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

Report Nos.: 50-250/85-22 and 50-251/85-22

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: June 3-7 and June 24-28, 1985

Inspectors: S. D. Stadler — Date Signed 8/7/85

D. P. Falconer — Date Signed 8/7/85

H. O. Christensen — Date Signed 8/7/85

Approved by: B. T. Debs, Acting Section Chief
Division of Reactor Safety — Date Signed 8/7/85

SUMMARY

Scope: This routine, unannounced inspection entailed 93 inspector-hours on site in the area of maintenance programs June 3-7, 1985. In addition, another 93 inspector-hours were expended on a reactive inspection June 24 - 28, 1985.

Results: One violation was identified.

Violation: 250, 251/85-22-03 - Failure to establish and implement written procedures to control safety related activities.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*+C. J. Baker, Plant Manager - Nuclear
*+J. W. Kappas, Maintenance Superintendent-Nuclear
*+J. Arias, Jr., Regulation and Compliance Supervisor
*+V. Kaminskas, Operations Superintendent - Nuclear (Acting)
+D. Mojhena, Emergency Planning Coordinator
*R. Acosta, QA Superintendent
*H. Young, Project Site Manager
*+W. Bladow, QA Supervisor
+R. Earl, QC Supervisor
+P. Hughs, Health Physics Supervisor
+W. Miller, Nuclear Training Supervisor
*K. Jones, Technical Department Supervisor
*M, Crisler, QC Supervisor
+L. Gobel, Operator Requalification Training Supervisor
*+R. Hart, Licensing Engineer
*M. Costa, I&C Production Supervisor
*F. Southworth, Technical Advisor
+E. Laplerre, Nuclear Chemistry Supervisor
*+G. Vaux, SEG Engineer
+S. Salzman, SEG Engineer

Other licensee employees contacted included engineers, technicians, operators, mechanics, and office personnel.

NRC Resident Inspectors

*T. A. Peebles, Senior Resident Inspector
*+D. R. Brewer, Resident Inspector

*Attended exit interview June 7
+Attended exit interview June 28
*+Attended exit interviews June 7 and 28

2. Exit Interview

The inspection scope and findings were summarized on June 7, and again on June 28, 1985, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed below. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspector during these inspections.

The following commitments were made at the exit interview in regards to the recent inverter failures:

	Commitment	Projected Completion Date	Responsible Section	Report Paragraph
A.	Complete an engineering study for inverter breaker trip setpoint	Open-Licensee will notify NRC	FP&L Corporate Engineering	9.c
B.	Training			
(1)	Provide on-shift training on new off-normal procedures for a loss of 120 volt vital AC buses	Immediately, as soon as procedures are issued	Operations	9.b
(2)	Provide a short term classroom (lecture) training course on the new off-normal procedures, the bases, and immediate operator actions for all licensed personnel.	Starting Monday July 1, 1985, to be completed for all shifts within one week	Training	9.b
(3)	Provide detailed classroom training on the new off-normal procedures and the immediate and subsequent operator actions	During the next license requalification training cycle	Training	9.b
(4)	Provide training for licensed operators on the interim procedures and instructions to be utilized during the replacement of the twelve static inverters	Prior to disconnecting the first inverter for replacement	Training	9.b
C.	Off-Normal Procedures for Loss of 120 Volt Vital AC			
(1)	Revise procedures to include immediate actions required to stabilize the unit following loss of a vital AC bus	Immediately - prior to distribution	Safety Engineering Group	9a.

(2)	Revise procedures to remove instrument and control (I&C) technicans from responsibility for pulling fuses to close spray valves or holding relays to regain pressurizer heaters. This will be an operations responsibility.	Immediately - ± prior to distrubution	SEG	9A
D.	Apply unique identification (operator aids) to the panel doors and the relays for energizing the pressurizer heaters and fuses to be pulled to close pressurizer spray valves. Also improve lighting near panel containing pressurizer heater relay panels for Unit 4.	As soon as possible, but within one week	Maintenance	9.a

3. Licensee Action on Previous Enforcement Matters

This subject was not addressed in the inspection.

4. Unresolved Items

New unresolved items identified during this inspection are discussed in paragraphs 5, 6, and 9.

5. Corrective Maintenance

The maintenance program at Turkey Point is under a transition which includes applicable areas of the Performance Enhancement Program (PEP), the Performance Improvement Program (PIP) and the Procedures Upgrade Program (PUP). As a result of this substantial transition effort, the maintenance program inspected was a blend of the old program which contained unacceptable deficiencies, an interim program containing short term resolutions, and the long-term improvement program which was only partially implemented in most areas. The inspection placed emphasis on ensuring this present program relating to maintenance activities was in conformance with Technical Specifications, regulatory requirements, commitments and industry standards. The inspectors also attempted, wherever possible, to ascertain the licensee's progress toward, and implementation of, long term maintenance goals such as the automated plant work order (PWO) program.

a. Plant Work Orders (PWOs) - The backlog of plant work orders at Turkey Point was very large, particularly in the instrumentation and control area. The licensee provided a number of contributing reasons for this substantial backlog. There was a shortage of personnel, particularly in the I&C area where qualified personnel are difficult to obtain. In addition, a substantial number of the maintenance personnel are considered "itinerant" and are moved from site to site as needed including the fossil plants. The present backlog, which has increased in the past few months, was also attributed to an increased emphasis by plant management on the necessity to write PWOs on any problems or deficiencies observed. This large backlog of PWOs, which appeared to be increasing, was a source of concern for the inspector. Turkey Point utilizes a two digit alpha-numeric code to assign priorities to PWOs. The letter designations run from AA, which is the highest priority, to E which is the lowest priority. Power Resources (Corporate) Procedure 3310.5 requires that the Maintenance Superintendent assign this work priority letter based on the potential effect on the unit, personnel, plant, and regulatory requirements. These priorities were, in practice, being assigned by the planner/coordinators for each group. The new plant procedure on PWO preparation O-ADM-701, requires the Nuclear Watch Engineer or Plant Supervisor - Nuclear to assign this priority. Interviews with the various planner/coordinators and review of the PWO backlog computer print-outs indicated that these assigned priorities were not receiving a great deal of emphasis in the scheduling of work. B and C PWOs, in some cases, appear to have been worked before A orders which cover safety-related equipment. The concern is that with the number of PWOs and the backlog increasing, additional PWOs may not be worked according to their assigned priority and relative importance to plant safety. The resolution of this abnormally large PWO backlog will be identified as an inspector followup item (250, 251/85-22-01). The licensee has established a new position, Operations/Maintenance Coordinator, that provides an interface between Operations and Maintenance. Having an operations background, the person filling this position should help expedite and set valid priorities for PWOs affecting plant operation and safety.

