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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

TURKEY POINT ALLEGATION TEAM INSPECTION

Report Nos.: 50-250/91-45 and 50-251/91-45

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

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Inspector: Kerry D. Landis 12-30-91
Kerry D. Landis, Team Leader Date Signed

Accompanying Personnel: M. Hunt, Reactor Inspector
L. Mellen, Reactor Inspector
M. Thomas, Reactor Inspector
P. Fillion, Reactor Inspector
G. Schnebli, Resident Inspector
W. Tobin, Security Inspector
O. DeMiranda, Senior Allegation Coordinator
R. Brady, NRR Allegation Program Manager

Contributing Personnel: R. Butcher, Senior Resident Inspector
P. Taylor, Reactor Inspector
R. Chou, Reactor Inspector
P. Burnett, Reactor Inspector

Approved by: Marvin V. Sinkule 1/2/92
M. V. Sinkule, Chief Date Signed
Reactor Projects Branch 2
Division of Reactor Projects

DESIGNATED ORIGINAL

Certified By Kerry Landis BW
1/23/92

EXECUTIVE SUMMARY

1. OBJECTIVE: The objective of this team inspection was to determine if there existed any unsafe engineering practices or operating conditions associated with thirteen allegations made by a former FPL employee or if personnel practices resulted in a chilling effect with regard to pursuing a safety issue. Some of the allegations involved discrimination in the form of threats, coercion, harassment, and negative evaluations for which the US Department of Labor is evaluating the specific case of employee discrimination. The NRC will monitor the Department of Labor activities regarding this case for potential enforcement. The team did attempt to determine, in the general sense, if there was an atmosphere which prohibited or discouraged engineers from pursuing nuclear safety concerns. In each of the thirteen allegations, the objective was to determine if it was:

SUBSTANTIATED -	The allegation has substance and is considered for the most part true.
PARTIALLY SUBSTANTIATED -	The allegation has some substance and is considered partially true.
NOT SUBSTANTIATED -	No substance could be found to support the allegation.

If the allegation was either substantiated or partially substantiated, a determination of safety significance was made.

Additionally, with respect to the technical areas identified, the team evaluated whether there was a condition adverse to safety by inspecting the end products such as safety evaluations, plant change modification packages, and setpoint calculations to determine if they were adequate. A performance-based inspection which includes inspecting the end products should find sufficient end products which are inadequate in order to substantiate or partially substantiate the allegation.

2. SCOPE: The team inspection activities included engineering staff interviews and end product inspection at both the FPL Juno Beach Offices and at the Turkey Point Nuclear Plant. The scope of the inspection was limited to the specifics of each allegation and, if justified, expanded to a programmatic inspection.

3. CONCLUSION: Inspection of the thirteen allegations resulted in the following:

11 - NOT SUBSTANTIATED
1 - NOT INSPECTED (EEOC JURISDICTION)
1 - PARTIALLY SUBSTANTIATED

The following allegation was determined to be partially substantiated:

Management's decision to postpone, due to budgeting or other constraints, important modifications such as the correction of the Power Mismatch Circuits

Each modification that was postponed during the dual-unit outage at TPNP was determined to have no impact on plant safety.

There was no evidence found to substantiate the allegations of an overall atmosphere of intimidation, threats, coercion, harassment, or negative evaluations to limit the pursuit of safety issues. No unresolved safety issues were identified by the team.

4. ENFORCEMENT: Within the scope of this inspection three violations were identified.

50-250,251/91-45-01, Non-Cited Violation. Failure to implement adequate design integration (paragraph 4).

Based on the review of the licensee's design integration program, the inspectors determined that the licensee had an adequate program for ensuring that applicable information is available to FPL engineers involved in performing design integration for appropriate design activities. The team concluded that, while there was an instance noted where design integration was not adequately performed in accordance with program requirements, the instance described in paragraph 4 did not constitute a programmatic breakdown of the design integration process. Consequently, the allegation that design integration was almost non-existent and fundamentally flawed was not be substantiated.

50-250,251/91-45-02, Violation. Failure to maintain design control of the Eagle 21 system (paragraph 13).

50-250,251/91-45-03, Violation. Failure to use correct Delta T Subzero for calculation of the Overtemperature Delta T and Overpower Delta T setpoints (paragraph 13).

The team concluded that, while there are two cited violations, which were identified and described in paragraph 13, these violations did not constitute a programmatic breakdown in design and configuration control. Consequently, alleged "grave deficiencies" in plant configuration were not substantiated.

5. FOLLOWUP: The effort to provide a single consolidated Instrument Setpoint Document which contains all setpoints, including design bases, both safety and non-safety related, is considered by the NRC to be an important enhancement and will be inspected at a future date.

50-250,251/91-45-04, Inspector Followup Item, Create a single Instrument Setpoint Document, including design bases (paragraph 10).

FPL, as part of evaluating a 10 CFR Part 21 report, has completed 65 percent and was in the process of performing a study of 100 percent of circuits that contain devices or wiring in the miscellaneous relay racks. No safety problems, with respect to keeping MRR annunciator circuit relays separate from the RPS power supply, have been identified to date. The study is scheduled to be completed by March 31, 1992. NRC will review the final results of this study.

50-250,251/91-45-05, MRR annunciator circuit relays separation from RPS power supply (paragraph 12).

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ALLEGATION TEAM INSPECTION RESULTS

1. ENGINEERS DISCOURAGED FROM PURSUING SAFETY CONCERNS:

The statement of the concern was as follows:

FPL Management has engaged in threats, coercive behavior, harassment, negative and untruthful engineering personnel evaluations, withholding of necessary training, and assignment of work unrelated to the engineer's discipline while removing all significant assignments related to his discipline to discourage engineers from the pursuit of tasks that such engineers consider critical to Nuclear Safety and prudent plant operation.

DISCUSSION: The objective of this team inspection was to determine if there existed any unsafe engineering practices or operating conditions or if personnel practices resulted in a chilling effect with regard to pursuing a safety issue. This allegation involved discrimination in the form of threats, coercion, harassment, and negative evaluations for which the US Department of Labor is evaluating the specific case of employee discrimination. The NRC will monitor the Department of Labor activities regarding this case for potential enforcement. The team attempted to determine, in the general sense, if there was an atmosphere which prohibited or discouraged engineers from pursuing nuclear safety concerns.

The inspectors conducted formal interviews of all of the following non-supervisory engineers which were available at the time of the interviews: FPL Juno Beach Engineering staff, the TPNP Production Engineering Group (PEG), and the Outside Services Management staff. A total of 43 engineers were interviewed to ascertain if engineers were being prohibited or discouraged from pursuing safety concerns. The interviews were conducted in the following manner in order to foster open and candid discussions: two NRC inspectors conducted one-on-one interviews concurrently in separate and private rooms, thirty minutes each, in the same location each day, during normal working hours, asking each the same set of questions, with no subsequent followup discussions during the team inspection. The questions were focused to allow comparison and correlation of the interview results and to prompt discussion of facts which would assist in determining the validity of the allegations. In addition, approximately 20 informal interviews were conducted of the engineering supervisory staff as part of the inspection into each of the allegations.

On October 31, the team leader was notified that an internal memorandum from the FPL Law Department to the Director, Nuclear

Engineering, dated October 25, 1991, had urged FPL employees to not discuss the matter of the legal proceedings between FPL and the alleger in the interest of fairness to both sides. Another memorandum dated October 30, 1991, corrected the guidance of the October 25 memorandum by stating that non-supervisory employees should feel free to cooperate and talk about their knowledge in the subject legal proceedings if they so desired. Supervisory employees were advised that they should not speak with anyone making a claim against FPL. The alleger raised the concern that these memoranda may have caused FPL employees to not feel free to discuss any of the allegations openly with the NRC. The team evaluated this concern and concluded, that the discussions conducted with over 60 engineers, 43 of whom were non-supervisory, were open and candid. There were some comments, the sum of which, in the judgement of the team, indicated some anxiety over the pending FPL reorganization, but did not indicate a lack of freedom to discuss the concerns addressed in this report with the NRC.

Additionally, with respect to the technical areas identified, the team evaluated whether there was a condition adverse to safety by inspecting the end products such as safety evaluations, plant change modification packages, and setpoint calculations to determine if they were adequate. If interviews did not substantiate that engineers were discouraged from pursuing safety concerns, then a performance-based inspection, which includes inspecting the end products, should find sufficient end products which are inadequate in order to substantiate or partially substantiate the allegation.

1.a The following amplification of the above concern was provided:

<u>Plant maintenance instructions affecting RPS/ESFAS to proceed under certain restricted modes (Safety evaluation JPN-91-0094) was revised without subsequent review by the alleger. Violation of among others, QI 3.2. Westinghouse was directed to keep him isolated from project (PC/Ms 90-508 and 90-509).</u>

<u>Discussion</u>: The FPL safety evaluation which allowed the procedures to be revised and implemented under certain restricted modes was JPN-PTN-SEIJ-91-008. The safety evaluation was transmitted to Turkey Point site by letter JPN-91-0094. The inspectors reviewed the safety evaluation which allowed plant maintenance instructions to be revised in accordance with applicable marked-up versions of the procedures. The maintenance instructions were marked-up by the NSSS based on the proposed license amendment which had been previously submitted to the NRC. The inspectors also reviewed quality instruction QI 3.2, Design and Safety Analyses.

During reviews of the safety evaluation, selected plant maintenance instructions, and QI 3.2, the inspectors found that the revisions

to the plant maintenance instructions did not affect the conclusions of the safety evaluation. Since the safety evaluation was not impacted by the revised maintenance instructions, QI 3.2 was not violated when the maintenance instructions were not sent back to the safety evaluation preparer prior to implementation. In addition, the safety evaluation did not require that the maintenance instructions be routed back through the safety evaluation preparer prior to revision and implementation.

The inspectors determined that the maintenance instructions were reviewed and approved at the Turkey Point site in accordance with plant administrative controls. These controls included, but were not limited to, a safety review by the Technical Department; review and approval by the responsible system engineer, as appropriate; review and approval by the I & C Department head; and review and approval by the Plant Nuclear Safety Committee.

The inspectors reviewed selected maintenance instructions that were revised, and verified that the technical changes included in the marked-up instructions were incorporated into the revised maintenance instructions. The inspectors also verified that other selected maintenance instructions, which were revised to incorporate the changes from the marked-up versions submitted by the NSSS, were reviewed and approved in accordance with applicable TPNP administrative controls.

Conclusion: The inspectors concluded that the revisions to the maintenance instructions did not violate QI 3.2 nor any requirements of the safety evaluation.

1.b The following amplification of the above concern was provided:

> The alleger received a negative evaluation as a result of his efforts to resolve problems with pressurizer pressure protection transmitters. His work was exhaustive and met with opposition, conflict and friction. Transmitters were replaced. (PC/M packages 90-528 & 90-529)

Discussion: The inspectors determined as background to this concern (pressurizer low pressure transmitter replacement), that the Pressurizer Pressure Low Safety Injection actuation function was previously performed using a Rosemount 1153 Series D pressure transmitter. The Rosemount transmitters were installed in 1983 and 1984 and replaced obsolete Fisher-Porter transmitters. The setpoint for this instrument loop was provided by the NSSS vendor as part of the original scope of supply.

As a result of the design basis reconstitution effort, the licensee determined that certain plant setpoints should be recalculated. A

program was undertaken to recreate the bases for these setpoints in accordance with currently accepted methods, standards and test information.

The NSSS vendor recalculated the Reactor Protection System and Engineered Safety Features Actuation System setpoints in accordance with the previously accepted Westinghouse "Five Column" Setpoint Calculation Methodology. While applying the new setpoint calculation methodology to the Pressurizer Pressure Low Safety Injection instrument loop, the NSSS vendor identified that available test information, such as the lack of harsh environment qualification which resulted in greater response uncertainties, may result in spurious Safety Injection actuations. As a result, the vendor recommended that the 1153 Series D transmitters be replaced with transmitters which had lower documented errors under adverse environmental conditions.

The licensee investigated scope of replacing the 1153 series D transmitters with Rosemount 1154 Series H transmitters. The vendor calculated setpoint was conservative. The published Rosemount error specifications provide two sets of possible Environmental Allowance terms depending on the type of environment in which the transmitters were expected to operate (mild or harsh). Because the transmitters were within the scope of 10 CFR 50.49, Environmental Qualification of Electrical Equipment, the vendor concluded that the more restrictive environmental allowance terms (±4.5% Upper Range Limit + 3.5% span for temperature uncertainty and ±6% for radiation uncertainty) were applicable. These environmental allowance terms correspond to the worst case errors that Rosemount experienced during Environmental Qualification testing at temperatures, pressures and radiation levels (420 degrees Fahrenheit, 85 psig and 52 MegaRad), each of which significantly exceed the expected operating conditions at TPNP.

The licensee's investigations involved consideration of using realistic environmental allowance terms: ±(0.75% Upper Range Limit + 0.5% span per 100 degrees Fahrenheit) for temperature uncertainty. This investigation involved quantifying the environmental conditions during design basis events at the time Safety Injection actuation was expected to occur. Time to actuate ranged from about 1 second for the maximum hypothetical pipe break to about 30 seconds for the 3 inch small break analysis. Since the function of this trip was to protect the core design temperature limits, no abnormal radiation was expected at Safety Injection actuation. The vendor provided preliminary information on expected containment temperatures that indicated temperatures would not noticeably change in one second during the maximum hypothetical Design Basis Event. Data for two, three, and six inch break sizes indicated that the maximum expected temperature increase was approximately 20 degrees Fahrenheit for the first 30 seconds in a three inch break loss of coolant accident.

Preliminary information indicated that the time to actuate/ containment temperature evaluation could be used to justify the lower environmental allowance term. The setpoint acceptability using this lower environmental allowance term was evaluated with respect to how it would increase the probability of spurious safety injections and was found to be acceptable.

The relative merits of replacing the 1153 Series D transmitters with 1154 Series H were weighed against continued use of the 1153 Series D transmitters. Two dominant factors led to the decision to replace the transmitters. First, the vendor requested that FPL document the time to actuate/containment temperature evaluation and provide specific direction on what values for transmitter error to use for the calculation. The vendor took this position because use of the "time to trip" argument for a 10 CFR 50.49 component was inconsistent with previous work they had performed on other projects. Second, Rosemount had limited test data for temperature changes within the range of interest and could not support the target 95%-95% probability and confidence level for use of the lower environmental allowance term.

The licensee concluded that if the new calculation methods were applied to the existing setpoint (1723 psi), that loop errors could cause actuation to occur below the calibrated span (1700-2500 psi) of the pressurizer pressure transmitter. The basis for the existing setpoint was not recoverable, but appeared to be consistent with the level of knowledge and test information available in the late 1960's when the setpoint was originally established. The licensee did not consider it necessary to justify the existing setpoints using contemporary methodologies. However, this particular setpoint did receive further evaluation because it was unique in that it was close to the low end of the calibrated range.

Based on the channel uncertainty of 7.92% or 63.4 psi, the actuation setpoint could potentially be reached at 1723 - 63.4 = 1660 psi. This value is approximately 2% below the calibrated span. Since the comparator was set to trip on a signal slightly above 4 Milliamp, it was logical to conclude that on falling pressure, actuation would occur whether or not the process was outside the calibrated pressure range. An additional error of 1% applied to the channel uncertainty corresponds to 71.4 psi and an actuation point of 1652 psi. Rosemount provided information which supported the conclusion that actuation would occur by this point. The licensee concluded that this provided reasonable assurance that Safety Injection actuation would occur before the assumed 1600 psi safety analysis limit would be reached. Safety Injection was also actuated from the independent containment pressure instrument loops providing additional assurance of proper Engineered Safety Features Actuation System operation.

Conclusion: The licensee gathered all pertinent information for options in order to justify the high cost associated with this modification. The licensee made the conservative decision to replace the transmitters. The inspectors verified information provided by the licensee and concluded that, while an unsafe condition did not exist with the previous Rosemount transmitters, the licensee had taken a prudent course of action relative to their evaluation in order to provide transmitters qualified for a more harsh environment and more conservative setpoints. It could not be substantiated that a negative evaluation resulted from trying to solve a problem with the previous Rosemount transmitter. During the engineering staff interviews, there were no concerns identified that performance appraisals were adversely affected for pursuing safety concerns.

1.c The following amplification of the above concern was provided:

Emergency Response Data Acquisition Display System (ERDADS) Isolation project modification was delayed until a demonstration was conducted to show the existing problem (improper electrical isolation) with ERDADS.

Discussion: The licensee had experienced problems with the interface of the ERDADS and the process loops in that certain loops caused the control room indicators to read inaccurately when connected with the ERDADS. Temporary System Alteration (TSA) 4-89-95-20 and 4-89-95-21 were incorporated which corrected approximately 14 loops by electrically relocating the control modules in the instrument loops to minimize the current loss and thereby reduce the effect on the control room indicators. It should be noted that the control room indicators were electrically isolated from the control functions of the reactor control system so that there was never a problem with the reactor control system. NCR 89-0709 was written as the result of these problems.

The inspectors reviewed NCR 89-0709 which identified a problem with excessive loading at the high signal end caused by interference from the SPDS circuitry. The evaluation which the licensee performed resulted in the installation of an isolation system which provided both digital and analog isolation from the process loops and imposed no load on the instrumentation loops. This modification also removed TSA 3-89-95-28 and -29 which had been issued for twelve non-isolated inputs to the SPDS. The isolation system was in place and operating and plant personnel advised that there have been no difficulties experienced.

