August 28, 2002

EA 02-162

Mr. Fred Dacimo
Vice President - Operations
Entergy Nuclear Operations, Inc.
Indian Point Nuclear Generating Units 1 & 2
295 Broadway, Suite 1
Post Office Box 249
Buchanan, NY 10511-0249

SUBJECT: INDIAN POINT UNIT 2 - NRC SUPPLEMENTAL/PROBLEM IDENTIFICATION AND RESOLUTION INSPECTION REPORT NO. 50-247/02-010

Dear Mr. Dacimo:

The NRC conducted a supplemental and problem identification and resolution inspection from June 17 through July 19, 2002, at the Indian Point Unit 2 facility. The team, which consisted of seven senior inspectors and a fire protection engineer, focused on Entergy's actions to address the underlying performance issues that led to the facility's placement in the "multiple/repetitive degraded cornerstone" column of the Action Matrix. The team reviewed plant performance in the areas of design control, human and equipment performance, problem identification and resolution, and the implementation of the Fundamentals Improvement Plan. The enclosed report documents the inspection results, which were discussed with you and other members of your staff during an exit meeting on August 8, 2002.

The team determined that Entergy made progress in addressing the underlying performance issues which led to the multiple degraded cornerstone designation. The Fundamentals Improvement Plan identified the scope and extent of the performance issues, incorporated action plans to address these issues, and established appropriate indicators to measure your progress in completing these actions. The team concluded that the progress in these areas was primarily due to significant senior management oversight and strong emphasis on site personnel and management accountability. However, continued senior management attention is warranted to further strengthen performance, particularly as it relates to some inconsistencies in the quality of engineering evaluations and corrective actions. Further, the completion of the Fundamentals Improvement Plan, including the design basis initiatives, is important to assure continued improvement.

This inspection completes the supplemental activities for the Red finding associated with the February 2000 steam generator tube failure and for the performance issues associated with the August 1999 reactor trip. The NRC plans to conduct a Regulatory Performance Meeting with you on September 4, 2002, to discuss the areas of focus and your plans for continued improvement.

Based on the results of this inspection, one preliminary finding of low to moderate safety significance (White) was identified involving the central control room west wall fire barrier, which the team assessed as moderately degraded prior to February 2002. Entergy's identification of the initial degradation, which was not easily detectable, was commendable. The initial corrective actions taken improved the fire resistance of the wall; however, these actions did not assure that the wall conformed to the licensed three-hour fire barrier design assumptions and the extent of condition review was not thorough. Entergy established a compensatory fire watch in accordance with the fire protection program. However, this finding is an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600. The current Enforcement Policy is included on the NRC's website at http://www.nrc.gov.

We believe that we have sufficient information to make a final significance determination for the degraded fire wall issue (Preliminary White). However, before we make a final decision in the matter, you have the opportunity to request a regulatory conference to discuss your evaluation and any differences with the NRC's evaluation of this issue, or to send us your position in writing regarding your perspectives on the facts and assumptions applied by the NRC to determine this finding and its significance. If you choose to request a regulatory conference, you should be prepared to meet within 30 days of the receipt of this letter. In such a case, we encourage you to provide supporting documentation at least one week prior to the conference in order to facilitate effectiveness and efficiency. The regulatory conference will be open for public observation. If you decide to submit only a written response, please send your submital to the NRC within 30 days of the receipt of this letter.

Please contact Mr. David Lew at (610) 337-5120 within 10 business days of the receipt of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision, and you will be advised by separate correspondence of the results. Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

During the inspection, the team also identified three findings of very low safety significance (Green). These three findings were determined to be violations of NRC requirements. However, because of their very low safety significance and because the issues have been addressed and entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny these non-cited violations, you should provide a response with the basis for your denial, within 30 days of the receipt of this letter, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-001; with copies to the Regional Administrator, Region 1; the Director, Office of Enforcement; and the NRC Resident Inspector at the Indian Point 2 facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if you choose to provide one) will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public

Electronic Reading Room). To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction.

Sincerely,

/RA/

Brian E. Holian, Deputy Director
Division of Reactor Projects

Docket No. 50-247
License No. DPR-26

Enclosure: Inspection Report 50-247/02-010

Attachment 1 - Supplemental Information

cc w/encl: J. Yelverton, Chief Executive Officer
M. Kansler, Senior Vice President and CEO
J. Herron, Senior Vice President
R. J. Barrett, Vice President - Operations
C. Schwarz, General Manager - Operations
D. Pace, Vice President - Engineering
J. Knubel, Vice President Operations Support
J. McCann, Manager, Nuclear Safety and Licensing
J. Kelly, Director of Licensing
C. Faison, Manager - Licensing, Entergy Nuclear Operations, Inc.
H. Salmon, Jr., Director of Oversight, Entergy Nuclear Operations, Inc.
J. Fulton, Assistant General Counsel, Entergy Nuclear Operations, Inc.
W. Flynn, President, New York State Energy, Research
and Development Authority
J. Spath, Program Director, New York State Energy Research
and Development Authority
P. Eddy, Electric Division, New York State Department of Public Service
C. Donaldson, Esquire, Assistant Attorney General, New York Department
of Law
T. Walsh, Secretary, NFSC, Entergy Nuclear Operations, Inc.
Mayor, Village of Buchanan
R. Albanese, Executive Chair, Four County Nuclear Safety Committee
S. Lousteau, Treasury Department, Entergy Services, Inc.
M. Slobodien, Director Emergency Programs
B. Brandenburg, Assistant General Counsel
P. Rubin, Operations Manager
Assemblywoman Sandra Galef, NYS Assembly
County Clerk, Westchester County Legislature
A. Spano, Westchester County Executive
R. Bondi, Putnam County Executive
C. Vanderhoef, Rockland County Executive
E. Diana, Orange County Executive
T. Judson, Central NY Citizens Awareness Network
M. Elie, Citizens Awareness Network
D. Lochbaum, Nuclear Safety Engineer, Union of Concerned Scientists
Public Citizen's Critical Mass Energy Project
M. Mariotte, Nuclear Information & Resources Service
F. Zalcman, Pace Law School, Energy Project
L. Puglisi, Supervisor, Town of Cortlandt
Congresswoman Sue W. Kelly
Congressman Ben Gilman
Congresswoman Nita Lowey
Senator Hilary Rodham Clinton
Senator Charles Schumer
J. Riccio, Greenpeace
A. Matthiessen, Executive Director, Riverkeepers, Inc.
cc w/encl (cont'd):
M. Kapolwitz, Chairman of County Environment & Health Committee