The licensee has designed an automated PWO system with plans to implement it on a one year trial basis late this year. This computer based PWO program, if it works as designed, will automatically perform many of the manual PWO tasks performed presently by including the determination of whether the work is safety-related and the routing for review to various groups such as QC and NPRDS. Determination of safety-related will be automatically made based on a new expanded "Q" list that contains both safety-related as well as important-to-safety systems and components. This automated PWO program will include CRTS for the interfacing groups such as Operations, Maintenance, QC, NPRDS, etc. This should help improve communications, expedite priority work, and hopefully reduce the backlog of PWOs. The inspectors noted several deficiencies in the present method of processing PWOs and the associated clearances. The planner/coordinator determines whether a PWO is safety-related based on the present "Q" list which does not

include the important-to-safety designation. If the PWO is marked nonsafety-related, then it is never sent to QC for review. Since there may be "grey" areas which may or may not be safety related, the concern is that a PWO may be mis-designated and not caught by QC. The licensee has performed audits of a percentage of completed PWOs and did not observe this problem; however, until the expanded "Q" list is implemented, all PWOs could be reviewed by QC. This would be consistent with the St. Lucie PWO review process.

The planner/coordinator also determines whether a PWO requires a radiation work permit (RWP). There is no formal basis utilized for this determination except a blanket requirement for an RWP for work anywhere in the radiation controlled area. Plant Health Physics Procedure HPA-001 states specific activities or conditions which require an RWP, but the planners were neither familiar with or utilizing this procedure. Because PWOs which are marked "no RWP required" are never reviewed by the Health Physics group, the planner/coordinator should be familiar with these procedural requirements or all PWOs should be reviewed by Health Physics.

According to Section 7.2 of Plant Administrative Procedure AP 0103.4, completed equipment clearance orders which are nuclear safety related constitute QA records and, therefore, shall be retained as records for a minimum of five years. The inspectors requested the clearance associated with a completed PWO reviewed (4256028). The PWOs contain a block for the clearance number to be entered. The licensee was unable, however, to provide this clearance prior to completion of the inspection. Since these clearances contain records affecting quality such as equipment realigned and tagged, independent verification of restoration, and temporary system alignments (TSAs), they should be retrievable per 10 CFR, Appendix B, Criterion XVII. The inability to retrieve QA records relating to a specific PWO maintenance activity will be identified as an unresolved item (250, 251/85-22-02).

b. Maintenance Procedures - The "old" maintenance procedures were inadequate in many areas including scope, QC holdpoints, and in the number of procedures available. The Procedure Upgrade Program appears to be making improvements in this area, but is only partially complete. Specific procedures are being upgraded, along with the associated drawings, as a maintenance task is required to be performed. The inspector verified that safety-related revisions under this program are receiving the appropriate reviews and approval including the Plant Nuclear Safety Committee (PNSC). The new procedure format appeared to be a substantial improvement including content, QC holdpoints, and human factors areas. The inspector reviewed the new procedure on PWO preparation, ADM-701, and found it to be well formatted and to contain detailed information on the responsibilities for and the processing of PWOs.

Many of the activities performed by the Maintenance, I&C, and Electrical sections had not previously been covered by procedures. The

I&C group appeared to be leading the way in the effort to increase the number of procedures available to cover the various maintenance activities. I&C is the first Turkey Point section to develop a procedure to cover troubleshooting. This procedure requires logging, in detail, each troubleshooting activity performed and deficiency identified. This should prove very useful in the post-analysis and corrective maintenance. The Maintenance section also appeared to be making significant progress toward developing and implementing procedures to cover the various maintenance tasks. As an interim measure for maintenance work not yet addressed by procedures, the maintenance planners provide a detailed list of instructions on the associated PWO. The Electrical group appeared to be lagging far behind in the development of procedures with only a very few procedures in place to cover the numerous electrical maintenance activities. The reliance for guiding of activities appeared to place heavy emphasis on "skill-of-the-trade" and the use of electrical drawings. A review of several electrical PWOs for activities not covered by procedures did not indicate the detailed instructions provided on comparable maintenance PWOs. The PWOs contained very broad directions such as "troubleshoot" or "replace the breaker". Such broad directions do not ensure that a task is performed correctly or that it is performed the same way each time. In addition, since the individual steps are not identified in a procedure or on the PWO, the determination of appropriate hold points by QC can be very difficult making their input inadequate.

Plant management at Turkey Point appears to be solidly behind strict compliance to procedures in all areas. On January 26, 1984, the Plant Manager issued a letter to all nuclear plant personnel strongly emphasizing the need to strictly adhere to procedures. Another letter was written on June 3, 1985, and distributed during the inspection. This letter stated that a number of recent events had indicated a definite need to remind all personnel of the verbatim procedure compliance policy. The letter states that "no foreman or any supervisor, including myself, has the authority to instruct anyone to do anything contrary to the instruction of a procedure. This includes omitting procedural steps". The inspectors consider this strong emphasis by the Plant Manager on procedural compliance to indicate a very positive management effort. In contrast, the present lack of procedures, particularly in the Electrical Maintenance area, the lack of specific instructions on some PWOs, and the continued reliance by some staff supervisors on "skill-of-the-trade" do not appear to fully support this emphasis. Plant administrative Procedure 0190.19, Control of Maintenance on Nuclear Safety Related and Fire Protection Systems, states that "skills normally possessed by qualified maintenance personnel do not require detailed step-by-step delineation in a procedure". Strict compliance with procedures requires, first, that an adequate number of procedures be written and implemented. Hopefully, the Procedure Upgrade Program will accomplish this and thus allow verbatim procedural compliance in all safety-related and important-to-safety activities.

c. Static Inverter Problems - The licensee has experienced a number of problems with the static inverters which supply vital 120 volt control power. In 1984, there were several turbine runbacks attributable to problems with the power supplied by these inverters. On September 20, 1984, Unit 4 tripped from 100% power as a result of a trip of the 4A static inverter (LER 84-021). On October 9, 1984, Unit 4 tripped during a startup, again, as a result of the 4A static inverter (LER 84-22). When the operators attempted to manually transfer to the spare (AS) inverter as they had on September 20, the spare inverter also tripped. Subsequent investigation by the Electrical Maintenance group revealed a wiring error in the D.C. filter section of the 4A inverter. The filter and capacitor were installed in reverse order, providing less efficient filtering against disturbances in the D.C. supply circuit. These disturbances can cause misoperation of the logic circuit by shorting across the D.C. input, clearing the D.C. bus supply breaker and D.C. input breaker, and blowing fuse F6. This miswired D.C. input filter circuit was rewired and corrected by the Electrical Maintenance group following the second reactor trip and discovery of the deficiency.

10 CFR 50, Appendix B, Criterion V, requires that activities affecting quality shall be prescribed by documented instructions or procedures and that the instructions and procedures contain appropriate acceptance criteria for determining that important activities have been satisfactorily accomplished.

Section 6.8.1 of Turkey Point Technical Specification states that written procedures and administrative instructions shall be established, implemented and maintained that meet or exceed the requirements and recommendations of Section 5.1 and 5.3 of ANSI 18.7-1972, and Appendix "A" of Regulatory Guide 1.33.