Conclusion: There was some initial resistance to performing this modification until the problem was understood. Once the significance of the effects of the poor ERDADS isolation was demonstrated to engineering, a TSA was implemented and the permanent modification was completed during the dual unit outage. There was no indication that harassment was used to prevent or delay this project.

1.d The following amplification of the above concern was provided:

Reactor Protection System/Engineered Safety Features Actuation System implementation of setpoint methodology is example of Item 1. (No written details provided.)

Discussion: The inspectors reviewed Westinghouse WCAP-12201, Bases Document for Westinghouse Setpoint Methodology for Protection Systems, Revision 1, and WCAP-12745, Westinghouse Setpoint Methodology For Protection Systems - Turkey Point Units 3 and 4 - Florida Power and Light Company, Revision 0. These documents provided the basis for calculation of instrument uncertainty and setpoints for Reactor Protection System/Engineered Safety Features Actuation System. The documents included acceptable calculational methodology. Westinghouse performed the RPS/ESFAS calculations for TPNP and does these same calculations for most Westinghouse design plants.

Conclusion: There were no problems noted with these calculations which were inspected and found to be acceptable. FPL management practices in the implementation of the RPS/ESFAS setpoint methodology, which would discourage engineers from the pursuit of safety concerns, was not substantiated.

CONCLUSION: ALLEGATION 1 - NOT SUBSTANTIATED

Open and candid discussions were conducted with over 60 engineers, 43 of whom were non-supervisory. There were some comments, the sum of which, in the judgement of the team, did not indicate management's engaging in threats, coercion, harassment, or intimidation. The inspectors concluded that this allegation was not substantiated because evidence was not found that engineers were prohibited or discouraged from pursuing safety concerns. Additionally, the evaluated end products (i.e. safety evaluations, PC/Ms, and setpoint calculations) were determined to be adequate.

2. INTIMIDATED TO CHANGE VCT SETPOINT CALCULATION

The statement of the concern was as follows:

FPL Management have attempted to intimidate me into changing the conclusions of an Engineering Calculation regarding Setpoints and Uncertainties, PTN-BFJI-91-005 for Volume Control Tank Transmitter Replacement Package, PC/M's 91-037 and 91-038. FPL intimidation to change conclusions of engineering calculation. Assumptions changed to support desired conclusions. Adverse effect on performance appraisal. Threatening an engineer to alter the content or results of a calculation. Applying reprisals for failure to comply.

DISCUSSION: The inspectors discussed the methods the licensee used to resolve differences when independent calculations arrived at disparate results. The licensee described their approach to the resolution of technical differences that occur during the setpoint verification or review process as follows:

Obtaining different final results when performing two independent and technically correct analyses is a common occurrence when determining instrument setpoints. Various available methods for generating instrument setpoints is generally the root cause of differing results.

Typically, the difference occurs when the prepared calculation is undergoing the independent verification process. The method judged appropriate by the preparing engineer to determine or combine the specific instrument uncertainties or determine the final nominal setpoint may differ from the methods judged to be applicable by the verifying engineer.

Due to the straight forward nature of FPL and industry setpoint guidance along with the availability of in-house setpoint expertise, it is the very rare instance when the differing methods cannot be resolved into a calculation which is technically acceptable to both the preparer and verifier. The vast majority of differences are resolved without the need for a technical management decision.

The inspectors independently reviewed the licensee's methodology for the resolution of disparate setpoint calculation resolution and concurred that the licensee demonstrated an understanding of the causes of most setpoint calculational discrepancies and that their methodology for resolving these discrepancies was adequate.

Chemical and Volume Control System Calculations: The inspectors reviewed the FPL Engineering calculation PTN-BFJI-91-005 which was performed to support PC/M No. 91-037 and 91-038, regarding the replacement of the VCT level control and alarm switches with

electronic transmitters. The modification involved the removal of the level switches used for alarm and control and the installation of two differential pressure transmitters, instrument manifolds and sensing lines in the area of the VCT. The corresponding instrument loops contained the necessary process rack mounted instrumentation to perform the control and indication functions. Only one of the loops provides an alarm function. The VCT level transmitters are not required for the CVCS to perform its active safety functions related to reactivity control; consequently, they are not safety related transmitters. The calculation contained appropriate assumptions which were in line with standard acceptable methodology.

The methodology used for the calculations was an adaptation, for non-protective setpoints, of the guidelines and structures listed below:

Plant Engineering Group (PEG), Training Manual on Turkey Point Setpoint Methodology, Revision 0, dated February 1991

WCAP 12201, Bases Document for Westinghouse Setpoint Methodology for Protection Systems

WCAP 12745, Westinghouse Setpoint Methodology For Protection Systems - Turkey Point Units 3 and 4 - Florida Power and Light Company

The revised engineering VCT calculation was performed in accordance with the applicable portions of WCAP-12201 and WCAP 12745 methodology, with modifications for non-safety related, non-protection system, control functions.

Calculation No. PTN-BFJI-91-005, Setpoint Calculation for VCT Level Transmitters Loop, Revision 0 which was approved May 21, 1991, was reviewed to determine the origin and acceptability of the assumptions used in the calculations. Installation drawings were reviewed to verify the location of the VCT instrument taps as they relate to the instrument calibration span and the instrument range selection. The calculation considered the various process measurement uncertainties such as the variation of the fluid specific gravity due to boron concentration, transmitter ambient temperature effect, rack ambient temperature effect, sensor errors, calibration accuracy and drift, and sensor measurement and test equipment accuracies.

The alleger was asked to perform calculations, in support of a PC/M which replaced the existing transmitters with more accurate transmitters, consequently hardware modifications should not have been required (i.e. transmitter relocation). A disagreement occurred over the calculation results, while at the same time the calculation was becoming critical path for the VCT transmitter replacement PC/M. When agreement could not be reached, the

supervisor removed the alleger from the project and performed the calculation.

Since both calculations used the same standard setpoint methodology discussed above, and there were many differences in both calculations (other than assumptions), it could not be substantiated that the supervisor copied the alleger's calculation and changed the assumptions to get the desired results.

The FPL final VCT calculation resulted in a change to a setpoint which was required to remove the possibility of demand for both letdown and makeup at the same time. This setpoint change was not identified in the alleger's calculation.

The inspectors independently reviewed the alleger's draft and the FPL final calculations for the VCT level transmitter loop. The inspectors concurred with the FPL calculation results that indicated a change in the control setpoint in question was not necessary. The alleger's calculation contained unnecessary conservatisms. The safety related portions of the calculation were not in question and yielded the same results in both calculations.

The only significant problem that was identified in either of the calculations was identified in the FPL manager's verified calculation. As a result of this calculation there was a change in VCT LC-112A setpoint from 37% to 40%. This change was to prevent overlap between the worst case drift for the makeup and the letdown. With the worst case drift there could have been a simultaneous demand for both VCT makeup and letdown. The setpoint has been changed and this potential problem has been corrected.

The approved calculation was found to be technically adequate in that the setpoints values were consistent with the proper operation of the CVCS as described in technical system descriptions and licensing documents. The inspectors reviewed the current setpoints for the VCT and determined that the operating setpoints and the safety-related setpoints were appropriate. No other setpoint discrepancies were identified.

The issued calculation was correct and the assumptions were accurate. Evidence was not found to substantiate that any portion of the final calculation had been falsified. Therefore, it could not be substantiated that the supervisor was attempting to intimidate the alleger to change or falsify the VCT setpoint calculation.

FPL had a consultant review the FPL approved VCT calculation and it was found to be acceptable.

CONCLUSION: ALLEGATION 2 - NOT SUBSTANTIATED.

The FPL approved VCT calculation was determined to be adequate. The inspectors concurred with the FPL calculation results that indicated a change in the control setpoint in question was not necessary. The alleger's calculation contained unnecessary conservatisms for non-safety related applications. The FPL final VCT calculation resulted in a change to another setpoint which was required to remove the possibility of demand for both letdown and makeup at the same time. This setpoint change was not identified in the alleger's calculation. The safety related portions of the calculation were not in question and yielded the same results in both calculations. The issued VCT setpoint documents are conservative and demonstrate an appropriate safety perspective. Evidence was not found to substantiate that any portion of the final calculation had been falsified. Therefore, it could not be substantiated that the supervisor was attempting to intimidate the alleger to change or falsify the VCT setpoint calculation.

3. PERFORMANCE EVALUATIONS PUNITIVE WHEN SAFETY CONCERNS RAISED:

The statement of the concern was as follows:

Performance evaluations of engineers tasked with nuclear safety related work have been done exclusively against criteria of budgeting and scheduling with punitive actions for concern by the engineer with technical and safety impact of work and projects.

DISCUSSION: Most non-supervisory engineers interviewed stated that their performance is based upon six different criteria of which budgeting and scheduling are a part. The six factors evaluated are:

1. TECHNICAL/JOB KNOWLEDGE
2. INITIATIVE
3. JUDGEMENT/PROBLEM ANALYSIS
4. ORGANIZATION/PLANNING
5. DEPENDABILITY
6. COOPERATION

While greater emphasis is placed on budget and schedule related criteria for project engineers who are assigned to the OSM group, the interviews of 43 engineers did not indicate an inappropriate emphasis on budget and schedule considerations.

The candid comments, while supporting that there is variation among supervisors with respect to their emphasis on budget and schedule related criteria, did not support that these factors were used in a punitive manner to suppress safety concerns.

CONCLUSION: ALLEGATION 3 - NOT SUBSTANTIATED

This allegation was not substantiated in that budget and scheduling are neither the exclusive criteria nor the overriding factors used on performance appraisals.

4. DESIGN INTEGRATION HAS BECOME ALMOST NON-EXISTENT:

The statement of the concern was as follows:

Design integration has become almost non-existent with the restructuring of the Engineering Department. No valid means exists to make cognizant engineers aware of modifications that affect their work. Design integration is fundamentally flawed.

The following amplification of the above concern was provided:

Review of FPL response to NRC questions of 6/6/91 on Technical Specification submittals L-90-417 and L-91-098 concerning Reactor Protection System/Engineered Safety Features Actuation System setpoint Tech Spec: Licensing engineers acknowledge at CNRB meeting of 6/28/91 they are unqualified to respond to NRC questions; failure to review response w/knowledgeable engineers within the department; assigned to Westinghouse responsibility for response assuring NRC of FPL confidence in Westinghouse work; and on a previous occasion, Westinghouse response (L-91-098) to a set of NRC questions while in midst of FPL review/signature process, but after review from licensing, were brought to alleger by a co-worker who noticed several errors.

DISCUSSION: Design Integration ensures that the cognizant design organization is able to identify activities which may affect (or be affected by) other current design activities. The licensee has implemented procedure QI 3.1-7, Design Integration, which provides requirements for design integration activities using available design integration tools. The procedure applies to design integration activities performed by JPN and its contractors, as the activities relate to the preparation of all design outputs and the control of in-process design. Design integration tools included the following:

DCTS is a database which lists drawings affected by issued PC/Ms, CRNs, and DCRs. The DCTS will also list anticipated affected drawings for in-process engineering packages.

PC/M Index lists all PC/Ms for which a number has been assigned. Additional PC/M related information is typically included in the index such as PC/M title, description,

affected systems, etc. This index allows identification of PC/Ms potentially affecting the same system or component.

Calculation Index lists JPN and contractor calculations. This index allows the identification of related calculations which may provide the basis or change the basis for a design. This information has not been fully input into the data base.

Engineering Evaluation Index lists JPN and contractor engineering evaluations. The engineering evaluations are still being maintained manually until they all have been input into the data base.

The inspectors noted that procedure QI 3.1-7 was first issued in May 1991. During discussions with licensee personnel, it was stated that various design integration tools have been available to JPN personnel for a number of years. The requirements for design integration were previously addressed in other QIs such as QI 3.1, Design Control and QI 3.1-3, Engineering Package. The Configuration Management Manager is responsible for maintaining the design integration tools.

The inspectors reviewed selected PC/Ms and verified that appropriate design integration tools had been reviewed for each of the PC/Ms and evidence of the review was documented within each PC/M package. In addition to reviewing the PC/Ms, the inspectors held discussions with JPN personnel involved in PC/M development who demonstrated how the PC/M index and the DCTS are used for design integration.

During further review of the design integration process, the inspectors noted that it was not clear (from reviewing the selected PC/Ms or the QIs) at what point in the development of design outputs should design integration be performed. The inspectors discussed this item with JPN personnel who stated that there had been a recent instance where the design integration process had not been properly implemented. The instance where design integration was not adequately performed involved the licensee's PLA submittal for the RPS/ESFAS setpoints and the issuance of PC/Ms 90-508 and 90-509, Implementation of Setpoint Methodology. The instance of inadequate design integration was identified by the licensee following receipt of an NRC letter dated June 6, 1991, which was a RAI concerning the RPS setpoints. The licensee documented these discrepancies in problem report JB-91-06, Errors in Technical Specification Submittal to NRC on RPS/ESFAS Setpoint Methodology, dated September 10, 1991.

The NRC asked if the assumptions and inputs used in developing the setpoint study had been reverified. While preparing FPL's response to the RAI, JPN determined that neither FPL nor Westinghouse reverified the validity of the original inputs used in the performance of the setpoint calculations. During reverification of

the inputs, Westinghouse found that the setpoint inputs for two functions (Containment Pressure-High and High-High) had changed from those originally used in the 1988 setpoint calculations. The changes were caused by the implementation of two DEEPs which replaced the existing containment pressure switches with switches having a different span. The span changes resulted in changes to the Technical Specifications allowable values for the two functions. The actual setpoint did not change.

During further review of the design integration process, the licensee determined that the NSSS vendor failed to provide adequate design integration prior to implementation of the setpoint PC/Ms 90-508 and 90-509. JPN and Westinghouse reaccomplished the entire design integration process for the PC/Ms. As a result of that effort, two additional functions used as inputs to the original submittal were determined to be incorrect. One input involved a typographical error in the instrument index and the calibration procedure (used as original inputs) resulted in an incorrect model number being used for the turbine trip auto stop oil pressure switch. This resulted in an incorrect span for the device being used in the original input. The other input involved a DEEP performed in 1989 which changed out the reactor coolant pump underfrequency relays with a model having a span different from that originally assumed in the setpoint methodology. The licensee documented these errors in their response to the RAI dated July 8, 1991.

The licensee evaluated all of these additional changes to the Technical Specifications and determined that the changes did not affect the "no significant hazards consideration" determination. The licensee's evaluation results were confirmed by the NRC via an SER dated August 26, 1991, which accompanied the approved license amendments and Technical Specification changes.

The inspectors informed the licensee that QI 3.1, QI 3.1-3, and QI 3.1-7 require design integration for all design outputs and the control of in-process design. Contrary to the above, inadequate design integration was performed for the PLA submittal for RPS/ESFAS setpoints and PC/Ms 90-508 and 90-509. The design integration reviews failed to identify that three DEEPs were implemented which affected the inputs used in performing the setpoint calculations.

This failure to follow procedure is not being cited as a violation, because the criteria specified in Section V.G.1 of the Enforcement Policy were satisfied. This item will be tracked as NCV 50-250,251/91-45-01, Failure to Perform Adequate Design Integration During Implementation of RPS/ESFAS Setpoint Methodology. This item is considered closed.

During further discussions of this item with licensee personnel, the inspectors reviewed Problem Report JB-91-06 which described the

cause for the errors in the Technical Specification submittal to the NRC. The problem report also provided corrective actions which should reduce the probability of the design integration problems reoccurring. These actions included the following:

Design integration training was provided to applicable Westinghouse personnel.

The inputs were reverified by a joint team of Westinghouse and JPN engineers.

Additional written guidance was provided to applicable JPN personnel on the level of discipline review necessary for contracted work. A Technical Alert was issued August 16, 1991 on this subject. In addition, QI 3.11, NRC Submittals, and QI 6.7, Engineering Evaluations, have been revised to require more review and/or approval by the applicable disciplines within JPN.

Input controls are being established by developing a matrix on the bases for the inputs to the setpoint methodology, and incorporating this information in the Westinghouse setpoint calculation. This matrix is scheduled to be completed by the end of 1991.

During review of the concern about licensing engineers not being qualified to respond to NRC questions, the inspectors found that the licensing engineer is not required to be the qualified reviewer for technical adequacy for NRC RAI and submittals. Nuclear Licensing provides the administrative control of NRC submittals. QI 3.11, NRC Submittals, states that the engineering project managers are responsible for approving NRC submittals relating to nuclear engineering, assigning the lead discipline, coordinating schedules and responses, and tracking or completing action items associated with NRC submittals. While it is true that a licensing engineer did acknowledge at the CNRB meeting of June 28, 1991, that he is unqualified to respond to NRC questions, QI 3.11 does not require that level of knowledge.

The OSM project engineer is responsible for determining the level of review. Although the responses were not reviewed by knowledgeable engineers within JPN, the responses were reviewed by a knowledgeable I&C engineer at the TPNP, whom the alleger referred to as being "...highly respected both for his Technical/Professional abilities and Ethical qualities...."

