the event. Additionally, the following issues were examined, as appropriate: details regarding the cause of the event; event chronology; safety system performance; licensee compliance with approved procedures; radiological consequences, if any; and proposed corrective actions. The licensee plans to issue LERs on each event within 30 days following the date of occurrence.

On February 11, 1987, while at 96% reactor power, Unit 3 Process Radiation Monitoring System (PRMS) Channels R-11 (containment particulate monitor), R-12 (containment gaseous monitor), R-15 (steam jet air ejector monitor) and R-19 (steam generator blowdown radiation monitor) actuated. The actuation of R-11 (R-12 was out of service for maintenance troubleshooting) resulted in containment ventilation and control room ventilation isolation. The cause of the actuation was attributed to maintenance troubleshooting of R-20. After determining that the actuation was spurious, all affected PRMS channels were reset.

On February 11, 1987, the Emergency Notification System (ENS) telephone was discovered to be inoperable. During the time that the ENS telephone was out of service the Southern Bell telephone was verified to be operable.

On February 12, 1987, while at 100% reactor power, Unit 4 PRMS Channel R-11, Containment Particulate Monitor, actuated resulting in containment ventilation and control room ventilation isolation. The cause of the actuation was attributed to Channel R-11 instrument setpoint drift. The required setpoint is 110,000 cpm and the actual setpoint was determined to be 90,000 cpm. In addition, containment atmosphere samples verified that in the four hours previous to the R-11 actuation airborn contamination levels were less than 80,000 cpm.

On February 15, 1987, Unit 3 tripped from approximately 7% reactor power due to low auto stop oil pressure. While performing maintenance/troubleshooting of the turbine governor impeller oil control system the pressure adjusting screw was inadvertently backed fully out of

position. This resulted in increased steam flow (first stage pressure greater than 10%) and loss of auto stop oil. The turbine trip/reactor trip occurred when auto stop oil pressure decreased to less than 45 psig. All automatic protection and control systems were verified to have performed their intended functions, the oil spill was cleaned up and the unit was returned to service on February 16.

On February 20, 1987, an unescorted visitor was discovered in the control room. Control room personnel assumed escort responsibility for the visitor and plant security was immediately notified of the event. Investigation revealed that the escort had left the visitor in the control room momentarily to obtain a hard hat for the visitor.

On February 21, 1987, the one inch Unit 4 steam line orifice pot line to the northwest extraction steam line was discovered to have a through wall steam leak at a welded joint. Unit 4 was taken off line and placed in Mode II to facilitate the necessary repairs. The affected section of piping containing the degraded weld was replaced and Unit 4 returned to 100% power on February 22, 1987.

On February 21, 1987, Unit 3 was reduced to 60 % power to allow the 3A steam generator feedwater pump (SGFP) to be removed from service to repair a bearing lubricating oil leak. The threads of the lubricating oil piping to the 3A SGFP inboard bearing housing inlet had cracked causing oil to leak freely from the fitting. A new length of pipe was manufactured and the repairs were completed. Unit 3 returned to 100% power on February 22, 1987.

On March 4, 1987, a Class C fire was reported near the Unit 3 equipment hatch. A welding transformer was observed to be arcing and was subsequently de-energized. The cause was attributed to the welding transformer power cables laying in a pool of water.

On March 6, 1987, while performing Intake Cooling Water (ICW) check valve testing, the 3B ICW pump failed to start. The pump was declared out of service and Unit 3 entered a 24 hour LCO. Investigation revealed that the 3B ICW pump DC fuse block in breaker 3AB17 was loose. After reseating the fuse block the pump was successfully started and declared back in service.

On March 6, 1987, Unit 3 was manually tripped from 95% reactor power while reducing turbine load due to high vibration on the #9 exciter bearing. As load was being reduced the turbine control and intercept valves closed. The reactor was manually tripped and all required automatic actions were verified. The cause of the turbine trip was attributed to a control oil system malfunction. At least two recent control oil system problems resulted in unexpected load reductions/trips. On March 7, 1987, a Unit 3 reactor startup was commenced to allow rolling the turbine to determine if any damage had occurred to the #9 bearing. No damage was apparent and the reactor was shutdown in preparation for the cycle 11 refueling outage (originally scheduled for March 15, 1987).