Contrary to the above, the licensee did not establish adequate instructions, procedures, and quality controls to ensure the proper wiring of the D.C. input filter section to inverter 4A. In addition, this miswiring was not discovered until it had contributed to two full power runbacks and reactor trips. Also, PWO 407615, under which the circuit was rewired, provided no documentation of the specific work performed, of the steps required to accomplish the evolution, or of any QC hold points as required by Administrative Procedure AP 0190.19, Control of Maintenance On Nuclear Safety Related and Fire Protection Systems. This failure to establish or implement adequate procedural and QC controls over the installation of a safety-related component, and over the rework required to correct the deficiency is a violation (250, 251/85-22-03).

These problems with static inverters at Turkey Point have continued this year and appear to be increasing in frequency. There have been numerous problems in 1985 with these inverters including several trips while on dummy loads for troubleshooting. On May 30, 1985, the 4A inverter tripped resulting in a rod drop signal, a turbine runback, and

a reactor trip from 100% power. On June 6, 1985, Unit 4 was at 100% power. Inverter 4C was feeding vital bus 4P06 (Unit 4) and the spare inverter (CS) was feeding Unit 3 which was in refueling. The third inverter, 3C, had tripped several times and was on a dummy load in an attempt to determine the problem. The 4C inverter tripped causing a loss of vital power to instrument panel 4P06. The operators attempted to place the 3C inverter in service but that inverter also tripped when the first load breaker was closed. With no vital power available to panel 4P06, the operators lost a number of controls including the pressurizer heaters and the pressurizer spray control valve. The combination of no pressurizer heaters and the pressurizer spray valve lockup, apparently in the partially open position due to the loss of vital power, resulted in reactor pressure decreasing rapidly and coming within approximately 12 pounds of a safety injection (SI) signal. The heaters were restored and a low pressure SI signal prevented by manually holding pressurizer heater relays in. The spare (CS) inverter which had been suppling Unit 3 in refueling was then borrowed and placed in service on Unit 4. This action left Unit 3 without power to the source range monitors for a period of time.

The off-normal procedure utilized by the operators to transfer to a back-up inverter had been written in 1984 in response to an inspection finding and civil penalty. The enforcement action was taken because the licensee had never established a procedure for transferring vital power supplies. This lack of a procedure prevented the operators from being able to transfer inverters following the inverter and reactor trips on September 20, 1984. The original procedure written called for transferring inverters onto a loaded bus with all breakers closed. Tests performed by the licensee in October 1984 indicated there was only a 50-50 chance that the inverters could be expected to successfully pick up a dead load in this manner. The procedure was revised to require that all load breakers be opened prior to the transfer and then reenergized sequentially after the inverter transfer. This procedure was utilized on June 6, 1985, but the 3C inverter still tripped when the first load breaker was closed. In addition, the off-normal procedure was significantly deficient in that it did not list the controls that would be lost with any specific vital bus, and the appropriate compensatory actions for operators to take. In this particular case the procedure provided no direction on how to restore pressurizer heaters, to stop the pressurizer sprays, or to establish pressure control. In past inverter/reactor trips, the procedure failed to address other control losses and the appropriate corrective actions including a loss of letdown flow due to valve closure and a PORV going to the full open position. These deficiencies were the subject of enforcement actions detailed in IE Report 250, 251/85-20.

Interviews with plant personnel reflect very little confidence in the reliability of any of the twelve presently installed static inverters. The electronic filter circuits are apparently not capable of handling normal plant electrical fluctuations and transients and appear to be deteriorating. The Licensee Event Reports(LERs) generated following

many of the turbine runbacks and reactor trips due to inverter trips conclude that the exact cause had not been clearly established, i.e., no dead grounds, etc. The licensee has long-range plans to replace all twelve of these inverters with a more reliable design and also to redesign the circuits to provide an alternate feed source and automatic throwover. Six of these new inverters were already on site at the time of the June 3-7, 1985 inspection and the other six on order. Details of the licensee's schedule for installation are contained in paragraph 9.e of this report.

d. Maintenance Activities and Housekeeping - The inspector observed portions of on-going maintenance activities including work on an auxiliary feedwater pump and the closed cooling water system. The protective tagging, work activities, and safety precautions appeared adequate in all observed areas. Plant Administrative Procedure 0103.11 provides very detailed housekeeping controls and establishes responsibilities for plant housekeeping and cleanliness. The procedure requires a housekeeping inspection by each department on a monthly basis. A walkthrough of various plant areas by the inspector indicated that the housekeeping controls were adequate. The areas around equipment involved in several recently completed PWOs were inspected and found to be clear of tools and debris. The inspector noted that on a number of completed PWO journeyman reports, the maintenance personnel had specifically documented their cleanup activities following completion of the work.

The inspector reviewed PWO 5407 to troubleshoot and repair the 4AA05 and 4AB05 Bus Supply Fans. On May 17, 1985, control room operators had noticed that the bus supply fans were not operable while restarting Unit 4 following a reactor trip. Investigation of power supply breakers and fuses revealed that the bus supply fans were inoperable due to Breaker 40521, on the 4A Motor Control Center (MCC), being in the off position (open). The breaker was subsequently racked-in to restore power to the bus supply fans. The last manipulation of Breaker 40521 had occurred when the 4A MCC tripped earlier that day. Operators, in an attempt to restore power to the 4A MCC, had stripped all 4A MCC loads, closed the 4A MCC supply breaker to its power source, and reloaded the MCC. During this evolution, the operator apparently failed to close Breaker 40521, thus rendering the 4AA05 and 4AB05 Bus Supply Fans inoperable.

Operators did not utilize procedures to return the 4A MCC to service after it tripped. A review of the licensee's procedure index indicates that procedures have not been established to contend with a loss of the 4A MCC. The lack of approved written procedures addressing this abnormal condition contributed to the operator's failure to return Breaker 40521 on the 4A MCC to its normal configuration.

Technical Specification 6.8.1 requires that written procedures shall be established, implemented and maintained that meet or exceed the requirements of Appendix A of USNRC Regulatory Guide 1.33. Regulatory

Guide 1.33 requires that procedures be established for Abnormal, Off-normal or Alarm Conditions. Contrary the above, the licensee failed to establish procedures to contend with a trip of the 4A MCC. This is another example of violation (250, 251/85-22-03), Failure to Establish Adequate Procedures.

The inspector reviewed PWO 8382, initiated on June 20, 1984, to troubleshoot and repair control room annunciator H2/6 (Unit 3 'C' Accumulator Hi-Low Level) which was locked-in. Maintenance was begun on June 29, 1984, and continued through July 6, 1984, when the cause of the malfunction was determined to be excessive AC on the transmitter signal in containment. The final entry in the journeymans work report stated "comparator output fuse pulled & TSA (temporary system alteration) filled out". On August 30, 1984, the licensee performed additional maintenance on the loop to allow reflash capability until the loop could be repaired during the next outage. During this evolution, the licensee noted that the original TSA tag was not in place and not logged in the TSA logbook. TSA documentation was resubmitted and the PWO placed in the outage work files. The PWO was finally completed in December 1984 during a plant outage.