As a result of errors found in the PLA submittal to the NRC (FPL letter L-90-417 dated December 19, 1990), the licensee has revised applicable procedures requiring JPN interdiscipline review of all NRC submittals.

Westinghouse was contracted to provide the PLA and safety evaluation for the RPS setpoint changes. The licensee assigned design authority and design integration responsibility to Westinghouse. The NRC asked, in their RAI dated June 6, 1991, for assurances that the inputs used to develop the new values in the December 1990 Technical Specification submittal (FPL letter L-90-417) were still valid. FPL asked Westinghouse to provide assurances (such as whether the design inputs were reverified prior to submittal of the PLA) of Westinghouse's confidence in the PLA and SER. As discussed previously in this inspection report (paragraph 2), neither FPL nor Westinghouse had reverified the validity of the inputs prior to submittal of the PLA. FPL and Westinghouse jointly reverified the inputs and found the errors that were documented in FPL's July 8, 1991 (FPL letter L-91-186) response to the RAI.

The inspectors considered that, while FPL retains ultimate responsibility for the accuracy of information provided to the NRC, FPL took appropriate actions in requesting Westinghouse to provide assistance in responding to the NRC RAI since Westinghouse had design responsibility for developing the PLA submittal.

Westinghouse initially transmitted the response (L-91-098) to the RAI via facsimile to the licensing engineer at the TPNP. This transmittal did not have errors in the equation. Westinghouse also transmitted the same information to TPNP via computer modem. The information that had been transmitted to TPNP was placed in normal review cycle. This review consisted of a technical review by the various departments prior to review and approval by the PNSC. The review performed by plant licensing personnel is not a review for technical adequacy. The inspectors discussed this item with plant licensing personnel who stated that concurrent with the technical review, licensing personnel reviewed the facsimile transmittal against the modem transmittal and identified the exponent and square root errors in the modem transmittal.

During their normal technical review of the Westinghouse transmittal (modem version), and independent of the Plant Licensing review, the I&C engineer in the plant I&C Maintenance Department also identified the errors in the equations. The inspectors discussed this item with the plant I&C engineer and the I&C Maintenance Supervisor who stated that after the errors were identified, discussions were held with the alleger to verify the validity of the errors. I&C maintenance personnel further stated that they had reviewed each response to an NRC RAI prior to submittal to the NRC.

The inspectors reviewed FPL response to NRC questions of June 6, 1991, on TS submittals L-90-417 and L-91-098 concerning RPS/ESFAS setpoint. The inspectors also reviewed the SER issued on August 26, 1991, which contained a technical review of the RPS/ESFAS setpoint changes. The SER concluded that the setpoints had been

appropriately justified. The NRC has concluded, based on considerations discussed in the SER that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the NRC's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

CONCLUSION: ALLEGATION 4 - NOT SUBSTANTIATED

Based on the review of the licensee's design integration program, the inspectors determined that the licensee had an adequate program for ensuring that applicable information is available to JPN engineers involved in performing design integration for appropriate design activities. The design process was reviewed and found to be sufficiently detailed and functional. Detailed procedures addressing design integration and the required tools are available to engineers for accomplishing the task. The instance concerning the RPS/ESFAS setpoint methodology where design integration was not adequately implemented appeared to be an isolated instance. Other PC/Ms were reviewed with no other design integration problems found.

5. FAILURE TO COMPLY WITH HUMAN FACTORS COMMITMENTS:

The statement of the concern was as follows:

Failure to comply with commitments with respect to Human Factors.

DISCUSSION: NUREG-0737, Task Action Plan I.D.I, Control Room Design Reviews, requires that all licensees conduct a detailed control-room design review to identify and correct design deficiencies. The purpose of the review was to (1) review and evaluate the control room workspace, instrumentation, controls, and other equipment from a human factors engineering point of view that takes into account both system demands and operator capabilities; and (2) to identify, assess, and implement control room design modifications that correct inadequate or unsuitable items.

FPL submitted the TPNP Detailed Control Room Design Review program plan to the NRC on May 20, 1983. The program plan utilized Supplement 1 to NUREG-0737, NUREG-0700, and NUREG-0801 as the bases for the program development. The DCRDR Summary Report was then submitted to the NRC on September 30, 1983. This report identified about 300 Human Engineering Deficiencies per unit and the status of each.

The NRC reviewed these documents and provided FPL with a SER and Technical Evaluation Report of the TPNP DCRDR on February 2, 1984. This report indicated that a pre-implementation audit would be necessary to resolve the open or confirmatory items identified in the SER. The NRC then conducted the pre-implementation audit of the DCRDR program at TPNP on April 2 through 6, 1984. The results of the NRC audit identified the resolved items and those items requiring additional information. The NRC stated that a meeting would be appropriate to discuss FPL plans, methods, and schedules for submittal of a supplement to the TPNP DCRDR Summary Report.

FPL met with the NRC on October 2, 1984, to discuss the outstanding items for the TPNP DCRDR Summary Report Supplement and the report was submitted to the NRC on April 1, 1986. Section 3 and Appendix 6B of the supplemental report identified the HEDs that remained open. FPL provided the NRC with a schedule for completion of the open HEDs on September 3, 1986, with a commitment to inform the NRC of any changes to the schedule.

On November 23, 1987, the NRC issued License Amendment No. 126 and No. 120 to the Facility Operating Licenses for Turkey Point Unit Nos. 3 and 4, respectively. These amendments added license conditions which require implementation of FPL's plan for the integrated scheduling of plant modifications for the TPNP. The I/S resulted in implementation of schedules for new and existing plant modifications and changes which reflect the importance of the items in relation to overall plant safety. This would be achieved by improved control of plant modifications or resource intensive activities and timely implementation of the modifications or activities. The amendment required NRC notification of changes in the schedule. Subsequent to the issuance of the amendment, the I/S became the method for tracking the status of open HEDs required by the NRC.

The status of the open HEDs specifically referenced by the alleger was as follows:

(1) Turbine Runback Selector Switch

The Turbine Runback Selector Switch allows the operator to choose inputs desired for the turbine governor and load limit runback initiating logic. The selector switch is a four position switch with the following positions:

NIS	Selects Nuclear Instrumentation System inputs to the turbine runback initiating logic.
RPI	Selects Rod Position Indication inputs to the turbine runback initiating logic.

NIS/RPI Selects both NIS and RPI inputs.

OFF Disables the NIS and RPI inputs.

The normal position of the selector switch is the RPI position. The switch position is annunciated in the Control Room to provide an alarm when the selector switch is in a position other than RPI, or when the logic matrix for the RPI portion of the selector switch fails to actuate.

The scope of the modification consisted in eliminating the "Off" position on the Turbine Runback Selector Switch. This modification was required to prevent the plant from returning to power operation with the switch erroneously left in the "OFF" position. The "OFF" position on the selector switch was designed to be used when the plant was in hot shutdown, cold shutdown, or refueling operations. Its purpose was to facilitate maintenance on the system. However, maintenance activities on the Turbine Runback System can also be performed when the selector switch is in the NIS position without altering the turbine runback initiating logic. This modification involves replacing the existing four position switch with a three position keylocked switch with position locations at 11 o'clock (NIS), 12 o'clock (RPI), and 1 o'clock (NIS/RPI). The new three position selector switch is essentially a one-for-one replacement for the existing Turbine Runback Selector Switch, and therefore this modification will not adversely affect the existing turbine runback initiating logic.

This modification was identified on the I/S as MOD 1245 for Unit 3 and MOD 1246 for Unit 4. MOD 1245 was completed and closed out in May of 1990 and the NRC was notified in the semi-annual update to the I/S in FPL letter L-90-345 dated September 20, 1990. MOD 1246 is currently scheduled on the I/S to be accomplished during the 1993 Unit 4 refueling outage with a completion date of April 1, 1993, which is 63 days ahead of the NRC commitment date of June 3, 1993.

(2) Control Room Lighting, HED Nos. 6.1.5.3.a. and 6.1.5.4.c. These two HEDs were identified as still being open in Appendix 6B of the DCRDR Supplemental Summary Report as follows:

(a) <u>Finding</u>: (Section 6.1, File No. 30, HED No. 6.1.5.3.a)

Control room ambient lighting is brighter than recommended 75 foot-candles on operators' desks; maximum recommended on main consoles, NIS panels. Emergency lighting too dim.

Planned Response:

Sunlight spectrum lighting will reduce light levels and glare. FPL is presently reviewing the emergency lighting problems and plans to make detailed light measurements for both normal and emergency lighting after the panels are painted. FPL is also conducting a new noise analysis due to removal of asbestos from the control room ceiling. These studies will be integrated to provide the best solution for noise and light problems.

Status:

The old lights have been replaced with sunlight spectrum lights (Dura Lite, 34 watts) which appear to have reduced glare problems. The control boards have been painted a lighter color that will brighten the room during emergency conditions. The planned light and noise surveys will be used to develop an improved control room environment if required.

(b) Finding: (Section 6.1, File No. X2, HED No. 6.1.5.4.c)

Inadequate emergency lighting levels on the vertical panels in the primary operating area (vertical panel B) does not meet 10 footcandle minimum requirement for primary operating area.

Planned Response:

Revise or add lighting fixtures to achieve 10 footcandles in all primary operation areas.

Status:

New lights have been installed and the vertical panels have been painted a lighter color. After start-up of Unit 4, FPL will perform a light survey to determine the adequacy of the lighting.

The commitments to the NRC for these HEDs were identified on the I/S as MOD 792. This MOD required the licensee to perform a control room lighting evaluation with a NRC commitment date for completion of October 27, 1991. The lighting study was completed by Tech-U-Fit Corporation in June of 1990 and the review by the licensee was completed November 21, 1990, as documented in JPN-PTN-90-5071. Since the commitment to the NRC was to perform a study only, MOD 792 was shown as complete on the I/S and the NRC was informed by FPL letter L-91-087 dated March 27, 1991. The study

indicated that the lighting in the control room could be improved. Although the NRC commitment was completed and the MOD removed from the I/S, FPL is still tracking the lighting HEDs on their own commitment tracking system (C-TRACK) under item numbers 87-0099-34 and 87-0100-34. It should be noted that even though the study identified areas for improvement, there have been numerous NRC inspections in the control room over the past several years, and inadequate lighting was not identified as an issue. For example; EOP team inspection members were directed to observe normal and emergency lighting throughout the plant when walking down EOP's; Preoperational testing inspections during safeguards testing required inspectors to be present in the control room while the control room was on emergency lighting for extended periods of time; NRC inspectors provided extended control room coverage during both unit startups after the dual unit outage; and the resident inspectors routinely tour the control room at various times.

(3) Control Room Annunciator HED Nos. 6.3.1.2.a.1 and 6.3.1.2.c.1. These two HEDs were identified as still being open in Appendix 6B of the DCRDR Supplemental Summary Report as follows:

(a) Finding: (Section 6.3, File No. 2, HED No. 6.3.1.2.a.1)

There are several alarms that occur so frequently that they become a nuisance and the operators disconnect them.

Planned Response: The nuisance alarms are to be corrected by eliminating alarms that are not needed and changing logic as a part of the annunciator system upgrade.

Status: Annunciator upgrade under study.

(b) Finding: (Section 6.3, File No. 5, HED No. 6.3.1.2.c.1)

Some alarms with multiple inputs do not have reflash.

Planned Response: Reflash capability will be available as required as part of the annunciator system upgrade.

Status: Annunciator upgrade under study.

The commitments to the NRC for these HEDs were identified on the I/S as MOD 1011. This MOD was similar to the lighting MOD (I/S MOD 792) in that the commitment on the I/S was to perform a control room annunciator study only.

The I/S showed the annunciator study to be completed by November 5, 1991. The study was completed on March 29, 1991, as documented in JPN-PTN-91-5011, and will be shown as complete in the next formal I/S submitted to the NRC. After the annunciator MOD is closed on the I/S the licensee will continue to track the recommendations from the study under C-TRACK item number 87-0103-34.

There has been a noted improvement in the past few years with regard to control room deficiency tags, which includes annunciators. There has been a continued reduction from a high of approximately 255 noted in the 1989 SALP report (NRC Inspection Report Nos. 50-250,251/89-36), to an all time low of 44 noted in the 1991 SALP (NRC Inspection Report Nos. 50-250,251/91-41). The licensee recently commenced tracking the number of annunciators in an alarm condition which is off-normal for the current plant condition. This is being used as an indicator for management to determine if increased attention is required. On November 7, 1991, there were a total of eight annunciators listed for this indicator (three for Unit 3 and five for Unit 4), which is an improvement over the past.

Recent inspection effort was reviewed to determine if there was any indication of a generic human factors concern. Both an ORAT (NRC Inspection Report Nos. 50-250,251/91-38) and an EOP Followup Team Inspection (NRC Inspection Report Nos. 50-250,251/91-33) reviewed portions of the licensee's human factors program.

The ORAT inspection results in the area of human factors were as follows:

The inspectors reviewed a sample of the NOPs and ONOPs to ensure that the procedures adequately incorporate human factors considerations and that the TPNP operations staff clearly understand and could use the procedures as written. The review consisted of: (1) a review of the procedure writer's guide, ADM-101; (2) comparison of the procedures against the administrative guidelines for procedural development; and (3) plant walkdowns of selected procedures with operations staff.

The inspectors reviewed the licensee's procedures writer's guide to ensure that it adequately addressed the previous concerns identified during the EOP Team Inspection (NRC Inspection Report Nos. 50-250/89-53) and incorporated the human factors principles as described in NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures." The licensee has incorporated revisions to the procedure writer's guide in response to the inspection findings. Most significantly, the writer's guide has been

expanded to include all operating, off-normal, and emergency operating procedures.
The procedures reviewed generally agreed with the requirements of the writer's guide. A sample of the procedures reviewed were walked down with operations staff to determine the adequacy of the procedures, and to ensure that appropriate controls and indications were presented. Particular emphasis was placed on reviewing the modifications to the Unit 3 and Unit 4 Emergency Diesel Generator controls. The team found that the procedures were adequately detailed and the operations staff were capable of performing the activities described in the procedures. In general, the equipment nomenclature used in the procedures matched the label identification on the equipment. In those cases where labelling discrepancies were identified, the licensee took the appropriate administrative actions to correct the discrepancies.

The inspectors reviewed the control room and local control panel revisions associated with the EPS Enhancement Project. The review consisted of: (1) an evaluation of the documentation supporting the control panel modifications; (2) review of the modifications through plant and control room walkdowns of the affected panels with operations staff; and (3) review of the resolutions to the HEDs identified during the design process.

The inspectors reviewed the licensee's documentation supporting the control panel modifications to ensure the design process adequately incorporated human factors engineering principles described in NUREG-0700, "Guidelines for Control Room Design Reviews." The inspectors found that the licensee had implemented an adequate process to identify important operator actions associated with the EPS, identify controls and indications necessary for those actions, and incorporate accepted human factors principles into the design of the control panel modifications.

The inspectors reviewed the control room and local control panel modifications to ensure that the operations staff recognized and understood the modifications, and to ensure that the appropriate controls and indications necessary for operator activities had been incorporated into the modifications. The inspectors found that the operations staff recognized and understood the modifications, and were capable of performing the activities associated with the affected control panels. The inspectors found that indications and controls were adequate for performing the required activities.

The inspectors reviewed the resolutions to the HEDs identified during the control panel design and validation process. In most cases the licensee has incorporated adequate design

modifications to resolve the HEDs identified, and had adequately documented the resolutions. However, the licensee did not adequately address the one major control panel HED identified during the performance validation process (PA-SEI-EPS.02, Discrepancy #1) related to distinguishing between the diesel "emergency start" and "rapid start" controls. The inspectors reviewed the discrepancy with the licensee, and the licensee initiated the appropriate administrative controls to resolve the concern.

The ORAT inspected the licensee's corrective actions associated with the human factors findings from the EOP Follow-up Inspection (NRC Inspection Report No. 50-250/91-33), dated September 3, 1991. The licensee implemented procedural revisions and control panel modifications in response to the inspection report findings. The inspectors found that the licensee adequately addressed minor discrepancies identified in Section 7 of NRC Inspection Report No. 50-250/91-33.

With regard to the EOP inspection team finding related to the actions taken to verify containment integrity following a phase A or phase B isolation (NRC Inspection Report No. 50-250/91-33, Section 2), the licensee has committed to incorporate additional procedural guidance into the EOPs to help ensure appropriate operator actions to allow for local or manual isolation of the affected containment penetrations. This is more consistent with actual isolation methodology. The ORAT found the proposed actions to be adequate.

CONCLUSION: ALLEGATION 5 - NOT SUBSTANTIATED

In summary the allegation could not be substantiated. Almost 400 HEDs per unit were identified by the initial DCRDR Report and the Supplemental Summary Report. The inspectors reviewed the status of open I/S Mods associated with HEDs and compared them to the licensees HED tracking system. Currently there are six open I/S Mods related to HEDs (Mods 550, 569, 1297, and 1298 are associated with switches; MOD 1011 is the annunciator study discussed previously; and MOD 1290 concerns the control room phone). The NRC has remained informed of HED status through formal meetings, audits, and correspondence prior to November 23, 1987. After that date status was formally provided by the I/S. The open status of the remaining six HEDs does not constitute a safety concern and the resolution of each item is scheduled via the I/S. Additionally, human factors is now incorporated into the overall design process by the administrative procedure O-ADM-006, Human Factors Review Program.

6. MODIFICATIONS POSTPONED DUE TO BUDGET OR OTHER CONSTRAINTS:

The statement of the concern was as follows:

Management's decision to postpone, due to budgeting or other constraints, important modifications such as the correction of the Power Mismatch Circuits to automatically control Reactor Power (thru direction and speed of rod insertion). Effort to initiate modification to install/restore power mismatch circuitry has been deadlocked. Power mismatch circuitry was inoperational in at least one of the two nuclear units. Spurious reactor trips with their unnecessary challenges to protection system have often occurred at TP (causing adverse effect on reactor vessel integrity), at least one as recently as 1990, with runbacks that were not survived at least partially as a result of inoperational rod control system.

DISCUSSION: The inspectors reviewed licensee's detailed procedure for prioritizing each PC/M based on a decision matrix. Approximately 50 percent of the importance weighting in the decision matrix is based on safety significance and being a regulatory requirement. The prioritzation process was determined to be adequate. During the ORAT, the inspectors verified that the PC/Ms that were being canceled for the dual unit outage did not present a safety concern. The results of the ORAT inspection follow:

For this DUO approximately 310 PC/Ms were planned to be accomplished and 22 of these were canceled. In order for the licensee to delete an activity that was initially planned for the outage, it had to be recommended by the applicable Department Head, Technical Department Supervisor, Outage Manager, Operations Superintendent, and Plant Manager, and approved by the Site Vice President. The recommendations and approval are documented on Attachment 3 of O-ADM-003, Outage Management. The inspectors reviewed the 22 PC/Ms that were deleted and agreed that they did not impact plant safety. The canceled PC/Ms ranged from modifying components for system enhancement to installing removable hand rails at the containment equipment hatch area. Eleven of the canceled PC/Ms were replaced by 14 other PC/Ms that the licensee considered to be more important than the original PC/M. For example, PC/Ms 90-301, -304, and -305, to modify 11 pipe supports, were postponed in order to procure, install, and test the hydrogen recombiner. In addition, the canceled modifications were added as candidates for either the "Top 20" or "Top 30" lists. These lists were recently implemented by the licensee to control the number of modifications being installed in the plant. In order for a modification to be installed it must be listed on the "Top 20" list (modifications scheduled for the next outage) or the "Top 30"

list (modifications that can be accomplished on-the-line or during short notice outages). For a modification to be added to the lists there must be room for it or a modification currently on the list must be canceled and the new modification added. The inspectors considered this an excellent method of controlling the number of changes occurring in the plant at any one time.

The inspectors specifically reviewed the power mismatch circuit to access the PC/Ms made to the circuitry and to review its operability.

The power mismatch circuit is a part of the automatic rod control system and is classified as non-safety grade. When the rod control system is in automatic, the power mismatch circuit will respond to a rapid change between nuclear power (Q_N) and turbine load (Q_T). Signals generated are then sent to the rod speed and direction program restoring the balance between Q_N and Q_T.

The reactor control system is designed to enable the reactor to follow load reductions automatically when the output is approximately 15% of nominal power. Control rod positioning (insertion) automatically occurs when output is above this value. In addition manual control rod positioning may be performed at any time.

The inspector reviewed the following plant procedures and concluded that detailed and specific instructions are provided that specify conditions when the rod control system is to be in the automatic mode. Instructions also direct plant operators to place the rod control system in manual for equipment malfunction or off normal events where automatic control is not stabilizing and maintain plant conditions.

- 4-GOP-103, Power Operation to Hot Standby
- 4-GOP-301, Hot Standby to Power Operation
- 3-ONOP-028, Dropped Rod
- 4-ONOP-059.8, Power Range Nuclear Instrumentation Malfunction
- 3-ONOP-089, Turbine Runback

The inspectors reviewed I&C Maintenance Instruction 41-017, T_{ave} to Rod Speed Control and Power Mismatch, which is used for loop calibration of the power mismatch circuit. The circuitry for both units was calibrated during the current DUO in January 1991. The calibration data was found to meet procedure acceptance criteria. In addition to the calibration test a monthly operability test is performed on the power mismatch circuit when the plant is operating

above 15% power. The power mismatch circuit monthly operability checks are performed in accordance with surveillance procedure 4-OSP-059.4, Power Range Nuclear Instrument Analog Channel Operational Test.

The inspectors held discussions with I&C engineers and operations personnel concerning the operating history of the power mismatch circuit. The inspectors concluded as a result of these discussions that the rod control system has been primarily operated in manual on both Units. The licensee stated that the reasons the control system has been operated in manual are because of calibration problems (defective electronic components) and temperature deviation problems (- 1/2°F) between T_{ave}-T_{ref}. The latter was causing rods to move in. These problems were corrected during the DUO.

The inspectors reviewed the following PC/Ms which were implemented over a period of years and affected the rod control system and the power mismatch circuit.

- PC/M 81-13 (Unit 3); 81-14 (Unit 4), Deletion of Power Mismatch Circuitry from the Rod Control System
- PC/M 83-88 (Unit 3); 83-89 (Unit 4), Deletion of Flux Rate Input to Turbine Run Back
- PC/M 84-208 (Unit 3), 84-209 (Unit 4) Reinstatement Power Mismatch Circuits Without Automatic Rod Withdrawal
- PC/M 84-210, (Unit 3), 84-211 (Unit 4), Turbine Runback Modifications

The NRC IE Information Notice No. 79-22, Qualification of Control Systems, dated September 14, 1979 notified licensee that the rod control systems (non-safety grade system) could potentially malfunction due to a high energy line break inside or outside containment. The licensee's long term corrective action was described in FPL letter L-79-284 dated October 8, 1979. PC/M 81-13, and PC/M 81-14 were implemented and removed the power mismatch signal and modules which eliminated all automatic control rod functions.

PC/M 84-208 and 84-209 restored power mismatch circuitry for automatic rod insertion only and removed the rod withdrawal capability. The purposes of these modifications were to enhance operational control during turbine runback events and to maintain the purposes of PC/M 81-13 and PC/M 81-14 which prevent a rod withdrawal event due to a steam line break.

A Request for Engineering Assistance, REA 89-667, Restore Symmetry to Power Mismatch Circuit, was approved by Engineering July 1991. The REA restores symmetry to the power mismatch circuit by slowing

the control rod insertion rate during the latter part of the turbine runback and reduce possible excessive reactor coolant system temperature decrease.

During an earlier inspection conducted August 26-30, 1991 the power mismatch circuit for rod control was reviewed. REA 89-667 had addressed a concern that RCS temperature may decrease significantly below set point during a turbine runback due to the power mismatch circuitry of the Rod Control System not having symmetry. The existing power mismatch circuit can only accelerate initial rod insertion, it can not slow it later during the transient.

The simulator was used to investigate whether a plant stability problem exists. The licensee conducted several turbine runback scenarios on the plant simulator to assess if plant stability is achieved with the current power mismatch circuit installation. The turbine runback scenarios were conducted using the existing power mismatch design and also with changes contained in REA 89-667. Plant parameters (T_{ave} and T_{ref}) showed very similar responses for both designs with no stability problem identified. After reviewing the copies of the computer printouts which displayed the plant parameters (T_{ave} and T_{ref}) the inspectors agreed that the need for immediate changes to the power mismatch circuit would not be required and would not present a safety concern. It was the opinion of the I & C Supervisor and the Operations Supervisor - Nuclear that the present runback results were acceptable and the addition of the symmetry (negative feedback) modification would enhance the system but was not required. The inspectors observed that the power mismatch circuit is operable without the symmetry modification (REA 89-667) which is planned, but is not presently on the plant's "Top 20" list.

The inspectors reviewed all reactor trips that occurred from January 1, 1990, to November 4, 1991, to determine if there were any spurious reactor trips or runbacks which resulted in a reactor trip, at least partially as a result of inoperational rod control system (e.g. inoperable Power Mismatch Circuit). A summary of the reactor trips is listed below in chronological order.

- On April 9, 1990, at 6:14 p.m., Unit 4 tripped while at 100% power. The trip was initiated by the failure of UF relay No. 4B2 which indicated an UF condition of less than 56.1 Hz on the 4B 4Kv bus. No UF condition existed, but the failed relay monitors the 4B 4Kv bus which feeds the 4B and 4C RCPs. The false UF signal tripped the 4B and 4C RCP breakers which resulted in a reactor trip. All safety systems functioned as designed. Low flow from the charging pumps was experienced during the recovery operation and the licensee's investigation showed that the calibration of VCT level transmitter LT-115 was out by 5% inhibiting the automatic switch over of the charging pump suction from the VCT to the RWST. Degraded charging pump flow occurred when the VCT level went to zero

and hydrogen from the VCT was inducted into the charging pumps. Unit 4 was scheduled to be brought down on April 12, 1990, for safeguards tests in conjunction with Unit 3 which is presently in a refueling outage. Unit 4 remained in Mode 3 for short notice outage work until the safeguards test was conducted.

- On May 26, 1990, at 5:56 a.m., Unit 4 was inadvertently manually tripped while at approximately 1% power. No SI occurred and plant conditions remained fairly constant. The licensee was in the process of filtering the turbine lube oil to remove metal fragments (reference NRC Inspection Report Nos. 50-250,251/90-14) by conducting 4-OSP-089, Main Turbine Valves Operability Test, steps 7.2.4 thru 7.2.11 and 7.2.55 during which the main turbine was latched and tripped ten times to facilitate lube oil clean up. During the time the lube oil flush was in process the Unit 4 reactor was at 1% power with control rods withdrawn. Following the flushes and verification that no metal fragments were found following the last time the main turbine was tripped, the decision was made to conduct 4-OSP-089 to complete the surveillance. Step 7.2.59 states "Trip the Reactor Trip Breakers or continue plant startup in accordance with the requirements of the applicable GOP (N/A if breakers were not reset in Step 7.2.8)." When the RCO reached step 7.2.59 he obtained the PSN's concurrence and tripped the reactor trip breakers resulting in a reactor trip. One contributing factor was the sequence of performing 4-OSP-089. The startup procedure, 4-GOP-301, Hot Standby to Power Operation, step 5.3, has the operators perform Section 7.2 of 4-OSP-089 prior to opening the MSIVs in preparation for warming the main steam header prior to reactor startup. The operators were familiar with accomplishing step 7.2.59 of 4-OSP-089 with rods inserted.

- On June 9, 1990 with Unit 3 in Mode 1 at 26% power the unit experienced an automatic turbine trip and subsequent reactor trip at 6:47 a.m. due to High-High level in the "C" SG. The operators had placed the unit online at 6:37 a.m. that day and were preparing to increase load when the operators noted the "C" SG feedwater level increasing and increased demand signal on FC-498F to the main feedwater regulating valve (FCV-498). The flow controller (FC-498F) was still in manual. The operator attempted to close the valve by pushing the decrease button on FC-498F. However, the SG water level continued to rise. The operator tried to close the feedwater isolation valve to the "C" SG. With SG NR level >75% the RCO manually tripped the reactor. A review of the DDPS printout revealed that the reactor tripped automatically approximately .20 seconds before the RCO manually tripped the reactor. The turbine tripped on High-High SG level (80% NR) which caused the subsequent reactor trip. The plant received a feedwater isolation and AFW initiation as expected. Investigation of

FC-498F revealed that the manual/auto pushbutton for increased feedwater flow stuck closed. I&C technicians replaced the flow controller and the plant restarted on June 11, 1990.

- On June 15, 1990, Unit 3 automatically tripped from approximately 10% reactor power. The turbine had been manually removed from service due to high conductivity in the steam generators due to condenser tube leaks. The operators were performing this evolution in accordance with procedure 3-GOP-103, Power Operation to Hot Standby. Prior to tripping the turbine, the operators were required to verify that reactor power was below the P-10 setpoint (10% indicated on PRNIS) and that turbine power was below the P-7 setpoint. These conditions were satisfied; however, the RCO noted T_{ave} decreasing due to the imbalance between the reactor power level and turbine load. The turbine load was maintained at approximately 35 MWe which was drawing off too much steam for the reactor system to maintain T_{ave} stable. The control rods were inserted previously to lower power level below the P-10 setpoint. The RCO decided to withdraw control rods to increase T_{ave}. However, the RCO did not monitor reactor power level. The turbine was manually tripped with reactor power below 10%. However, power was increasing and reached 10 percent .15 seconds after the turbine was tripped, enabling the "at-power" reactor trips. At this point the reactor tripped due to the presence of the turbine trip signal with reactor power above the P-10 setpoint. Following the trip, the plant was stabilized in Mode 3. In summary, the PSN did not adequately direct the Unit 3 RCOs as the unit was being taken offline. The resulting poor communication between the RCOs independently controlling the reactor and the turbine led to reactor power increasing above the P-10 setpoint (10% reactor power) and the subsequent automatic reactor trip.

- On August 12, 1990, at 4:28 p.m., with Unit 4 at 100%, a reactor trip occurred due to Low-Low level in the "A" SG. The event was caused by the 4B condensate pump tripping on overcurrent which was immediately followed by a trip of the 4A feedwater pump. The trip of the feedwater pump initiated a turbine runback to less than 60% power as designed. SG levels dropped below 15% narrow range due to shrink caused by the combined effects of a partial loss of feed flow, turbine runback, and subsequent reactor trip. The trip of a running condensate pump will normally start the standby condensate pump and not trip the feedwater pump if the swap occurs within five seconds. The five seconds is timed by an Agastat relay in the feedwater pump breaker trip logic. Upon investigation it was discovered that the Agastat relay was set at .15 seconds in lieu of the required five seconds. The low setting of the relay did not allow enough time for the start of the standby condensate pump to be sensed by the breaker trip logic and therefore a SGFW pump trip signal was generated. The

relay was reset to 5.0 sec ± 10% for the 4A feedwater pump and the relay for the 4B feedwater pump was also reset after testing found it to be set at 3.3 seconds. The unit was subsequently returned to service at 4:43 a.m. on August 14, 1990.

- On October 3, 1991, at 11:57 a.m., the Unit 3 reactor was manually tripped from 50% power due to a sudden decrease in turbine/generator load. The power decrease was caused by the loss of turbine control oil pressure resulting from a break in the control oil piping near a turbine intercept valve. No automatic reactor trip signal was generated since turbine auto stop oil pressure was not lost and both turbine stop valves did not fully close. Following the manual reactor trip, all safety systems responded as designed, and one SG safety valve lifted briefly. Initial root cause evaluation attributed the pipe break to fatigue stress of a threaded pipe. The licensee repaired the control oil piping and then restarted the unit on October 4, 1991, at 5:53 a.m., to continue the startup program following the extended DUO.

CONCLUSION: ALLEGATION 6 - NOT SUBSTANTIATED

The licensee's process for prioritizing modifications was determined to be adequate. During the ORAT, the inspectors verified that the PC/Ms that were being canceled for the DUO did not present a safety concern. The Power Mismatch Circuit, without the modification to restore symmetry, has been verified to be operational and in use. With respect to the reactor trips, two of the six trips were caused by personnel error (May 26, 1990 and June 15, 1990); the remaining four trips were due to equipment failure. Based on the inspectors review of the six reactor trips that occurred since January 1, 1990, there were no spurious reactor trips or runbacks that were caused, at least partially, as a result of an inoperational Power Mismatch Circuit or because of lack of a restore symmetry modification to the Power Mismatch Circuit. This concern was not substantiated.

7. ETHNIC DISCRIMINATION AGAINST "CUBAN-AMERICANS":

The statement of the concern was as follows:

Ethnic discrimination against "Cuban-Americans."

DISCUSSION: This allegation was not inspected, because of its being within the jurisdiction of the Equal Employment Opportunity Commission. The alleger was notified that he should identify this concern to the EEOC for their disposition and he was given the necessary information on how to contact the EEOC.

CONCLUSION: ALLEGATION 7 - NOT INSPECTED

8. EMPLOYEE PROTECTION FROM DISCRIMINATION:

The statement of the concern was as follows:

Violation of Federal regulations concerning protection from discrimination against Employees for expressing to Management and or the Nuclear Regulatory Commission concerns about Nuclear Safety as is clearly defined in NRC Form 3.

DISCUSSION: NRC Form 3 states, "Federal law prohibits an employer from firing or otherwise discriminating against a worker for bringing safety concerns to the attention of the NRC." As stated in paragraph 1, the team's objective was to determine if there existed any unsafe engineering practices or operating conditions or if personnel practices resulted in a chilling effect with regard to pursuing a safety issue. The US Department of Labor is evaluating the specific case of employee discrimination. The NRC will monitor the Department of Labor activities regarding this case for potential enforcement. For this allegation, the team objective was to determine, in the general sense, if there were practices, especially in the Speak Out and Fitness For Duty programs, which prohibited or discouraged engineers from pursuing nuclear safety concerns.

Because it was alleged that the Speak Out Program was being used to discriminate against employees, the inspectors conducted an interview of the Juno Beach Engineering Staff. As discussed in paragraph 1, open and candid discussions were conducted with over 60 engineers, 43 of whom were in non-supervisory positions. There were some comments, the sum of which, in the judgement of the team, indicated some anxiety over the pending FPL reorganization, but did not indicate a lack of freedom to discuss this concern with the NRC and did not indicate management engagement in discrimination.