The inspector requested that the licensee retrieve the documentation of the July 6, 1984, temporary system alteration to the 3C accumulator Hi-low level circuit. After an extensive search of plant records, the licensee was unable to locate this documentation.

Administrative Procedure 0103.3, Control and Use of Temporary System Alterations, indicates that documentation associated with TSA issuance constitute quality assurance records and, therefore, shall be retained in accordance with Administrative Procedure 0190.14, Document Control and Quality Assurance Records.

Technical Specification 6.8.1 requires that written procedures shall be established, implemented and maintained that meet or exceed the requirements of Appendix A of USNRC Regulatory Guide 1.33. Regulatory Guide 1.33 requires that administrative procedures be established for equipment control and record retention.

Contrary to the above, the licensee failed to maintain documentaion of the July 6, 1981 temporary system alteration pursuant to Administrative Procedure 0103.3. This is another example of violation (250, 251/85-22-03), Failure to Implement Approved Procedures.

6. Preventive Maintenance (PM)

The licensee's Preventive Maintenance (PM) program was reviewed to determine if it conformed with Technical Specifications, regulatory requirements, and commitments made to industry standards. The inspector reviewed the PM programs established by the Electrical, Mechanical and Instrumentation and Control departments. Additionally, the inspector interviewed the Generating Equipment Maintenance System (GEMS) planners of each department

and the Special Projects - PM Program Manager. Finally, the inspector reviewed selected plant work orders on PMs and observed the performance of one PM in progress.

Turkey Point's PM program is under a review process by management. This review will consist of an evaluation of the present program, followed by a gradual implementation of program improvements. At this time, the review process is just starting with no course of action determined.

The current program for each maintenance department is a computerized PM program which automatically performs the following functions for the GEMs planner:

- Prints a list of PM jobs which are to be issued for the week and of which jobs have been completed.

- Produces a PM schedule report showing all of the uncompleted PM jobs in priority order and provides the number of days behind schedule.

- Provides a master file of all PM jobs with the scheduled PM frequencies.

Once the GEMs Planner has the computer print-out on the PM job schedules for the week, he assembles a PM plant work order (PWO) package which includes the work procedure or maintenance instructions, data sheets, and retest requirements if required. The planner also reviews the package to determine if the PM is safety-related using a Q list as a guide, and if it is, the PWO will receive a PM work review by quality control. The work package is then issued to the appropriate maintenance supervisor for completion.

The inspector noted the following:

- The Electrical and I&C departments have not established procedural methods for providing overdue PM follow-ups. The mechanical department has a procedural (Preventive Maintenance Program - Mechanical Procedure AP-0720) requirement to provide a list of uncompleted PM's to the maintenance supervisor and also to provide once a month a list of all safety-related PMs uncompleted to the Mechanical Superintendent. This followup program is to assure proper emphasis on completion or an appropriate determination for delaying the PM.

- The GEMs planners determined if the PWO is safety related, and if it is not, quality control does not conduct a pre-screening of the PWOs to determine if it has been designated correctly or if the PM needs QC holdpoints. The licensee informed the inspector that they do perform a post QC review on all completed PWOs. This review is not documented on the non-safety related PWOs. Additionally, the licensee informed the inspector that they plan to commence a 100% pre-work QC screening of all PWO's. The inspector noted that all I&C PMs receive QC pre-sreening, but not all Electrical and Mechanical PMs receive pre-screening.

- The Electrical and I&C Gems planners maintain a manual PM tracking system. I&C Gems planners use this tracking system for Technical Specification required PMs and Electrical Planners use it for all PMs. This type of tracking system has proven useful, in that it allows the planner to maintain a long range schedule that shows the completion trends of PMs. The planners can determine if PMs are frequently being delayed and, in the case of I&C planners, if the PM frequencies are being completed in the plus or minus 25% time interval as required by Technical Specifications. An additional benefit of the manual tracking system is that it provides a backup for the computer system and if the computer fails, the planner can still schedule PMs. Also the inspector noted that the computer tracking system sometimes does not record a completed PM. The Electrical GEMs planner informed the inspector that the PWO computer tracking system occassionally has interface problems with the PM computer system, in that the PM system does not pickup the completion status from the PWO tracking system. An example of this is the electrical PM-3018, station battery 4C (Aux DC system). The computer schedule showed the PM overdue by four months, but the manual system had documented its completion.

- The present PM program does not have a procedural method for evaluating the effectiveness of PMs and adjusting the scheduling frequencies. Additionally, the responsibility for establishing PM frequencies is not defined. The PM planners do, on an informal basis, receive feedback from their maintenance supervisors on the adequacies of PMs, and recommendations for changes in PM frequencies.

The inspector reviewed the status of overdue PMs and noted the following:

a. The I&C PM schedule showed that all post accident sampling system (PASS) PMs were four months overdue. These PMs are:

   - PM-94005, PASS Dissolved Oxygen Analyzer
   - PM-94006, PASS Liquid PH Analyzer
   - PM-94007, PASS Hydrogen Analyzer
   - PM-94008, PASS Sample Pressure
   - PM-94009, PASS Gas and liquid flow monitor calibration
   - PM-94010, PASS Inlet and cooled sample temperature monitor calibration

   The inspector was informed by the GEMs planner that the PASS PMs were delayed due to PASS modifications. The inspector informed the licensee that the PASS PMs and system status will be an unresolved item, until a future inspection can determine the significance of a four month delay on performing these PM (250, 251/85-12-04).

b. The I&C PM-74035, Perform MP 0707.8, Calorimetric Instrumentation Periodic Calibration, was due February 17, 1985, making the PM four months overdue. The inspector was informed by the I&C department that the PM was not performed on time because the department wanted to change the PM frequency requirement from 153 days to annually. During

this four month delay period, the I&C department took no action to evaluate the significance of changing the PM frequency, or to determine the effect of a delay in performing the PM.

The calorimetric instrumentation periodic calibration PM is utilized to calibrate instrumentation used in thermal power calculations. Technical Specifications for nuclear power range instrumentation requires a thermal power calculation daily. This thermal calorimetric is dependent on the instruments calibrated by PM-74035. Operating procedure 12304.3, Power Range Nuclear Instrumentation Shift Checks and Daily Calibrations, requires that reactor power range meters be within ±1 percent of the thermal calorimetric when reactor power is equal to or greater than 90 percent. The reactor engineer who performs the daily calorimetric informed the inspector that a one degree change in feedwater temperature would cause a 0.25 percent change in reactor power. The inspector reviewed the last calorimetric instrumentation periodic calibration PM performed in August 1984 to determine if there was sufficient evidence to delay the PM. The following instruments were recalibrated or replaced.

(1) A square root extractor for steam generator 'C' blowdown flow rate would not calibrate and had to be replaced.

(2) DDPS feedwater flow detectors for steam generators A, B, and C detectors were out of tolerance and had to be calibrated.

(3) The feedwater temperature, DDPS analog channel one, was within tolerance (±2.25°F) but the error of the instrument over the temperture range 280°F - 474°F varied from 1.18° to 2.11°F.

(4) Main steam pressure header transmitter "C" was out of tolerance and had to be calibrated.

The above results would not appear to justify extending the calibration frequency to a yearly PM.

Administrative Procedure 0190.26, Calibration Control of Installed Nuclear Safety Related Instrumentation and Control Equipment, section 8.5.1, states, "any installed instrumentation or control equipment out of calibration, past due calibration, or requiring repair shall be repaired or recalibrated as soon as practical, taking into account the relative importance of the device." Florida Power and Light's, inter-office correspondence dated August 23, 1984, on DDPS Technical Specification required channels, lists the DDPS instrumentation required to conduct a calormeteric, which is a safety-related calculation.

10 CFR, Appendix B, Criterion V, states that activities affecting quality shall be prescribed by documented instructions, procedures or drawings, of a type appropriate to the circumstances and shall be

accomplished in accordance with these instructions, procedures, or drawings.

10 CFR, Appendix B, Criterion XII, Control of Measuring and test equipment states, measures shall be established to assure that tools, gages, instruments and other measuring and testing devices used in activities affecting quality are properly controlled, calibrated and adjusted at specified periods to maintain accuracy within necessary limits.

Contrary to the above, the licensee failed to perform PM-74035, Calorimetric Instrumentation Periodic Calibration, MP-0707.8 at the frequency designated by the computerized preventive maintenance program file of 153 days and failed to conduct the calibration in a timely manner as specified by Administrative Procedure 0190.26, section 8.51.

The four month delay in completing PM-74035 is another example of violation (250, 251/85-22-03), Failure to Implement Approved Procedures.

7. Special Processes

The inspector reviewed the licensee's maintenance and QA programs to ensure that special processes are administratively controlled and accomplished with qualified procedures in accordance with applicable codes, standards, and specifications. The inspector verified that for applicable special processes, the licensee maintained current and proper certifications and qualifications of personnel designated to perform these functions. Selected special processes underway in the plant were observed by the inspector and several completed plant work orders were reviewed to verify that they had been accomplished in accordance with the licensee's program.

The licensee has recently established a new welding program with improved controls appropriate for an operational facility. The new program is implemented by administrative procedure 0190.80, Control of Welding Special Processes. The procedure includes administrative instructions pertaining to all welding, brazing, soldering and heat treating performed on plant equipment and establishes the welding control manual. The Welding Control manual provides the specific instructions, including engineering standards, technical specifications, and welding procedures necessary to accomplish these special processes at Turkey Point.

All personnel who perform welding special processes are required to be trained, qualified and certified. Provisions for requalification of welders is under the cognizance of the welding supervisor.

Currently, the licensee maintains certifications for nine welders who perform routine welding maintenance activities on plant primary and secondary systems. The inspector verified that selected welder certification records were complete and maintained in accordance with quality assurance requirements.

The inspector observed one welding activity (PWO 229) to repair steam eroded piping on a steam trap lower tap and reviewed one complete welding activity (PWO 2018) to repair a leaking pipe on the 3A RHR Pump seal water heat exchanger. These activities were accomplished in accordance with the licensee's welding program. A review of weld filler material control indicated that weld materials were controlled and required proper authorizations and verifications prior to use.

Overall, the new welding program was well implemented and provided the necessary administrative and technical controls to assure that quality is maintained for all welding activities at Turkey Point.

The nondestructive examination (NDE) special processes are accomplished by the quality control organization. Implementation of the NDE program is accomplished by Quality Instruction (QI) 9.2, Control of Nondestructive Examination Activities. QI 9.2 provides administrative controls, specifies responsibilities, and defines the scope of the NDE program at Turkey Point. QI 9.3, NDE Personnel Qualification and Certification specifies the experience, training and certification required to perform NDE activities.

The inspector reviewed current certification records and selected maintenance to verify that all plant NDE activities were accomplished by qualified personnel. The plant QC organization presently maintains certifications for two QC inspectors. These inspectors are only certified to NDE Level II in the area of liquid penetrant testing. The inspector verified that their certification records were complete and maintained in accordance with quality assurance requirements. Due to the small number of NDE certified personnel in the plant QC organization, the licensee relies heavily on NDE support from the "backfit" organization. The scope and number of plant QC inspectors that are NDE certified should be increased to assure that adequate QC personnel are qualified to support routine plant maintenance activities requiring NDE when the "backfit" organization completes work at Turkey Point.

8. Operational Experience Feedback

The Operational Experience Feedback Program for Turkey Point is described in Administrative Procedure AP 0103.15 including the objectives, manner of distribution, administrative controls, and organizational interfaces. The stated overall objective of the program is to ensure that significant operating experiences are systematically evaluated and lessons learned are incorporated into appropriate corrective actions to promote plant reliability and safety. Among the more specific objectives listed are the following:

a. The program should ensure that significant operating experiences and their corresponding recommendations and/or corrective actions are reviewed and approved as appropriate by experienced technical personnel.

b. The results of operational experience evaluations are disseminated to operators, maintenance, engineering and other personnel as appropriate in a timely manner.

c. The program should provide a means for documenting the disposition of operating experience information and resultant actions taken.

Although the Technical Department Supervisor has the overall responsibility for administration of the Operational Experience Program, the Operations Support Engineer has the primary responsibility for program implementation. The responsibilities of the Operations Support Engineer include selection of event reports for review by the Plant Technical Review Board (PTRB), screening reports for urgent staff notification, and maintaining a file of event reports, and a log of the status of all active items. The plant superintendents for each work group such as Maintenance and Operations are responsible for the dissemination of completed evaluations to personnel under their supervision and for the completion of required actions in a timely manner. Operational experience reports which are sent to the PTRB for review are then assigned by that group to the technical department which is considered best suited to perform the evaluation. The engineer performing this evaluation is responsible for determining if the report identifies any inadequacies or problems associated with plant design, procedures, components, training or operating practices, and any corrective actions that are required. For items not deemed appropriate for PTRB evaluation, the procedure requires that they be distributed or applicable to all plant departments for review, particularly those reports which involve personnel error.

The inspectors reviewed the operational experience feedback files for six NRC I&E Information Notices issued within the past year to determine their disposition. This review led to the following observations and concerns:

- The program appears to be functioning well in determining corrective actions required such as procedure changes, design changes, human factors improvements, etc.

- Although all of the I&E Notices reviewed had been closed out or completed except one, the time between receipt and final PTRB approval appears to be excessive (from five to nine months on those for which any action was taken).