Review of Speak Out files indicated that there were individuals in supervisory positions who were reprimanded for harassing employees who allegedly raised safety concerns. One case, as recent as 1991, involved the removal of the supervisor. The licensee's executive management has made it well known through their General Employee Training that it is contrary to FPL policy to take adverse employment action against any individual who raises safety concerns.

It was alleged that the Speak Out Program did not protect the identity of individuals. The engineering interviews did indicate a concern that Speak Out could not maintain confidentiality. The inspectors reviewed the Speak Out process for protecting the identity of individuals who raise concerns. Speak Out purposefully does not maintain a list of individuals who have used the program.

Speak Out uses a sequential numbering system to assign a specific number for each concern. The inspectors determined that this procedure would aid in preventing inadvertent disclosure of an individual's identity.

There are cases when an individual's identity could not be separated from the issue, or the investigation reached a point where the individuals identity could be compromised. At that point the individual was advised. If the individual was satisfied that the concern has been satisfactorily addressed, then the issue was closed. If the individual was not satisfied, then the desire for confidentiality was revisited. In some cases, Contractors were used to investigate concerns when special expertise was required in protecting the individual's identity.

The engineering staff interview results indicated that there was a perception that individuals who raise safety concerns to Speak Out would be known; however, the interview results also indicated that a very small number of individuals using Speak Out were actually known; and of those that were known, it was primarily because the individuals told other employees that they had raised concerns to Speak Out. The interview results also indicated that some individuals had a perception that their identities would not be protected. However, most of these individuals had neither used Speak Out nor knew of individuals who had gone to Speak Out while desiring confidentiality.

During the inspection of various concernee followup techniques that Speak Out was using, the determination was made that it would be beneficial if the individual who raised a concern, had a better understanding of what identity protection was. Speak Out concurred with the inspectors observation and initiated a guidance letter dated October 31, 1991, which addresses "Confidentiality of Employees Bringing Concerns to Speak Out." The stated objective of the letter was that "the confidentiality and anonymity of our concernees is a very important goal of this program and should be emphasized at all times."

The inspectors concluded that Speak Out has made efforts to protect individuals' identities. By the issuance of the October 31, 1991, letter from the Manager Nuclear Safety Speak Out to the Vice President, Nuclear Assurance, FPL was making additional effort to inform employees of the actions taken to provide confidentiality when concerns are brought to Speak Out.

The licensee was alleged to be using psychological testing and drug testing to discriminate against employees who voice safety concerns. In general, the allegation stated that the licensee used the NRC's required Fitness for Duty program to retaliate through harassment and intimidation, against employees who have taken safety concerns to the Speak Out organization. Specifically, when interviewed, the alleger stated that he was drug tested eight times

in one year, and was directed, without justification, to be psychologically evaluated by a contract psychologist.

10 CFR Part 26, Fitness for Duty Rule, effective January 3, 1990, requires a licensee to provide for a Fitness for Duty program which identifies not only drug and alcohol abuses but also, "...mental stress, fatigue, and illness...." Additionally, Part 26 requires, "...an employee assistance program to achieve early intervention by offering assessment, counseling, referral, and treatment of employees with problems that could adversely affect their performance...." It is the objective of Part 26 that nuclear plant personnel perform their duties in a reliable and trustworthy manner and are not mentally or physically impaired from any cause which in any way would adversely affect their ability to safely and competently perform their duties.

Given the allegation and regulatory requirements as stated above, the inspector audited records relative to random and "for cause" drug tests and psychological evaluations, and then compared that information with the use of the Speak Out program. It should be noted that due to extensive confidentiality, and in many cases anonymity, in the Speak Out records, the inspector could not in all instances verify the identity of the Speak Out user for purposes of cross-indexing to drug and psychological testing records. The Quality Assurance audits of the licensee's Fitness for Duty program were reviewed, as was the licensee's Supervisor Fitness for Duty training handbook. It is noted that prior to this allegation, the NRC had inspected the Fitness for Duty program at the Juno Beach Corporate Office, St. Lucie, and TPNP. No violations were identified in these two inspections (NRC Inspection Report Nos. 50-250,251/91-40 and 50-335,389/91-05).

In early 1991, the licensee concluded that Juno Beach employees who were badged at both St Lucie and TPNP were statistically more likely to be randomly chosen because they were in both population pools. Consequently, some personnel were being drug tested more than statistically expected due to being in the two separate population pools. However, as of March 1991, all multi-badged individuals at Juno Beach were only in the St. Lucie population pool and therefore on an equal random selection basis with all other personnel. This resolved the concern that Juno Beach employees were randomly chosen for drug tests more often than their fellow plant coworkers

Formal interviews were conducted with three supervisors and four coworkers of the alleger. The licensee's Ombudsman was also interviewed. As noted elsewhere in this report, a total of 43 employees in the licensee's Nuclear Engineering Department were interviewed relative to use of Speak Out and no corroboration of the allegation was established.

Based upon the inspection of various sources of FFD information, the inspector determined the following relative to drug testing:

- All of the alleger's drug tests occurred prior to, and not after, his use of Speak Out.

- From the effective date of the NRC's Fitness for Duty Rule (January 3, 1990) until the date of his termination (August 19, 1991), the alleger had been randomly tested four times, along with 479 other employees and contractors each of whom had been tested on four or more occasions during the same time period (as documented by an independent laboratory).

- In accordance with the NRC Fitness For Duty Rule, the licensee has randomly tested at least 100% of the plant population at each of its two nuclear stations on an annual basis. Statistically, random drug testing has resulted in individuals being tested from one to eight times. The alleger has been tested four times which is approximately the mean of the testing distribution.

- The alleger was not one of the 34 individuals who had been tested "for cause" as of August 19, 1991.

- Slightly less than half of all the Speak Out users have been randomly drug tested which coincides with the fact that approximately half of all staff have been randomly drug tested.

- Specifically, with respect to the Juno Beach Corporate Office, approximately 33% of the Speak Out users were tested prior to, and not after, their visit to Speak Out, and approximately 25% were tested after, and not before, their visit to Speak Out.

- Of all the random drug tests given to all the Speak Out users at Juno Beach, exactly 50% occurred prior to, and 50% occurred after visiting Speak Out.

- Only one individual was psychologically evaluated, visited Speak Out (before and after the evaluation) and was randomly drug tested (before and after use of Speak Out).

With respect to that part of the allegation regarding the required psychological evaluation, the inspector determined the following:

- Psychological evaluations were initiated by the licensee in January 1986, as part of its screening program prior to granting access to the nuclear sites.

- There have been 10 individuals, other than the alleger, who have been directed by management to be psychologically evaluated; two resigned, seven were still employed, and one was released, based in part on the results of the evaluation. The alleger was the only individual who refused a management directed psychological evaluation. The inspector found no inappropriate or discriminatory use of psychological evaluation requirements.

- The alleger expressed concerned about an evaluation by a psychologist employed by FPL who would not allow his evaluation to be recorded and would not allow the alleger's attorney to observe the evaluation. While the licensee's contract psychologist would review another evaluation from a psychologist of the alleger's choosing, he considered the presence of a third party and the recording of his evaluation to be contrary to professional standards.

- FPL initiated the requirement that all employees must be psychologically tested using the Minnesota Multi-Phasic Personality Inventory. While 10 CFR Part 26 allows "grandfathering," with respect to the psychological test for some employees, it does not prohibit broadening the scope of the psychological test requirement. Inspection of the licensee's use of the test results revealed no discriminatory practice.

CONCLUSION: ALLEGATION 8 - NOT SUBSTANTIATED

Based on the results of the engineering staff interviews and the inspection of documented employee concerns, this allegation was not substantiated. The inspection did not substantiate that the Speak Out Program is being used to discriminate against employees who raise safety concerns. Based upon the above described inspection effort, no correlation could be found between the drug testing and psychological evaluation, and the identification of employee concerns to FPL management, Speak Out, or the NRC. Analysis of the FFD screening data indicated only random use of the program. The inspection indicated no correlation between disciplinary action and going to Speak Out or being Psychologically tested. The licensee was in compliance with 10 CFR Part 26, therefore the allegation regarding the misuse of the Fitness For Duty program was not substantiated.

9. RELIABILITY OF OVERPRESSURE MITIGATION SYSTEM:

The statement of the concern was as follows:

Request for NRC investigation of reliability of "all other relevant aspects of control system reliability for such important systems as the Overpressure Mitigation System..." Absence of documented defensible calculations for Overpressure Mitigation System that can guarantee adequate margin between setpoints. Less than safety-grade surveillance practices and calibration practices on OMS. Less than safety-grade equipment control from procurement through components' traceability to maintenance. Reliance on control-grade overpressure mitigation system. Incertitude of OMS as to a single failure criteria. The validity of [reactor vessel] Pressure-Temperature limits is controversial and inconclusive.

DISCUSSION: PC/M 75-81, Nil Ductility Transition Temperature Control, was implemented on January 6, 1978 for Unit 3, and on November 9, 1977 for Unit 4. This PC/M modified PORV control circuits to provide low pressure relief settings. The setpoint of 415 psig for low temperature operation (below 300 degrees F) is designed to keep the primary loop pressure below the 10 CFR 50 Appendix G limits. The following PC/Ms were subsequently implemented to meet additional design requirements: PC/Ms 78-27,-28, Overpressure Mitigation System - Permissive Status Panel Light and Annunciator Interlocks; PC/Ms 78-16,-17, Pressurizer PORVs Backup N-2 Supply; PC/Ms 78-23,-24, OMS Test Switch and Relabel OMS Components; PC/Ms 81-162,-167, Installation of Inadequate Core Cooling System Instrumentation; PC/M 86-50, Nitrogen Backup Supply Pressure Regulator Replacement for OMS; PC/Ms 88-396,-399, PORV Diaphragm Replacement and Lockwasher Addition; and PC/Ms 88-427,-535,-565, Pressurizer PORV Air and Nitrogen Supply Tubing Enhancements.

The pressurizer PORVs are spring-loaded-closed. Air is required to open the valves and is supplied by instrument air. In the event of a loss of instrument air, a backup N-2 system is provided which will supply enough N-2 for a minimum of ten minutes of operation. Drawing 5610-M-339 shows the N-2 backup system provided for each PORV. Each PORV has two redundant solenoid valves which are energized in order to open the PORVs. These solenoid valves fail closed on a loss of power. However, each solenoid is powered off the 125 volt vital DC supply. Therefore on a loss of offsite power, the station batteries will be available to allow the operation of the PORV. Drawings 5613-E-25, sheet 64, and 5614-E-25, sheet 64, show the wiring configuration and power supply for the PORV solenoid valves for Unit 3 and 4 respectively.

There are two PORVs and their associated block valves which are shown on drawing 5610-T-E-4501. If one PORV is inoperable, the remaining PORV is capable of relieving the RCS to prevent exceeding Appendix G limits. If the PORV fails in the open position, its associated block valve can be closed to isolate the PORV to terminate the pressure transient. Drawings 5613-E-25, sheet 27, and 5614-E-25, sheet 27, show the wiring configuration for the motor operated block valves. By referencing the breaker list, the inspector verified that the block valves were powered from a separate vital power source. The block valves are powered from the vital portion of the 3B/C and 4B/C MCC for Unit 3 and 4, respectively. Each block valve fails as is. The failure of one block valve will not affect the operability of the associated PORV, therefore it would not create a pressure transient.

Each PORV is opened by the energizating of two solenoid valves which realign to allow instrument air or N-2 to flow to the PORV actuator. These solenoids are redundant such that the failure of one will prevent the PORV from opening. If the PORV was open and the solenoid valve failed, the PORV would fail closed. However, the remaining PORV would not be affected and could be used to mitigate the pressure transient.

Drawing 5610-T-D-16A shows the control system for the OMS. Each PORV has its own switch installed on the main control board. The operator can enable/disable the OMS by selecting "LO Pressure OPS" or "Normal OPS," respectively. The setpoint pressure and actual pressure are derived from redundant temperature and pressure transmitters. PORV 456, which is the primary OMS channel, uses TE-430B and PT-403. PORV 455C, the backup OMS channel, uses TE-423B and PT-405.

Through inspection of responsible maintenance and engineering personnel activities, the inspectors determined that OMS, including the PORV and block valves, are treated as safety related equipment. The following I & C maintenance procedures were reviewed to ensure the OMS associated equipment was maintained and calibrated in accordance with safety related procedures: 3/4-PMI-041.10, RCS Subcooling Margin Monitoring Train B Calibration; 3/4-PMI-041.22, Reactor Coolant Pressure, Wide Range, P-3-405 Channel Calibration; 3/4-PMI-041.39, RCS PORV Actuator Overhaul/Maintenance PCV-*-455C and PCV-*-456. Operations department surveillance procedure 3/4-OSP-041.4, Overpressure Mitigating System Nitrogen Backup Leak and Functional Test, preforms the surveillance required by TS 4.4.9.3.1.a. The inspectors also reviewed the Total Equipment Data Base which lists all components and their safety classification for systems at the facility. This list indicated that components associated with OMS and the PORVs were designated as safety related. The list of PC/Ms was reviewed and all PC/Ms associated with OMS were classified as NSR or SR in lieu of NNSR or QR. This indicated all PC/Ms associated with OMS were treated as safety related PC/Ms.

In addition, the licensee responded to Generic Letter 90-06, Resolution of Generic Issues 70 and 94, in FPL letter L-90-396 dated December 21, 1990. Generic Issue 70 addresses "Power-Operated Relief Valve and Block Valve Reliability," and Generic Issue 94 addresses "Additional Low-Temperature Overpressure Protection for Light-Water Reactors." In summary, the licensee's response to these issues indicated the PORVs and block valves are currently treated as safety related according to the Quality Assurance Program with regard to the TEDB, maintenance, and procurement.

In an effort to determine if there are documented defensible calculations for OMS setpoints, the inspector reviewed the letter from Westinghouse to FPL on Heatup and Cooldown Curve and Overpressure Mitigation System Setpoint Instrument Uncertainties dated September 13, 1988. The letter contained a review of the overpressure mitigation system setpoints. The letter stated in part:

> The Overpressure Mitigation System provides a means of reducing the possibility of Reactor Coolant System overpressure transients from exceeding the pressure-temperature limits on the reactor vessel during heatup and cooldown operations. This is accomplished by using the Power Operated Relief Valve's as a means of relieving potential cold overpressure events.
>
> In order to provide overpressure mitigation, the Overpressure Mitigation System senses Reactor Coolant System pressure. When Reactor Coolant System pressure exceeds the Overpressure Mitigation System setpoint, the Power Operated Relief Valves are signaled to open. Due to control system delays and Power Operated Relief Valve opening times, the Reactor Coolant System pressure will overshoot the setpoint pressure by some amount. The amount of overshoot depends on the severity of the transient.
>
> In determining Overpressure Mitigation System setpoints, therefore, this pressure overshoot is accounted for so that the design basis cold overpressure transient will not exceed the Technical Specification pressure-temperature limits. The design basis transients assumed are more severe than transients that might be expected to occur at the plant. In addition, the setpoint calculation methodology includes several conservatisms. This combination of conservative assumptions for postulated transients and conservative setpoint calculations, makes the additional inclusion of instrument uncertainties unnecessary to prevent vessel damage due to realistic plant transients.

The inspectors concurred with the Westinghouse conclusion that because of the safety margin designed into the limit curves, the OMS setpoint uncertainties need not be included in the OMS setpoints.

The inspector reviewed OMS - Final Report dated February 14, 1989. This was the final report on the evaluation of the PORV opening times. The inspector reviewed the analytical basis for these setpoints and determined that they were adequate.

The inspectors reviewed the safety evaluation JPN-PTN-SEMJ-88-076 calculations for OMS PORV stroke times. The safety evaluation concluded that for the most limiting pressure transient event the OMS could mitigate the transient with the tested PORV stroke times as long as 3.45 seconds. The stroke time of 3.45 seconds was beyond the 2.0 second PORV opening time specified in the OMS Safety Evaluation Report dated March 14, 1980. The NRC had previously investigated this and issued violation No. 50-250,251/89-27-01. The NRC reviewed the licensee's response and concurred with the corrective actions as discussed in NRC Inspection Report Nos. 50-250,251/90-25.

The NRC has evaluated the OMS setpoints for adequacy with respect to brittle fracture at TPNP. Beginning in June 1988, the NRC began verification that the licensee had implemented commitments relating to Unresolved Safety Issue A-26, Reactor Vessel Pressure Transient Protection. The plant modified PORV control circuits to provide low pressure relief settings. The setpoints were used to keep the primary loop below the Appendix G limits for low temperature operations. This is documented in NRC Inspection Report Nos. 50-250,50-251/88-14.

The inspector reviewed the SER issued by NRC related to amendment number 55 for Unit 1 and amendment number 47 for Unit 2. The staff concluded that the assumption for these calculations were conservative.

The inspectors reviewed the original pressure/temperature limitations curve and the most recently updated curve. The curve had been appropriately updated to reflect plant aging.

The inspectors determined that licensee's OMS setpoint is adequate with respect to the higher brittle fracture susceptibility at TPNP.