- The procedure does not appear to require that reports which receive PTRB review be sent to other plant departments for review as with reports not requiring PTRB review. PTRB assigns the reports for engineering evaluation, and these evaluations are eventually distributed to other departments. The concern is that information, particularly when it involves personnel error which could be repeated, is significantly delayed in reaching departments performing similar functions.

- The procedure does not address in any detail how operational experience feedback information is to be disseminated at the working level, i.e: to the individual operator, mechanic, electrician, or I&C technician. The review of these I&E Notices indicated that while some of the material was presented to operators as required reading or in requalification training, none of the information was provided or documented as training for mechanics, electricians, or I&C technicians. At least three of these Notices, Wrong Unit/Wrong Train (84-58), Personnel and Procedural Errors (84-51), and Lifted Leads and Jumpers During Surveillance and Maintenance Testing, were applicable to these classifications. The present program appears to place emphasis on changing procedures utilized by these personnel as opposed to documented training. This methodology does not emphasize to the individuals important areas such as causes of specific events including personnel errors, the applicability to their plant, the potential results of incorrect actions on plant operations and safety, and methods that can be utilized to prevent reoccurrence. Only by providing this type of training through required reading, discussion, or in the classroom, can the true impact of operating experience events be imported to individuals at all levels and repetition of errors eliminated. This training would meet the intent of NUREG 0737 Item 1.C.5 and the objectives stated in AP0103.15.

- NUREG 0737 Item 1.C.5 requires that periodic interval audits be performed to assure that the feedback program functions effectively at all levels. The inspector reviewed Turkey Point Audit QAO-PTP-85-609 which audited the Operating Experience Feedback Program. This audit and interviews with QA staff personnel indicate that the audits are only down to the plant superintendents' level, and do not include distribution to and training for mechanics, electricians, and I&C technicians.

  The providing of operating experience feedback as applicable to these personnel in some form of documented training, and the auditing by QA of the program effectiveness at all levels will be inspector followup item (250, 251/85-22-05).

- The response to I&E Notice 85-22, Failure of Limitorque Valves on Incorrect Pinion Gear Installation appeared very good. The licensee generated a temporary procedure, TP166, to include the corrective actions identified in the Notice. This timely response should help prevent valve failures attributed to this cause from occurring at Turkey Point.

- Turkey Point Technical Specification 6.10.2.g. requires that training records be maintained for a duration of the operating license or duration of employment. Section 7.1 of Administrative Procedure AP 0103.15 requires that each department retain records of personnel trained or feedback items for a minimum of only six months. The modification of the procedure to be consistent with the Technical Specification will be inspector followup item (250, 251/85-22-06).

9. Reactive Inspection

A reactive inspection was conducted at Turkey Point from June 24 to June 28, 1985, in response to a reactor trip on June 20, 1985. On June 20, while loading up the 3C inverter following PC card alignment inspections, the DC input breaker was closed prior to placing the charge-discharge switch to charge and receiving the red charged light pursuant to approved procedure MP 9707.1. This resulted in the 3C inverter input breaker tripping out and the F6 fuse blowing. The 4C inverter DC input breaker also tripped due to the resultant disturbance in the electrical system. Tripping of the 4C inverter led to a Unit 4 runback on a rod-drop signal, and ultimately to the trip of Unit 4 reactor.

Interviews indicated that neither the individual performing the evolution on 3C inverter, nor the two supervisors present, had the approved procedure in hand or checked off the applicable steps as completed. This failure to properly implement approved procedures is another example of violation (250, 251/85-22-03).

Other areas inspected in response to the June 20, 1985 inverter/reactor trip, as well as other inverter trips which have recently occurred at Turkey Point, include the following:

a. Upgrade of Loss of 120 Volt Instrument Panel Procedure

Review of the loss of 120 volt vital instrument panel procedures approved by the plant manager on June 25, 1985, indicated that these procedures have been upgraded to provide operators with technically sound and complete contingency instructions for a loss of each 120 volt vital instrument panel. Efforts by the safety engineering group (SEG) to improve these procedures began following a similar transient on June 6, 1985, and the subsequent identification of procedural deficiencies concerning restoration of pressurizer heaters, termination of pressurizer spray and restoration of letdown flow.

The current procedures were developed following a comprehensive technical evaluation by the SEG of the consequences and effects of a loss of 120 volt vital power. The evaluation consisted of the following elements:

(1) Determination of indications and controls that would be lost on the loss of each vital bus

(2) Determination of which indications and controls lost are important to plant safety

(3) Determination of the consequences of losing these indications and controls

(4) Determination of alternative methods of control or indication

(5) Determination of preferable alternatives

(6) Determination of how to recover the lost bus, controls, and indications

(7) Determination of operator actions to mitigate the transient and achieve plant stability

The procedures have been divided into three scenarios providing continuing instructions for a loss of 120 volt vital power;

CASE A - with turbine runback
CASE B - without turbine runback
CASE C - with reactor trip

The procedures are structured such that operator action is directed towards achieving stable conditions, establishing critical control and indication functions, and finally restoring power to the lost bus. The inspectors consider this methodology effective in directing operator actions during a loss of 120 volt vital power.

The following concerns were identified:

(1) Operating experience in response to inverter/reactor trips indicates that several steps listed as subsequent operator actions in the procedures would be more appropriately categorized as immediate operator actions. These steps are those actions taken by operators within the first few minutes of the transient to mitigate the consequences and to achieve plant stability. Designating these steps as immediate operator actions would place proper importance on their conduct, and ensure that sufficient training is conducted to maintain adequate operator knowledge necessary to promptly respond to a loss of 120 volt vital power.

In response to this concern, the licensee committed to revise the loss of 120 volt vital instrument panel procedures to include immediate operator actions to be taken to stabilize the unit following loss of a 120 volt vital bus. This will be identified as an inspector follow-up item (250, 251/85-22-07).

(2) The procedures require that the operators respond promptly to the plant depressurization due to the pressurizer heaters locking-out and the pressurizer spray valves failing (as is). These actions include locating and manually jumpering relays or pulling fuses. The inspectors expressed concern that unique and highly visible identifications were not provided to aid operators in locating the proper fuses and relays. In addition, adequate lighting was not available for the Unit 4 cabinet containing the pressurizer heater relays.

In response to these concerns, the licensee committed to provide appropriate identification for the relays and fuses and to provide adequate lighting for the cabinet containing the pressurizer heater relays on Unit 4. This item will be identified as an inspector followup item (250, 251/85-22-08).

The procedures contain a note that allows I&C department personnel to remove power fuses to close the pressurizer spray valves. I&C department personnel were not subject to the commitments to train plant operators on the loss of 120 volt vital instrument panel procedures contained in paragraph 9.B. The licensee committed to remove this allowance from the procedures, and will not require I&C department personnel to be knowledgeable on these procedures. Removal of the allowance will be identified as an inspector followup item (250, 251/85-22-09).

b. Training

The numerous recent revisions to the off-normal operating procedures for loss of a 120 volt vital bus have created a need for additional operator training. The latest revisions which were approved during this inspection period provide a comprehensive list of controls and instrumentation that will be inoperable with the loss of any specific 120 volt vital bus. This list is contained in attachment 1 to the procedure and should better prepare operators to handle this type of transient. The two on-the-spot-changes (OTSCs) that were implemented for these procedures in response to inverter/reactor trips on June 6 and on June 20, 1985, contained different methods for regaining pressurizer pressure control. OTSC 3210, which was implemented following the June 6 transient, required tripping the reactor coolant pumps to control the depressurization. The latest procedure revisions do not require tripping these pumps, but require manually holding a relay to energize pressurizer heaters, and pulling fuses to close the pressurizer spray valves. In addition, the procedure format has been changed substantially and immediate operator actions added. Indications were that due to these rapid multiple procedure revisions, that some confusion existed and operators were not totally familiar with the latest procedures and operating philosophy. To ensure that the operators are knowledgeable of these latest procedures, and prepared to adequately handle additional inverter/reactor transients, the licensee committed to provide additional training in several forms as follows:

(1) The Operations Group will provide immediate on-shift training on the new off-normal procedures for loss of 120 volt vital AC buses. The shift supervisor will lead a training discussion which emphasizes the differences in the new procedure revisions including the deletion of the tripping of the reactor coolant pumps, controls and instrumentation that will be lost, and the location of the pressurizer heater relays and the fuses for pressurizer spray valve control.

(2) The Training Department will provide a short term training course on the new procedures for all licensed personnel. This will be approximately a one hour classroom course which will utilize newly acquired photographic mock-ups of the control panels. Emphasis will be on immediate and subsequent operator actions, the bases for these actions, and controls and instrumentation lost with each vital bus and alternatives available. A limited amount of plant and control room walkthrough will also be conducted to point out applicable equipment such as the pressurizer heater relays and pressurizer spray valve fuses. This training was to begin on Monday, July 1, and be completed for all shifts within a few days.

(3) More detailed training on the new procedures for a loss of 120 volt vital buses will be scheduled as part of the next requalification cycle. This training will include testing to ensure understanding of the new procedures and the immediate operator actions contained therein.

(4) The Training Department will provide training on the interim procedures and instructions to be utilized during the changeout of the 12 inverters which supply the vital AC buses. Included in this training should be such interim operations as transfer from the in-service inverter to the new standby Constant Voltage Transformer (CVT), maintenance of synchronism during transfer, transfer from the CVTs to the standby inverter, and a loss of offsite power during this transition period. This training will be provided to all licensed operators prior to disconnecting the first inverter for replacement.

The completion of these training commitments for all licensed personnel at Turkey Point will be inspector followup item (250, 251/85-22-10).

c. Static Inverter Maintenance Activities

The inspectors reviewed the licensee's periodic maintenance program and maintenance history of the Exide static inverters. The licensee has instituted several revisions (on-the-spot-changes 3245, 3275, 3292 and 3297) to procedure MP 9707.1, Inverter Periodic Inspection, in efforts to improve inverter reliability. Inspections utilizing this procedure revealed cleanliness and hardware deficiencies which may have contributed to the inverter failures.

A chronology of inverter problems which occurred during the 1985 calendar year is detailed below:

Recent Inverter Problems

DATE	INVERTER	IMPACT ON UNIT(S)	CAUSE, MAINTENANCE ACTION
04-05-85	4A	Inverter tripped but was on standby.	F6 found blown, replaced voltage Regulator and buffer AMP cards and returned to service

04-07-85	3A	Inverter tripped resulting in a loss of instrumentation power to 3C train.	Shorted C12 capacitor, replaced F6, fuse and C12 and C11 capacitors.
05-30-85	AS	Inverter tripped resulting in Unit 4 tripping off line	Unknown cause, replaced fuse F6, checked capacitors C11 and C12 found OK, performed logic and SCR test and found satisfactory.
05-30-85	4A	Inverter tripped causing loss of instrumentation power. Inverter failed while loads were being connected.	Unknown cause, replaced fuse F6 no other problems were found.
06-06-85	3C	Inverter tripped. Unit 3 was down for refueling. Lost instrumentation and control power on C train. Also, this failure caused Unit 4C to trip due to low setting of 4C inverter DC input breaker (determined at later dated 6-20-85)	Found internal ground on DC side through buffer amplifier diode. buffer amp card replaced
06-06-85	4C	Inverter tripped and Unit 4 tripped off-line	Fuse 6 replaced and unit restarted. Failure suspected to be due to grounded NIS rack. Could also have been due to 3C failure as identified later on 6-20-85
06-06-85	CS	Inverter tripped but was not carrying load	Suspect inverter failed when switching to pick-up renergized DC panel (Unit 4). Fuse F-6 replaced and inverter re-energized.
6-19-85	BS	Inverter tripped but unloaded and no effect on operating units	Found heat sensitive transistor on buffer AMP card. Replaced card wrapped logic check with blanket and inverter worked OK. Returned B5 inverter to standby service.
06-20-85	3C	Unit 3 was shut down for refueling, and C train loads were on the CS inverter as 3C was out for maintenance. Unit 4 4C inverter DC input breaker opened due to failure of 3C inverter which imposed a transient on 3B DC bus	Personnel error. Replaced F6 fuse. No other problem found.

06-20-85	3C	Inverter tripped again resulting in Unit 4 (4C) inverter tripping causing loss of instrumentation power to 4C train,	Replaced Fuse 6, checked out logic, SCRs capacitors, internal grounds, realigned P.C. cards. No problems found.
06-20-85	4C	Unit 4 tripped off line	Inverter input DC breaker open, no other problem found inverter re-started.
06-20-85	4C	Loss of instrumentation power to 4C train	Inverter input DC breaker open. Evaluation of events lead to check/ survey of all inverters input DC breakers setting. 4C breaker was found at 2 and was changed to "Hi" (>8) to eliminate interaction with 3C inverter. During troubleshooting of 3C inverter, 3C was tripped on purpose, and 4C was not affected indicating that the "Hi" setting eliminates the interaction of 3C and 4C.
06-24-85	3C	Inverter tripped resulting in a loss of instrument power to 3C train. No effect on 4C instrumenta-tion/controls and Unit 4.	Suspect inverter was bumped by construction personnel in the area. During troubleshooting all test/ checks made came out OK, except "Bump Test" on logic cage. When bumped slightly on lower left (volt reg. card) corner of cage inverter failed blowing fuse F6 ...parts are on order to replace motherboard receptacles.