The inspectors reviewed the substantive documentation supporting the validity of fracture toughness methodology for calculating the reactor vessel pressure/temperature limits. The inspectors reviewed the recent history of radiation embrittlement of reactor vessel materials at TPNP. In May 1988, the NRC issued Regulatory Guide 1.99, Radiation Embrittlement of Reactor Vessel Materials, Revision 2. The Regulatory Guide provided the staff position for the implementation of General Design Criteria 31 of 10 CFR Part 50

Appendix A. General Design Criterion 31 also requires that the design reflect the uncertainties in determining the effects of irradiation on material properties. Appendix G, "Fracture Toughness Requirements," and Appendix H "Reactor Vessel Material Surveillance Program Requirements," which implement, in part, Criterion 31, necessitate the calculation of changes in fracture toughness of reactor vessel materials caused by neutron radiation throughout the service life. The guide described general procedures acceptable to the NRC staff for calculating the effects of neutron radiation embrittlement of the low-alloy steels currently used for light-water-cooled reactor vessels. The Advisory Committee on Reactor Safeguards has been consulted concerning this guide and has concurred in the regulatory position.

On July 12, 1988, the NRC issued Generic Letter 88-11, NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact On Plant Operations. The purpose of the Generic Letter 88-11 was to identify that NRC intended to use Regulatory Guide 1.99 in reviewing submittals regarding pressure/temperature limits and for analyses other than pressurized thermal shock that require an estimate of the embrittlement of reactor vessel beltline materials.

On September 21, 1988, FPL submitted a proposed license amendment to incorporate revised pressure/temperature limit curves that were applicable for 20 effective full power years of service life. The new curves were developed using Regulatory Guide 1.99 and therefore, the submittal also satisfied the reporting requirements of Generic Letter 88-11.

On January 10, 1989, the NRC issued Amendment No. 134 to Facility Operating License No. DPR-31 and Amendment No. 128 to Facility Operating License No. DPR-41, in response to the September 21, 1988 request. As stated in the NRC's SER which was enclosed with the amendments, the NRC staff found that FPL's submittal was acceptable and that the neutron embrittlement calculation was in accordance with Regulatory Guide 1.99.

Additionally, the inspectors evaluated the final decision of the ASLAB, 50-250-OLA-4 and 50-251-OLA-4, dated June 24, 1991, which concluded that there were no unresolved issues relative to pressure/temperature limits for the reactor coolant system at TPNP.

Based on the review of the documentation listed above the inspector concluded that the determination of the pressure/temperature limits at TPNP were performed in accordance with the latest industry and regulatory guidance. Additionally, the NRC concluded that the current pressure/temperature limits were valid.

CONCLUSION: ALLEGATION 9 - NOT SUBSTANTIATED

Based on the above documentation and inspection, the OMS is designed, maintained, and operated as a safety related system. The methodology used to determine OMS setpoints and pressure/temperature limits comply with the industry and regulatory guidance. Consequently, this allegation was not substantiated.

10. RELIABILITY OF EXISTING SETPOINT PROGRAM:

The statement of the concern was as follows:

Request for NRC to investigate reliability of the existing setpoint program. Prematurely removed from setpoint effort for attempting to extend this methodology to balance of plant equipment such as Overpressure Mitigation System.

DISCUSSION: To address this allegation, a "Setpoint Methodology Inspection" was conducted on the FPL Instrument Setpoint Program, including its documentation, implementation, and end product quality (i.e. setpoint calculations). One objective of the SMI was to determine if the existing setpoint methodology in use by FPL conforms to industry standards and Regulatory Guide 1.105, Instrumentation for Safety-Related Systems.

The inspector reviewed the FPL Instrument Setpoint Program document. The purpose of the document is to provide the FPL philosophy, management commitment, and description of the Nuclear Engineering Instrument Setpoint Program which includes the following: provisions for documentation of setpoints for safety related instruments and devices, setpoint change and control, and setpoint methodology.

The inspectors examined the current methodology used by FPL for the calculation of setpoints. The licensee employs Nuclear Engineering Department Standard Number IC-3.17, Instrument Setpoint Methodology for Nuclear Power Plants, which is consistent with ISA standard ISA-RP67.04, Part II-1991, draft 9, Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation. The draft ISA standard reflected a reasonable industry consensus for setpoint methodology. Standard IC-3.17 basically implemented the ISA standard. Both Standard IC-3.17 and the ISA standard were written to comply with Regulatory Guide 1.105.

The licensee's program contained treatment of individual uncertainties, combination of uncertainties, and determination of normal trip setpoint and allowable value. Additionally, the

licensee actively participated in the industry group which developed the ISA standard.

The inspectors reviewed IC-3.17 and determined the methodologies contained in the standard were accurate and acceptable to perform the required identification and combination of instrument uncertainties to ensure that vital plant protective features were actuated at appropriate times during transients and accident conditions. The standard provides the necessary methodology to ensure that safety limits defined by the accident analysis would not be exceeded.

The RPS/ESFAS setpoints, which are the most safety significant setpoints, have been calculated using the latest Westinghouse "five column" methodology which closely parallels that of ISA 67.04. Maintenance procedures were written to account for the calculation assumptions. Scaling calculations and a drawing which listed both the process and calibration units were also prepared.

The licensee commissioned an independent review by an I&C systems consultant. The inspector reviewed Turkey Point Setpoint Control Assessment Report dated September 25, 1991. The report was a thorough, critical, and independent look at the licensee's setpoint program. The report identified some strengths, some minor weaknesses, and a few recommendations for improvements. For the identified weaknesses, FPL has initiated corrective action to improve the practices in these areas. Overall the TPNP setpoint control process was evaluated by the consultant as being on par with the rest of the industry and considerably better than most plants of this vintage.

Another objective of the SMI was to determine how FPL insures that the information the existing setpoints were based upon is accurate. The licensee used the following sources:

1. Information verified in Fall of 1988
   - Instrument Index
   - Total Equipment Data Base/Q-List
   - Instrument Calibration Procedures
   - Hagan Loop Drawings
   - PC/Ms
   - Plant Work Orders
   - Selective walkdowns to verify any changes implemented

   This information was re-verified in July, 1991.

2. Numerous walkdowns were performed which included:
   - Environmental Qualification review
   - Regulatory Guide 1.97
   - Rosemount Part 21 on oil loss review

3. Hagan 7100 modules are not physically compatible with components of other vendors and therefore, cannot be intermixed in the RPS cabinets.

4. The licensee performed confirmatory walkdowns on October 30, 1991. These walkdowns included:
   - First stage turbine pressure transmitters (PT-3-474,-484, and -485) were verified to be Rosemount Model 1153GB9. This was consistent with the methodology and resulted in WCAP 12745.
   - Hagan rack for instrument loop P-4-456A (Pressurizer Pressure) was verified to be consistent with methodology and results in WCAP 12745. This confirmed that the loop consisted of four single input comparators, one lead/lag module and a power supply. Model numbers were verified with maintenance instruction 4-PMI-041.69.

The inspectors reviewed applicable portions of Westinghouse WCAP-12201, Westinghouse Setpoint Methodology for Protection System, Revision 1. The revised engineering VCT calculation was performed in accordance with the applicable portions of WCAP-12201 methodology, with modifications for non-safety related control functions. The inspectors concluded that the VCT calculations, as discussed in paragraph 2, had been performed satisfactorily.

The current methodology used by FPL for the calculation of setpoints was inspected to determine if the existing setpoints presented a safety concern. The inspectors reviewed the licensee's independent calculations of various setpoints to see if the differences present a safety concern. While there were some methodology, assumption, and calculational errors; the errors were minor and did not significantly affect the conclusions. The variations were not the result of significant technical differences and were minor enough to not present a safety concern.

The inspectors selected several setpoints and calculated the results independently. The resulting differences between the inspectors' independent calculations and the FPL calculations were within an acceptable band. In each case, the answers reflected a reasonable consensus between the two setpoint calculations and did not present a safety concern.

One aspect of this concern is that the alleger was prematurely removed from the setpoint effort for attempting to extend this methodology to balance of plant equipment such as OMS. As discussed in paragraph 9, the OMS is designed, maintained, and operated as a safety-related system. The methodology used to determine OMS setpoints and pressure/temperature limits comply with the industry and regulatory guidance. The inspectors concurred

with the Westinghouse conclusion that because of the safety margin designed into the current pressure/temperature limit curves, the OMS setpoint uncertainties need not be included in the OMS setpoints. Additionally, the conclusion that the current pressure/temperature limits were valid and that the licensee's OMS setpoint was adequate with respect to the brittle fracture susceptibility at TPNP was accepted by the NRC in the ammendments listed above.

Another objective of the SMI was to inspect the licensee's actions with respect to extending setpoint methodology to BOP. Their program was divided into two basic parts:

1. Placing the safety and non-safety related (including BOP) setpoints into a central setpoint document, and

2. Reconstruction of the setpoint design bases.

The effort to provide a single consolidated Instrument Setpoint Document which contains all setpoints (including design bases), both safety and non-safety related, is considered by the NRC to be an important enhancement and will be followed as IFI 50-250,251/91-45-04, Create a single Instrument Setpoint Document (including design bases).

Entering the safety related and BOP setpoints into the setpoint index drawing will involve several sources of setpoint information. BOP setpoints from controlled plant drawings other than the setpoint index (instrument index, P&IDs, etc.) and setpoints from other sources (FSAR, plant procedures, vendor manuals, vendor documentation, etc.) will be transferred into the setpoint index drawing after an appropriate level of engineering review. This review would in fact be similar to the method in which vendor setpoints were originally placed into plant drawings. As the setpoint index is a drawing controlled by Engineering, the setpoint additions and any other future changes requested by the plant to the contents of the drawing will require a PC/M to evaluate the acceptability of the additions or changes.

The process of reconstructing the design basis of BOP setpoints is designed to include both planned and future activities. Any BOP setpoint calculations which are discovered through the safety-related design basis reconstitution effort (described in the FPL Instrument Setpoint Program document) will be retrieved and entered into the Nuclear Engineering calculation database. The actual setpoint values will also be included in the setpoint index drawing. Recovery of the safety-related design basis information has been prioritized ahead of a BOP effort. Therefore, an evaluation of the needs of a BOP information reconstruction will be made at the conclusion of the safety-related effort.

CONCLUSION: ALLEGATION 10 - NOT SUBSTANTIATED

The FPL setpoint methodology for safety related and balance of plant systems is described in the FPL Instrument Setpoint Program document. Based on standard industry practice the method the licensee was using for safety related and BOP setpoints is acceptable. While it is appropriate that the rigor required for safety related setpoints is not necessary for BOP setpoints, the licensee does have a documented program to collect or recalculate, as necessary, safety related and BOP setpoints (including design bases) on a safety prioritized basis.

11. Questionable engineering practices exist throughout the FPL nuclear program.

DISCUSSION: This allegation is nonspecific and is considered to have been addressed by the inspection of the other allegations in this inspection report.

CONCLUSION: ALLEGATION 11 - NOT SUBSTANTIATED

Based on the results of this team inspection, the existence of questionable engineering practices was not substantiated .

12. MISCELLANEOUS RELAY RACKS (PART 21 NOTIFICATION):

The statement of the concern was as follows:

Miscellaneous cabinets that contain relays or other components that may perform safety and critical control functions [Part 21 Notification]. These cabinets don't satisfy electrical separation criteria or seismic qualifications.

With respect to electrical separation criteria the team reviewed whether or not the plant meets the electrical and physical separation requirements imposed on safety-related circuits. Focusing on miscellaneous relay racks QR 46 and QR 47 for both units, the design basis separation criteria was compared to the actual installation. In addition, the licensee's safety evaluation for a 10 CFR 21 report, JPN-PTN-SENP-91-006, Safety Evaluation for Safety Functions in Miscellaneous Relay Racks, was reviewed; because it had a bearing on QR 46 and QR 47.

The inspector walked down the subject relay racks which are located in the control room behind the main control panel. They were furnished by Westinghouse Electric Corporation as part of the original plant equipment. QR 46 and QR 47 are side by side within one six feet wide by six feet high structure. They have one and one half feet deep relay compartments in a back-to-back configuration. There are front and back hinged doors. The structure is of formed heavy gauge sheet metal, bolted together and welded to a base which is securely bolted in place. External wiring enters through an opening in the top and conduits through the bottom. The miscellaneous relay racks contain 120 Volts AC, 120 Volts DC and 125 Volts DC auxiliary relays with instantaneous contacts. Each cabinet contains one timing relay, terminal blocks, fuses, and wireways. The relays in QR 46 and QR 47 are used as annunciator relays (i.e., to provide a dry contact to the plant annunciator) and for control logic functions. Approximately 68 of the 540 relays are required to have safety related type qualification and the remainder are non-safety related. All the relays must have some type of seismic qualification. None of the relays were part of the RPS.

A report submitted by Westinghouse Electric Corporation pursuant to 10 CFR Part 21, presented some possible generic problems with miscellaneous relay racks, and it therefore applied to QR 46 and QR 47. The Part 21 report was submitted to the NRC on June 24, 1991, and issued to the site on July 18, 1991. The report stated that the miscellaneous relay racks were not furnished as safety-related or seismically qualified. However, it had come to the attention of Westinghouse Electric Corporation that a few plants (TPNP was not mentioned) were using relays in these racks for safety related functions, had routed non-safety related cables emanating from the racks together with safety related cables outside the racks, or had inadvertently mixed safety related and non-safety related wires inside the racks. The licensee had performed evaluations and continues to perform evaluations to address the potential problems raised in the Part 21 report. The team reviewed these evaluations and the planning document for ongoing work.

The relevant requirements may be summarized as follows:

- As stated in FSAR section 8.2.2, power and control circuits to the duplicate equipment are routed in separately located cable trays, ducts, conduits, etc., with one foot approximate separation (horizontal and vertical) between raceways.

- Redundant safety related and non-safety related circuitry shall be electrically separate.

- It is <u>not</u> a requirement to provide physical separation (other than normal construction) between safety related and non-safety related cables in raceways.

- It is <u>not</u> a requirement to provide special separation between wires associated with redundant safety related devices and non-safety related devices within cabinets.

As part of addressing the Part 21 concerns, the licensee had determined that QR 46 and QR 47 were seismically qualified by using valid analytical techniques. This analysis was reviewed by the team. Where arguments of similarity were made, the similarity was confirmed by on-site inspection. The great majority of relays were qualified by testing. A few relays were determined to be seismically qualified by using industry accepted procedures for older plants. The team also noted that a previous inspection (NRC Inspection Report Nos. 50-250,251/89-203) had addressed the seismic adequacy of the miscellaneous relay racks and found it acceptable.

With respect to the MRR qualification, the inspectors reviewed Calculation No. PTN-BFJC-91-009, Rev. 0, for seismic qualification of the MRRs, including the sheet metal cabinets, internal mounting, devices located within the cabinets, and cabinet anchorage-to-ground. This calculation was generated by the licensee to evaluate the seismic adequacy of MRR Nos. 3QR46, 3QR47, 4QR46, and 4QR47 in response to letter No. FPL-91-587, July 18, 1991, from Westinghouse Electric Corporation. The letter informed the licensee that Westinghouse Letter NS-NRC-91-3603 to NRC, dated June 24, 1991, had identified this issue as a potential Part 21 Report. The letters described the potential for the existence of a substantial safety hazard concerning the installation of the safety related equipment in non-safety related relay racks.

The licensee's engineers performed walkdown inspections and recorded physical description and installation information about the above four racks as well as two safety related RPS Racks, 3QR33 and 4QR33, for comparative purposes. The safety related racks were seismically qualified by Westinghouse previously. The two sets of racks are essentially the same except for the presence of plastic channels for the routing of wiring and only 56 relays on the racks for 3QR33 and 4QR33, while the set of non-safety related racks have no plastic channels and 80 relays on the racks. The weight difference for the two sets of relays is only 46 pounds for each face of a fully-loaded panel. The above load increase for the non-safety related racks is very small compared to the total weight or load of the entire cabinet. The peak seismic factor for the safety-related rack is eight percent higher than the non-safety related racks, due to different locations and elevations in the control building. The higher seismic factor of the safety related racks offsets the weight increase in the non-safety related racks. The calculation also qualified the cabinet anchorage-to-ground based on the comparison of the various testing data performed by Electric Power Research Institute and the judgment of the experienced walkdown personnel. The licensee provided a supplemental anchorage-to-ground calculation to NRC on November 8, 1991. The supplemental calculation demonstrated that the three-

eighths inch diameter redhead anchor bolts which anchored the cabinet to the ground were sufficient to resist the cabinet overturning during an earthquake based on the total cabinet weight and seismic factor. The licensee will make this a formal calculation to document the additional evaluation of the anchorage-to-ground. Two main references used in the calculation are: Westinghouse Document WCAP-7817, (December, 1971), Seismic Testing of Electrical and Control Equipment (Low Seismic Plants); Electric Power Research Institute Document No. NP-7148-M, Procedure for Evaluating Nuclear Power Plant Relay Seismic Functionality, December, 1990. Based on the licensee walkdown inspections, evaluation, and comparison, the calculation is acceptable and MRR is considered to be seismically qualified.

Since the racks and relays were qualified, it was acceptable that some of the relays be used for safety related functions. The team made spot checks of the routing of external safety related cables emanating from the miscellaneous relay racks and found that the above mentioned requirement for separation was met.

The licensee is in the process of performing a study of 100% of circuits that contain devices or wiring in the miscellaneous relay panels. The study will address specifically whether or not annunciator circuits are electrically separate from the RPS power supply. The study will also review the routing of safety related cables emanating from QR 46 and QR 47 to confirm that the separation criteria is maintained. At the time of the inspection, the study was about 65% complete with no problems having been identified. The licensee stated that the study is proceeding at a pace that would guarantee completion before March 15, 1992. NRC will review the final results of this study, IFI 250,251/91-45-05, MRR annunciator circuit relays separation from RPS power supply.

This allegation also questioned the credibility of 10 CFR Part 50.59 evaluations. One issue raised as part of this concern was that the Nuclear Engineering Lead Team Meeting Minutes dated September 3, 1991, made a statement, which may be contrary to 10 CFR Part 50.59, as follows:

> Design Defense means defending the design until it is proven wrong. If the design is wrong it will be modified.

The inspectors obtained the following clarification of this statement from the Director, Nuclear Engineering, FPL, on October 30, 1991:

> Bring me the design basis and show me where it is wrong. If the design can be proven to be wrong, then it will be modified. If it can not be shown where the design is wrong, then the design is defensible.

The inspectors determined that the above statements are not contrary to 10 CFR Part 50.59.

The following evaluations were inspected by the team to determine the adequacy of the licensee's 10 CFR 50.59 evaluations. The inspectors reviewed the 10 CFR 50.59 evaluation performed to evaluate the lowering of low pressure Safety Injection Safety Analysis Limit. The evaluation satisfactorily addressed the change to the plant as described in the FSAR. The evaluation was complete and factual.

The inspectors reviewed the 10 CFR 50.59 evaluation performed to evaluate the VCT level switch replacement which was contained in PC/M 91-037 and PC/M 91-038. The evaluation satisfactorily addressed the 10 CFR 50.59 criteria. The evaluation was complete and factual.

The inspectors reviewed the 10 CFR 50.59 evaluation performed to evaluate the upgrade of the conductivity sample system for steam generator blowdown, condensate pump discharge, feedwater, and condenser hotwell which was contained in PC/M 90-342. The modification was not safety related. However, portions of the system were designed for seismic 2 over 1 concerns. The evaluation satisfactorily addressed the 10 CFR 50.59 criteria. The evaluation was complete and factual.

The inspectors reviewed the 10 CFR 50.59 evaluation performed to evaluate the Generic Letter 89-10, Motor Operated Valve Enhancements, which were contained in PC/M 91-004. The modification involved the modification and/or additions to safety related Limitorque valve actuators for the following motor operated valves: MOV-3-626, Reactor Coolant Pump Thermal Barrier; MOV-3-744A/B Residual Heat Removal/Low Head Safety Injection Pump Discharge Isolation; MOV-3-1400, Main Steam Isolation Valve Bypass Isolation; MOV-3-1401, Main Steam Isolation Valve Bypass Isolation; MOV-3-1402, Main Steam Isolation Valve Bypass Isolation; 3-MOV-1420 Steam Generator Feedwater Pump Discharge Isolation; 3-MOV-1421 Steam Generator Feedwater Pump Discharge Isolation; MOV-3-866A/B, High Head Safety Injection to Hot Leg Isolation; and MOV-0-878A/B, Safety Injection Cross-tie Isolation. The modifications replaced or upgraded various components in the valve actuators to ensure the motor operated valves would perform their intended safety functions during the maximum expected differential pressure conditions. The evaluation satisfactorily addressed the 10 CFR 50.59 criteria including Technical Specification changes. The evaluation was complete and factual.

The inspectors reviewed the 10 CFR 50.59 safety evaluations performed for PC/Ms 90-331 and 90-332, "C" Bus Transformer Deluge System "Power Available" Light. These PC/Ms involved installing a power available light to the "C" Bus Transformer Deluge System Control Panel (4C 259) which will permit visual indication of power

available to the deluge controls. The deluge system requires 120 volts AC power to operate automatically. The PC/Ms were determined to be quality related because they involved modifications to the fire protection system. The safety evaluations were complete, factual, and adequately addressed the 10 CFR 50.59 criteria.

The inspectors held discussions with licensee personnel concerning their efforts to improve the overall quality of engineering design outputs and services. One effort involves technical assessments, performed by the Engineering Assurance Section within JPN, of FPL architect engineers and contractors, including the Production Engineering Group within JPN. One of the areas reviewed within Production Engineering Group was PC/Ms, which included the assumptions and design inputs used in applicable 10 CFR 50.59 safety evaluations. The review of selected PC/Ms is performed by the Discipline Chiefs. The review may include the applicable design engineer being called upon to "defend" the various assumptions and design inputs included in the 10 CFR 50.59 safety evaluation. This effort is intended to identify potential weaknesses and verify the overall technical adequacy of the 50.59 safety evaluations.

In addition to the above 10 CFR 50.59 safety evaluations, PC/Ms and applicable 10 CFR 50.59 safety evaluations were also reviewed and discussed in NRC Inspection Report Nos. 50-250,251/91-32. After reviewing selected 10 CFR 50.59 safety evaluations during this inspection and during the inspection documented in the above inspection report, the inspectors found that, while there were a few weaknesses identified for specific 10 CFR 50.59 safety evaluations, the licensee's overall program was adequate.

CONCLUSION: ALLEGATION 12 - NOT SUBSTANTIATED

Inadequate evaluation of the MRR was not substantiated. The licensee was appropriately evaluating the 10 CFR Part 21 report. The MRRs have been seismically qualified. The team made spot checks of the routing of external safety related cables emanating from the MRRs and found that they met the previously described standard electrical separation requirements. FPL has an ongoing study of the MRR relays to verify that electrical separation criteria is met inside the cabinet. No safety problems have not been identified to date. The study is scheduled to be completed by March 31, 1992. NRC will review the final results of this study, IFI 50-250,251/91-45-05, MRR annunciator circuit relays separation from RPS power supply. For those 10 CFR 50.59 safety evaluations reviewed, a safety concern with respect to the 10 CFR 50.59 program was not substantiated.

13. GRAVE DEFICIENCIES IN PLANT CONFIGURATION:

The statement of the concern was as follows:

GRAVE DEFICIENCIES IN PLANT CONFIGURATION AND IN THE COHERENCE OF THE FPL ENGINEERING SUPPORT ORGANIZATION

DISCUSSION: This allegation was made with respect to the Eagle 21 system. The detailed concerns identified by the alleger were previously identified by the licensee and were being inspected by the NRC prior to receiving the alleger's letter. The results of the initial inspection are documented in NRC Inspection Report Nos. 50-250,251/91-42. The Allegation Team Inspection continued the inspection into the Eagle 21 configuration control concern and are closing the following unresolved item: (Closed) URI, 50-250,251/91-42-02, Followup on non-plant specific settings in Eagle 21 portion of the RPS.

The licensee contracted with the NSSS supplier to furnish an upgrade system which is a microprocessor-based functional replacement for the originally installed analog process protection equipment. This system is called Eagle 21. The system was developed by the NSSS for application on any of the nuclear power systems which it has manufactured. WCAP - 12858 was issued which documents the implementation of the Eagle 21, Replacement Hardware Design, Verification and Validation Plan, as applied to Turkey Point Units 3 and 4. The Eagle 21 portion of the process instrumentation includes all necessary devices for the functional replacement of the existing analog process protection equipment used to monitor process parameters and initiate actuation of the reactor trip and engineering safeguards systems except the transmitters, indicators, and recorders.

The system processes the protection and monitoring channels for:

A. T_{ave} and Delta T

B. Pressurizer Water Level

C. Reactor Coolant Wide Range Temperature (Monitoring only)

Since this system is a programmable processor the various plant parameters were programmed into the system. The supplier used information available from other sources (generic) and set points which were supplied by the licensee. The NSSS performed pre-shipment factory testing of the system at the point of manufacture using generic programmable constants based on the information that was available to them. They then installed the system at the site and performed on-site startup tests still using the generic constants.

On September 27, 1991, the licensee was performing procedure 3-OSP-059.4, Power Range Nuclear Instrumentation Analog Channel Operational Test, in preparation for low power physics testing on Unit 3. During this test, the PSN observed that the Overpower Delta T meter for RPS channel 2 responded to a delta flux test signal from power range channel N42, when it should not have. Further investigation determined that incorrect constants for Overpower Delta T calculations had been left in the newly installed Eagle 21 system. This problem was verified to not exist on the other similar channels on Unit 3 and those on Unit 4.

A pre-operational test had been conducted to test all functions of the system, regardless of intended use. Thus, constants to test the delta flux function of Overpower delta T were installed during the preoperational test. The procedure required that plant specific constants be installed following the preoperational test, but that was not accomplished for channel N42, and a non-zero constant remained for the delta flux function. The licensee's calibration and surveillance procedures did not test the delta flux function in the Overpower Delta T circuits, because it was not expected to exist (i. e. tuning constants set to zero). Thus, detection of the Overpower Delta T response to a change in delta flux was the result of an alert operator who recognized an inappropriate and unexpected response. The existence of the delta flux function is not a safety concern because it conservatively reduced the trip set point for all extreme values of delta flux. However, the existence of an incorrect constant in the Eagle 21 system was a concern. The licensee conducted a review of all constants in Eagle 21 as a result of this observation. Four constants affecting the output of two RTDs by about 0.10 degrees F each were found to be in error. Three constants of overpower turbine runback were found to be 1.12 degrees F before the trip setpoint instead of the desired 1.50 degrees F. The span of the three Delta T lead-lag circuits was found to be 150 degrees F, which was inconsistent with the 75 degrees F span used in the remainder of the Delta T circuits. This inconsistency did not affect the rate output of the circuit. The licensee performed several safety evaluations, which were reviewed by the inspectors, in order to determine the safety impact of the above conditions. In perspective, over 600 constants were reviewed; 10 were discrepant, and none of the discrepancies adversely affected the performance of the protective circuits and the Eagle 21 system remained operable.

On October 5, 1991, with Unit 3 in Mode 1 at 50% power, the licensee was performing the planned Incore/Excore detector calibration at the 50% power plateau. This calibration is routinely performed both during post refueling power ascensions and quarterly during the cycle. When attempting to input the calculated scaling factor (G-Factor) for Overtemperature Delta T, the inputs were not accepted by the Eagle 21 system. The calculated factors were approximately 3.2, and the system would not

accept a scaling factor of greater than 3.0 which was not sufficient to obtain the required gain for the delta flux functions. The licensee held the unit at 50% power, evaluated the safety of continued operation, and began an investigation into the root cause. This problem required the replacement of a programmable chip (EPROM) which was subsequently provided by Westinghouse, and the system was satisfactorily calibrated prior to continued power ascension.

This condition was reviewed by safety evaluation JPN-PTN-SEFJ-91-039, Revision 0, Safety Evaluation to Allow Operation at Nominal 50 Percent Power with Eagle 21 G-Factor Limitation (Turkey Point Unit 3). The safety evaluation concluded that no unreviewed safety questions existed and that the plant was operating within its TS. The evaluation also concluded that continued operation at or below 50% power until calibration of the Overtemperature Delta T trip setpoint was changed was acceptable because the review of design bases events concluded that the power range trip, which was set at 80% power, would be actuated earlier than the Overtemperature Delta T trip providing the required protection. Performance of this calibration at 50% power with the power range trip set at 80% power, is the result of administrative controls designed to prevent the plant from operating outside its design basis. This calibration must be completed prior to the power range trip setpoint being set above 80%. The Westinghouse conclusion that the power range trip would actuate before an Overtemperature Delta T temperature provided the industry bases for allowing plants to perform the subject calibrations during the normal power ascension procedure at reduced power. The safety evaluation also stated that when the axial flux is maintained within band (where the band is between -14% and +10% flux difference), there is no contribution from the delta flux function to the Overtemperature Delta T trip setpoint.

On October 7, 1991, with Unit 3 at 50% of rated power, during calibration of the new digital instrumentation rack (Eagle 21) the Delta T Subzero factor used in calculating Overpower Delta T and Overtemperature Delta T by setpoint formula was found to be set at the design value of 56.1 degrees F in lieu of the indicated value as required by TS. TS 2.2.1 requires that indicated values of Delta T at rated thermal power be used for Delta T Subzero in the calculation of Overpower Delta T and Overtemperature Delta T. A review of the operational history at TPNP prior to the RTD bypass elimination modification (accomplished during the 1991 dual unit outage) revealed that indicated Delta T at rated thermal power has been as low as 53.8 degrees F. Presently, the indicated values of Delta T at rated thermal power are (in degrees F) as follows:

Loop Delta T	A	B	C
Unit 3	51.87	51.98	52.38
Unit 4	52.52	53.22	52.73

The licensee performed a detailed safety analysis to assess the safety significance of the use of the Delta T design value of 56.1 degrees F for Delta T Subzero in the setpoints for Overpower Delta T and Overtemperature Delta T. The result of this analysis indicated that the affected parameters for DNB and peak linear heat rate remained within the analyzed design basis for both units. The licensee as part of the safety evaluation determined that power operation could continue up to 75% reactor power using the design Delta T value. Using the safety evaluation as a basis for continued operation, the licensee proceeded to escalate to 75% power on October 12, 1991 and completed entering the indicated Delta T for Delta T Subzero on October 14, 1991. This same approach was used for Unit 4 which went critical on October 27, 1991 and reached 75% power on November 3, 1991, at which time the Unit 4 indicated Delta T was entered in place of the design Delta T. TS 2.2.1 requires reactor trip system instrumentation and interlock setpoints be set consistent with the trip setpoint values shown in Table 2.2-1. In TS Table 2.2-1, Overtemperature Delta T refers to Note 1, and Overpower Delta T refers to Note 3. Table 2.2-1 Note 1 and Note 3, both define Delta T Subzero as the indicated Delta T at rated thermal power. The use of the design Delta T (56.1 degrees F) in lieu of the indicated Delta T for computing Overpower Delta T and Overtemperature Delta T, was non-conservative and a violation of TS 2.2.1 and will be tracked as VIO 50-250,251/91-45-03, Failure to use the correct Delta T Subzero for calculation of the Overtemperature Delta T and Overpower Delta T setpoints.

This condition was reviewed and documented in safety evaluation JPN-PTN-SEFJ-91-40, Evaluation of Delta-T Subzero Used in Overtemperature Delta T and Overpower Delta T Reactor Protection Setpoints. The review of the Delta T setpoints, by the licensee and NSSS vendor, confirmed that a 10 degree F margin existed for the setpoints, without violating DNBR and linear power density limits. The 2.3 degree maximum recorded error in the setpoint was well within that bound. Furthermore, the 10 degree F margin yields a tolerable overpower trip setpoint of 118% RTP, which bounds the error-induced setpoint of 114% RTP.

During the NRC review of the safety evaluation JPN-PTN-SEFJ-91-40, the following arguments were considered but given no weight in support of the above conclusion.

The argument that the actual RCS flow is greater than that used in the analysis by virtue of the measured Delta T being less than the calculated Delta T was not a justifiable conclusion. It is well known that the flow in the hot legs of this class of reactors is not well mixed and that the measured hot leg temperature is not the mixed mean temperature. That situation prevails whether the hot leg temperature is measured in bypass loops or by direct immersion RTDs. Furthermore, other reactors have experienced an increase in the apparent hot leg temperature after removal of the bypass loops. At TPNP, apparent hot leg temperature decreased after removal of the bypass loops and installation of the RTDs in thermal wells within the hot legs proper. Since the wells replaced the scoops for the bypass loops, it is possible that the hydraulics of this facility favor measuring the cooler portions of the flow stream.

The argument that the hot channel factors for this facility have been constant over time is not correct. It is true since replacement of the steam generators in approximately 1982, but, during operation with the original steam generators with a high percentage of tubes plugged, the hot channel factors were much more restrictive. At the same time, the measured Delta T Subzero may have been closer to the setpoint by virtue of reduced flow through the plugged steam generators. While the hot channel factors for this facility have not been constant over time, NRC concluded, that further review of the history of TPNP operation prior to 1982 was not warranted.

Even with the above weaknesses in the safety evaluation, the conclusion that no unresolved safety question was created by the error and that the plant was operated within its design bases is acceptable based upon the 10 degree F margin for the setpoints.

Additionally, the following safety evaluations were reviewed by the team and the conclusions were found to be acceptable.

JPN-PTN-SEIS-91-077 Rev. 0	Turkey Point Unit 3 Engineering Evaluation for the Verif. of Programmable Parameters for the Eagle 21 Protection Racks
JPN-PTN-SEIS-91-077 Rev. 1	Turkey Point Units 3 & 4 Engineering Evaluation for the Verif. of Programmable Parameters for the Eagle 21 Protection Racks
JPN-PTN-SEIS-91-081 Rev. 0	Turkey Point Units 3 & 4 Engineering Evaluation for Eagle 21 Tuning Constant DELTAH

JPN-PTN-SEIS-91-083 Rev. 0	Turkey Point Units 3 & 4 Engineering Evaluation for Deadband of OTDT and OPDT Eagle 21 Setpoints
JPN-PTN-SENS-91-086 Rev. 0	Turkey Point Unit 3 Safety Assessment for Eagle 21
JPN-PTN-SEIS-91-090 Rev. 0	Turkey Point Unit 3 Safety Evaluation for Connection of Test Equipment to an Operational Eagle 21 Channel
JPN-PTN-SEIS-91-093 Rev. 0	Turkey Point Units 3 & 4 Safety Evaluation for Overtemperature and Overpower Delta Temperature for Turbine Runback Setpoint

The inspectors reviewed Quality Instruction JPN-QI-8.3, Item Equivalency Evaluations, to determine the licensee's requirements for the replacement of the EPROMs in the Eagle 21 system to allow proper calibration and allow the system to increase power. The evaluation JPNS-PTN-91-2152, Rev 1, appeared to comply with the requirements of the QI-8.3 for verifying that the replacement parts would have no impact on the safety analysis and would not reduce the margin of safety as defined in the Technical Specifications. The evaluation also verified that the EPROMs were acceptable alternates to the originals and with the new range would improve the items ability to perform their function within the system. The form and fit of the replacement EPROMs were not changed.