Following the June 20, 1985 transient due to an interaction between the 3C and 4C inverters, the licensee identified a problem with the inverter input breaker trip settings. The inverter interactions appear to be the result of poor breaker coordination due to incorrect settings of the breaker trip setpoints. Apparently, these setpoints were never specified by the vendor or determined by licensee engineering evaluation. After identifying this problem, the licensee adjusted the trip settings as detailed below:

INVERTER ID	INPUT RANGE	AS FOUND SETTING	AS LEFT SETTING	BREAKER/ P/N*
3A	150-480	8	8	1
AS	150-480	6	6	1
4A	150-480	6	6	1

3B	160-560	Hi	Hi	2
BS	160-560	4	4	2
4B	160-560	1	5[1]	2
3C	160-560	5	5	2
CS	160-560	2	5[2]	
4C	160-560	2	Hi[3]	2
3C	150-480	Lo	7[4]	1
DS	450-1550	Lo	Lo	3
4D	160-560	5	5	2

*Parts Numbers

1. w P/N 1268C14G04
2. w P/N 454D676G18 (Original P/N)
3. w P/N FB31550MRL

Plant Work Orders to Change Setpoints

1. PWO #5506
2. PWO #4189
3. PWO #5504
4. PWO #4857

PWO numbers 5506, 4189, 5504 and 4857 were issued to adjust the setpoints for breakers on the 4B, CS, 4C and 3D inverters, respectively; however, adjustment of the breakers was accomplished prior to vendor concurrence, and issuance of an NCR requesting engineering to provide setpoints for the instantaneous trip elements on the inverter input breakers. In addition, subsequent issuance of the NCR failed to identify all types of breakers installed in the inverters.

The licensee has issued a request for an engineering evaluation and coordination study to determine the DC feedbreaker and inverter input breaker trip setpoint settings. The licensee committed to complete this study and to address breaker settings for the replacement inverters. Completion of the engineering evaluation and specification of breaker trip setpoint settings will be an inspector followup item (250, 251/85-22-11).

10 CFR 50, Appendix B, Criterion II, requires that design control measures shall assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled. Contrary to the above, inverter input breaker instantaneous trip settings were not specified and included in design documents prior to installation, and when identified, changes to the setpoints were initiated prior to issuance of a complete and accurate NCR.

In that the violation of 10 CFR 50, Appendix B, Criterion II, detailed above meets the criteria for licensee self identification contained in

10 CFR 2, Appendix C, paragraph V, a notice of violation will not be issued.

PCM 80-31 approved the use of replacement breaker for the inverters (P/N 1250C29G04) due to the manufacture no longer supplying the original breaker. Review of the inverter breaker replacements accomplished under this PCM indicates that a different breaker (P/N 1268C14G04) was installed on inverters 3A, AS, 4A and 3C. Until the licensee can provide documentation justifying the installation of other than the approved breaker specified in PCM 80-31, this item will remain unresolved (250, 251/85-22-12).

d. Design Modifications

The loss of a 120 volt bus results in an ex-core detector channel failing low and initiation of automatic turbine runback logic. The automatic turbine runback feature is designed to provide protective action in the event of a dropped RCCA or dropped rod bank. A dropped RCCA or dropped bank is detected by either a rod-on-bottom signal or by a decrease in neutron flux as detected by the power range excore instrumentation. During a rod bank or single rod drop event, a turbine runback to 70 percent of full power occurs when either a rod-on-bottom signal or a negative flux rate signal from one of the excore detector channels is received.

Westinghouse provided Florida Power and Light with a safety evaluation for a modification to the turbine runback logic which concluded that the deletion of the NIS (flux rate) input to the initiating logic for turbine runback was acceptable. Modification PCM 83-88/89 removed the flux rate input from the turbine runback logic via a switch. Under normal operations, the flux rate input was removed from the turbine runback logic, and only the rod-on-bottom signal was utilized. The modification performed under PCM 83-88/89 did not consider the single failure criterion. Disconnecting the NIS signal (via the switch) effectively defeated the turbine governor control system as a means of running back the turbine, thus removing diversity from the turbine runback protection system which was inconsistent with Chapter 14 of the FSAR. Based on a Westinghouse recommendation, the NIS input signal to the turbine runback logic was reinstated on Units 3 and 4. With the NIS input signal to the turbine runback logic reinstated, Units 3 and 4 were again susceptible to turbine runbacks and adverse transients due to a loss of a 120 volt vital bus.

During the recent Unit 3 outage PCM 84-210 was completed to provide and acceptable method for deleting the NIS input from the turbine runback logic and diversity to the RPI signals. The turbine runback initiating logic was modified such that an RPI or an NIS flux rate signal initiates both turbine governor and load limit runbacks simultaneously. The original plant design had RPI signals initiating a load limit runback only, while NIS signals initiate both. Installation of a turbine runback selector switch permits the operators to choose the

input(s) desired for the turbine runback initiating logic. The selector switch is a four position, key locked, Westinghouse type W-2 switch.

The four positions of the switch are as follows:

Position	Function
RPI	Selects RPI signals only for the turbine runback initiating logic (i.e., turbine governor and load limit control systems)
NIS	Selects NIS signals only for the turbine runback initiating logic (i.e., turbine governor and load limit control systems)
RPI or NIS	Selects both NIS and RPI signals (i.e., turbine governor and load limit control systems)
OFF	Disables the NIS and RPI signals for the turbine runback initiating logic

The normal operating position for the selector switch is RPI. This significantly reduces the probability of a turbine runback on the loss of a 120 volt vital bus.

The modification will be installed on Unit 4 during the next refueling outage scheduled for January 1986. Due to continued problems with the static inverters, an interim modification (PCM/85-103) has been installed on Unit 4 to reduce the probability of turbine runback on a loss of a 120 volt vital bus. The modification changed the turbine runback logic to two out of four NIS channels for initiation; therefore, a loss of one NIS channel will not initiate a turbine runback.

e. Inverter Replacement Schedule

The licensee has established a tentative schedule for replacement of the twelve static inverters which supply the 120 volt vital AC buses. Major milestones in this schedule include the following:

(1) Complete installation and testing of the CVTs for all twelve inverters by July 12, 1985

(2) Install one new inverter by the end of July 1985

(3) Complete the installation of four new inverters, one for each set of vital AC buses, by October 1985. This will provide added reliability for these vital buses and for the operation of Units 3 and 4

(4) Complete installation and testing of all twelve new inverters by February 4, 1986

Due to a forced outage of Unit 3 during this inspection, the licensee opted to accelerate this schedule two weeks by utilizing a two shift operation during the outage. This should facilitate completing the installation and testing of the CVTs for Unit 3, and possibly the installation of one new inverter prior to returning Unit 3 to operation. After the installation and "burn-in" testing of the first inverter, the licensee intends to install four at a time unless problems are encountered. This schedule could also be accelerated further if no problems are encountered, and the thirty day "burn-in" time for each inverter can be reduced.

These new inverters are manufactured by a different company and contain improved electronic filtering circuits and PC card connectors. This should make the inverter less prone to trip on system fluctuations and grounds and provide a more reliable source of power to the vital AC buses. In addition, the adding of an auto-transfer to a standby CVT power source in less than a cycle should help prevent a loss of these vital buses and a reactor trip should an inverter be lost.