The root cause investigation into both of the above problems included a complete review of the interchange of information between the vendor and FPL. It was determined that the shared responsibilities between the vendor and FPL failed to ensure that unit specific calibration data was exchanged and verified and the divided testing responsibilities did not provide for the proper exchange of the information critical for the programming of the Eagle 21 system. The communications between the vendor and FPL project managers were not logged; therefore no tracking or follow-up to closure of these communications could be performed. A contributing cause to this event was that the level of technical understanding within FPL Engineering and I&C Maintenance of the Eagle 21 system design was not sufficient to recognize the lack of adequate test or calibration procedures prior to returning the system to service. Additionally, the inspectors determined that the lack of one consolidated instrument setpoint document contributed to this problem.

10 CFR Part 50, Appendix B, Criterion III, Design Control, states in part, that design control measures shall provide for verifying and checking the adequacy of design,...be established for the identification and control of design interfaces and for

coordination among participating organizations. Florida Power and Light Company's implementing Quality Instruction, QI 3-PTN-1, Design Control, requires that design control measures shall provide for verifying or checking the adequacy of design, such as by performance of design reviews or by performance of a suitable testing program.

Contrary to the above, adequate controls were not in place during the exchange of engineering data between the vendor and the Florida Power and Light Company staff to insure that complete and accurate programmable constants and programmable components were installed in the Eagle 21 system in that between September 27 and October 5, 1991, the licensee identified that the Eagle 21 system contained non-plant specific settings in the Eagle 21 portion of the Reactor Protection System (Tuning Constants, Resistance Temperature Device constants, and Scaling Factor) that were not acceptable for proper operation of Overpower Delta T and Overtemperature Delta T. This is identified as a violation and will be tracked as VIO 50-250,251/91-45-02, failure to maintain adequate design control of the Eagle 21 system.

With respect to configuration control, discussions were held with the licensee to determine what controls existed for insuring that contractors were meeting the contractual obligations set forth in engineering specifications. This inquiry was made as the result of the deficiencies identified in controlling the configuration of the Eagle 21 system. The licensee advised that the contract for the Eagle 21 system was issued for a complete package, that is the design, engineering approval, equipment check out at the factory, field installation of the equipment, and field testing (Pre-operational tests). The vendor was responsible for the entire package until the time that startup and operational testing was to start.

The licensee advised that this and the RPS setpoints submittal were the only contracts that were not processed through either their AE or the FPL engineering department. In the contract for the sequencers the AE and FPL engineering sections worked together to insure that the programs were correct and that drawings and equipment were correctly configured. This was also true with the emergency diesel generators. The testing at the site bore out that there were no program deficiencies in the program portion of the sequencer. There were some hardware problems identified. In one case the day tank refill valve circuit was found to be inadequate due to a manufacturers design error. Manufacturing defects were identified which resulted in the replacement of all the relays in the sequencer and in the removal of permanent magnet generator which was furnished with the new Unit 4 emergency diesel generators for black start purposes.

CONCLUSION: ALLEGATION 13 - NOT SUBSTANTIATED

It was concluded that, while two violations were identified, the instances described above did not constitute a programmatic design/configuration control breakdown and, consequently, grave deficiencies in plant configuration were not substantiated.

14. EXIT MEETINGS

On November 1, 1991, the team inspection effort at the FPL Corporate offices in Juno Beach was completed. At that time the Team Leader informed the licensee of the preliminary inspection results to date.

On November 18, 1991, the Regional Administrator and the Team Leader conducted an exit meeting at the FPL Corporate site in Juno Beach. The licensee and NRC personnel attending this meeting are listed in Appendix C. The licensee did not provide to the team any materials identified as proprietary. During the exit, the team summarized the scope and findings of the inspection as indicated below. There were no dissenting comments from the licensee on the findings.

CONCLUSION: Inspection of the thirteen allegations resulted in the following:

11 - NOT SUBSTANTIATED
1 - NOT INSPECTED (EEOC JURISDICTION)
1 - PARTIALLY SUBSTANTIATED

The following allegation was determined to be partially substantiated:

Management's decision to postpone, due to budgeting or other constraints, important modifications such as the correction of the Power Mismatch Circuits

Each modification which was postponed during the DUO at TPNP was determined to not impact plant safety. Evidence was not found that would substantiate an overall atmosphere of intimidation, coercion, or harassment.

FINDINGS: Within the scope of this inspection one non-cited violation, two cited violations, and two inspector followup items were identified.

Item Number	Description and Reference
50-250,251/91-45-01	NCV - Failure to implement adequate design integration (paragraph 4)
50-250,251/91-45-02	VIO - Failure to maintain adequate design control of the Eagle 21 system (paragraph 13).
50-250,251/91-45-03	VIO - Failure to use correct Delta T Subzero for calculation of the Overtemperature Delta T and Overpower Delta T setpoints (paragraph 13).
50-250,251/91-45-04	IFI - Create a single Instrument Setpoint Document (including design bases)(paragraph 10).
50-250,251/91-45-05	IFI - MRR annunciator circuit relays separation from RPS power supply (paragraph 12).

APPENDIX A

ABBREVIATIONS AND ACRONYMS

AC	Alternating Current
ADM	Administrative Procedure
AE	Architectural Engineer
AFW	Auxiliary Feed Water
APSN	Assistant Plant Supervisor Nuclear
ASLAB	Atomic Safety and Licensing Appeals Board
BOP	Balance of Plant
CCW	Component Cooling Water
CFR	Code of Federal Regulation
CNRB	Corporate Nuclear Review Board
CRN	Change Request Notice
CVCS	Chemical and Volume Control System
DC	Direct Current
DCR	Drawing Change Request
DCRDR	Detailed Control Room Design Review
DCTS	Drawing Change Tracking System
DEEP	Design Equivalent Engineering Package
DNB	Departure from Nucleate Boiling
DNBR	Departure from Nucleate Boiling Ratio
DUO	Dual Unit Outage
ECCS	Emergency Core Cooling System(s)
EEOC	Equal Employment Opportunity Commission
EOOS	Equipment out of Service
EOP	Emergency Operating Procedure
EP	Engineering Package
EPRI	Electric Power Research Institute
EPROM	Erasable Programmable Read Only Memory
EPS	Emergency Power System
ERDADS	Emergency Response Data Acquisition Display System
ESFAS	Emergency Safeguards Feature Actuation System
F	Farenheit
FFD	Fitness For Duty
FPL	Florida Power and Light
FSAR	Final Safety Analysis Report
GET	General Employee Training
HED	Human Engineering Deficiency
Hz	Hertz
I&C	Instrumentation and Control
IE	Inspection and Enforcement
IEE	Item Equivalency Evaluation
IFI	Inspector Followup Item
IR	Inspection Report
I/S	Integrated Schedule
ISA	Instrument Society of America
Kv	Kilo-volt
LOCA	Loss of Coolant Accident
ma	Milli-amp
MCC	Motor Control Center
MEP	Minor Engineering Package
MMPI	Minnesota Multi-Phasic Personality Inventory

ABBREVIATIONS AND ACRONYMS continued:

MOD	Modification
MOV	Motor Operated Valve
MRR	Miscellaneous Relay Rack
MSIV	Main Steam Isolation Valve
MWe	Megawatt Electric
NCR	Nonconformance Report
NCV	Non-Cited Violation
NDTT	Nil Ductility Transition Temperature
NIS	Nuclear Instrumentation System
NNSR	Not Nuclear Safety Related
NOP	Normal Operating Procedure
NR	Narrow Range
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSR	Nuclear Safety Related
NSSS	Nuclear Steam System Supplier
N-2	Nitrogen
OMS	Overpressure Mitigation System
ONOP	Off Normal Operating Procedure
OOS	Out of Service
ORAT	Operational Readiness Assessment Team
OSM	Outside Services Management
OSP	Operations Surveillance Procedures
Q_N	Nuclear Power
Q_T	Turbine Load
PC/M	Plant Change/Modification
PEG	Production Engineering Group
P&ID	Piping and Instrumentation Diagram
PLA	Proposed License Amendment
PM	Preventive Maintenance
PMT	Post Maintenance Testing
PNSC	Plant Nuclear Safety Committee
PORV	Pressure Operated Relief Valve
PRA	Probabilistic Risk Assessment
PSIG	Pounds per Square Inch Guage
PSN	Plant Supervisor Nuclear
PT	Pressure Transmitter
PWO	Plant Work Order
QI	Quality Instruction
QR	Quality Related
RAI	Request for Additional Information
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REA	Request for Engineering Assistance
RHR	Residual Heat Removal
RPI	Rod Position Indication
RPS	Reactor Protection System
RTD	Resistance Temperature Device
RTP	Rated Thermal Power
RWST	Refueling Water Storage Tank

ABBREVIATIONS AND ACRONYMS continued:

SALP	Systematic Assessment of Licensee Performance
SATS	System Acceptance Turnover Sheet
SER	Safety Evaluation Report
SG	Steam Generator
SGFW	Steam Generator Feed Water
SI	Safety Injection
SMI	Setpoint Methodology Inspection
SPDS	Safety Parameter Display System
SR	Safety Related
T_{ave}	Average RCS Temperature
T_{ref}	Reference RCS Temperature
TE	Temperature Element
TEDB	Total Equipment Data Base
TPNP	Turkey Point Nuclear Plant
TS	Technical Specifications
TSA	Temporary System Alteration
UF	Underfrequency
URI	Unresolved Item
V	Volt
VCT	Volume Control Tank
VIO	Violation

APPENDIX B

DOCUMENTS REVIEWED (PARTIAL LISTING)

NUMBER	TITLE
ADM-101	Procedure Writers Guide
IC-3.17	FPL Nuclear Engineering Department Standard, Instrument Setpoint Methodology for Nuclear Power Plants
ISA 67.04	
JPN-PTN-SEIJ-91-008	Plant Maintenance Instructions, 10 CFR 50.59 Recommended Procedure Changes
JPN-PTN-SENP-91-006	Safety Evaluation for Safety Functions in Miscellaneous Relay Racks
JPN-PTN-SEIS-91-077 Rev. 0	Turkey Point Unit 3 Engineering Evaluation for the Verif. of Programmable Parameters for the Eagle 21 Protection Racks
JPN-PTN-SEIS-91-077 Rev. 1	Turkey Point Units 3 & 4 Engineering Evaluation for the Verif. of Programmable Parameters for the Eagle 21 Protection Racks
JPN-PTN-SEIS-91-081 Rev. 0	Turkey Point Units 3 & 4 Engineering Evaluation for Eagle 21 Tuning Constant DELTAH
JPN-PTN-SEIS-91-083 Rev. 0	Turkey Point Units 3 & 4 Engineering Evaluation for Deadband of OTDT and OPDT Eagle 21 Setpoints
JPN-PTN-SENS-91-086 Rev. 0	Turkey Point Unit 3 Safety Assessment for Eagle 21
JPN-PTN-SEIS-91-090 Rev. 0	Turkey Point Unit 3 Safety Evaluation for Connection of Test Equipment to an Operational Eagle 21 Channel
JPN-PTN-SEIS-91-093 Rev. 0	Turkey Point Units 3 & 4 Safety Evaluation for Overtemperature and Overpower Delta Temperature for Turbine Runback Setpoint
JPN-91-0094	

QI 3.1	Design Control
QI 3.1-3	Engineering Package (EP)
QI 3.1-7	Design Integration
QI 3.2	Design and Safety Analyses
QI 3.11	NRC Submittals
QI 6.7	Engineering Evaluations
3/4-PMI-041.10	RCS Subcooling Margin Monitoring Train B Calibration
3/4-PMI-041.17	T_{ave} to Rod Speed Control and Power Mismatch
3/4-PMI-041.22	Reactor Coolant Pressure, Wide Range, P-3-405 Channel Calibration
3/4-PMI-041.39	1RCS PORV Actuator Overhaul/Maintenance, PCV-*-455C & PCV-*-456
3/4-OSP-041.4	Overpressure Mitigating System Nitrogen Backup Leak and Function Test
4-OSP-059.4	Power Range Nuclear Instrument Analog Channel Operational Test
PC/M 83-88,89	Deletion of Flux Rate Input to Turbine Run Back
PC/M 84-208,209	Reinstatement Power Mismatch Circuits Without Automatic Rod Withdrawal
PC/M 81-13,14	Deletion of Power Mismatch Circuitry from the Rod Control System
PC/M 75-81	Nil Ductility Transition Temperature (NDTT) Control
PC/M 78-27,28	Overpressure Mitigation System (OMS) - Permissive Status Panel Light and Annunciator Interlocks
PC/M 78-16,17	Pressurizer PORV's Backup N-2 Supply; PC/M 78-23,24, OMS Test Switch and Relabel OMS Components
PC/M 81-162,167	Installation of Inadequate Core Cooling System Instrumentation
PC/M 86-50	Nitrogen Backup Supply Pressure Regulator Replacement for OMS
PC/M 88-396,399	PORV Diaphragm Replacement and Lockwasher Addition
PC/M 88-427,535, 565	Pressurizer PORV Air and Nitrogen Supply Tubing Enhancements.
PC/M 83-88,89	Deletion of Flux Rate Input to Turbine Run Back
PC/M 84-208,209	Reinstatement Power Mismatch Circuits Without Automatic Rod Withdrawal
PC/M 84,211	Turbine Runback Modifications
PC/M 90-301	Modification for WEJ-IT resolution-Main Steam System
PC/M 90-304,305	Modification of Main Steam Dump Line Structure-WEJ-IY Resolution

PC/M 90-331,332	"C" Bus Transformer Deluge System "Power Available" Light
PC/M 90-342	Upgrade of Hotwell Sample System
PC/M 90-508,509	Implementation of Setpoint Methodology
PC/M 91-004	MOV Enhancements Generic Letter 89-10
PC/M 91-037,038	Modifications in L-3-112 and L-3-115 Loops
PTN-BFJI-91-005	Setpoint Calculation for VCT Level Transmitters Loop, Revision 0
WCAP 12201	Bases Document for Westinghouse Setpoint Methodology for Protection Systems
WCAP 12745	Westinghouse Setpoint Methodology For Protection Systems - Turkey Point Units 3 and 4 - Florida Power and Light Company
	Plant Engineering Group (PEG) Training Manual on Turkey Point Setpoint Methodology, Rev 0, February 1991

APPENDIX C

EXIT ATTENDANCE

1. Licensee Employees at Exit on November 1, 1991

J. H. Goldberg, President, Nuclear Division
K. N. Harris, Senior Vice President, Nuclear Operations
W. H. Bohlke, Vice President,Nuclear Engineering & Licensing
J. E. Geiger, Vice President, Nuclear Assurance
J. B. Hosmer, Director, Nuclear Engineering
R. E. Grazio, Director, Nuclear Licensing
H. N. Paduano, Manager, Technical Programs
J. G. West, Manager, Nuclear Security
J. J. Zudans, Manager, NSS
A. L. Smith, Electrical/Instrumentation and Control Chief
T. C. Grozan, Principle Engineer, Nuclear Licensing
W. A. Skelley, Senior Staff Engineer
J. C. Gallagher, Senior Investigator, NSS
J. J. Hutchinson, Supervisor, Component Specialist

NRC Representatives at Exit

K. D. Landis, Section Chief, Region II
L. S. Mellen, Operational Programs, RII
M. Thomas, Reactor Inspector, RII
M. D. Hunt, Reactor Inspector, RII
P. J. Fillion, Reactor Inspector, RII

2. Licensee Employees at Exit on November 18, 1991

J. L. Broadhead, President, FPL Group
J. H. Goldberg, President, Nuclear Division
K. N. Harris, Senior Vice President, Nuclear Operations
W. H. Bohlke, Vice President,Nuclear Engineering & Licensing
J. E. Geiger, Vice President, Nuclear Assurance
J. B. Hosmer, Director, Nuclear Engineering
R. E. Grazio, Director, Nuclear Licensing
H. N. Paduano, Manager, Technical Programs
R. C. Gross, Manager, Outside Services/Nuclear Engineering
J. Scarola, Manager, Equipment Support and Inspection
R. L. Wade, Manager, Analysis and Controls
J. J. Zudans, Manager, NSS
D. L. Smith, Chief, Electrical/Instrumentation and Control
G. Salamon, Licensing Supervisor, Turkey Point
T. C. Grozan, Principle Engineer, Nuclear Licensing
W. A. Skelley, Senior Staff Engineer
J. C. Gallagher, Senior Investigator, NSS

NRC Representatives at Exit

S. D. Ebneter, Regional Administrator, Region II
K. D. Landis, Section Chief, Region II
K. M. Clark, Public Affairs Officer, Region II