A. Reynolds, Environmental Advocates
M. Jacobs, Executive Director, Westchester Peoples Action Coalition
D. Katz, Executive Director, Citizens Awareness Network
P. Gunter, Nuclear Information & Resource Service
P. Leventhal, The Nuclear Control Institute
K. Copeland, Pace Environmental Litigation Clinic

<u>Distribution w/encl</u>: **(VIA E-MAIL)**
H. Miller, RA/J. Wiggins, DRA
F. Congel, OE (2) (RIDSOEMAILCENTER)
H. Nieh, RI EDO Coordinator
W. Kane, NRR
B. Sheron, NRR
D. Dambly, OGC
D. Holody, ORA
R. Urban, ORA
P. Habighorst, SRI - Indian Point 2
S. Richards, NRR (ridsnrrdlpmlpdi)
P. Eselgroth, DRP
P. Milano, PM, NRR
G. Vissing, PM, NRR (Backup)
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R. Martin, DRP
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No. 50-247

License No. DPR-26

Report No. 50-247/02-010

Licensee: Entergy Nuclear Operations, Inc.

Facility: Indian Point Nuclear Generating Unit 2

Location: Buchanan, New York 10511

Dates: June 17 - July 19, 2002

Team Leader: W. Schmidt, Senior Reactor Inspector, Division of Reactor Safety (DRS)

Inspectors: L. Scholl, Senior Reactor Inspector, DRS
L. Prividy, Senior Reactor Inspector, DRS
S. Barber, Senior Project Engineer, Division of Reactor Projects (DRP)
D. Orr, Senior Resident Inspector, Three Mile Island, DRP
M. Gray, Senior Reactor Inspector, DRS
D. Frumkin, Fire Protection Engineer, Office of Nuclear Reactor Regulation
R. Fuhrmeister, Senior Reactor Inspector, DRS

Approved by: Wayne L. Schmidt for David C. Lew
Performance Evaluation Branch
Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000247-02-10, on 6/17 - 7/19/2002, Entergy Nuclear Operations, Inc.; Indian Point Generating Unit 2; supplemental and problem identification and resolution inspection focused on design control, human and equipment performance, corrective actions, and the central control room west wall fire barrier.

The team conducting this inspection consisted of six regional inspectors, a senior resident inspector, and a fire protection engineer from the Office of Nuclear Reactor Regulation. The team identified one preliminary finding of low to moderate safety significance (White), which is also an apparent violation of NRC requirements. The NRC will make a final determination of significance in the future. The team also identified three findings of very low safety significance (Green), that were violations of NRC requirements and classified as non-cited violation. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using NRC Manual Chapter (MC) 0609, "Significance Determination Process (SDP)." Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process (ROP) website at http://www.nrc.gov/reactors/operating/oversight.html.

Background

In the 4th Quarter 2000, the NRC designated Indian Point 2 (IP2), then owned and operated by Consolidated Edison Company of New York, Inc. (ConEd), a multiple/repetitive degraded cornerstone facility within the ROP action matrix, in accordance with the guidance in NRC MC 0305 "Operating Reactor Assessment Program." This action followed identification of the Red inspection finding concerning performance issues that led to the February 2000 steam generator tube failure.

To monitor licensee progress at addressing these performance issues, the NRC in accordance with the action matrix, conducted a variety of activities including inspections (baseline, supplemental, and augmented), management site visits, quarterly assessments, meetings with licencee management, reviews of performance metrics, and independent verification of corrective actions.

The NRC completed a supplemental inspection in February 2001, in accordance with the guidance in NRC MC 0305 and NRC Inspection Procedure (IP) 95003. The 95003 inspection focused on performance problems identified as a result of the Red inspection finding and from the August 1999 complicated reactor trip. The inspection results indicated that the plant was operating safely, with an acceptable margin of safety, and that continued operation was acceptable. However, while there were some improvements, the team identified problems similar to those that contributed to the Red finding and the August 1999 complicated plant trip, particularly in the areas of design control, human and equipment performance, and problem identification and resolution. Based on the outcome of the 95003 inspection, the NRC concluded that continued heightened oversight of IP2 was necessary until the NRC gained confidence in the performance improvement program to substantially address the performance issues that underlie the degraded cornerstones.

In September 2001, Entergy Nuclear Operations, Inc., (Entergy) purchased IP2. Entergy completed detailed performance self-assessments and developed a Fundamentals Improvement Plan (FIP) that covered the areas needing improvement identified in the NRC 95003 inspection report.

Performance Assessment

Overall, the team found that Entergy operated IP2 safely and that through implementation of the FIP progress had been made in improving performance in the areas of design control, equipment and human performance, and corrective actions. Specifically, the team determined:

- Overall, the quality of engineering products has improved, and design and licensing basis controls have been strengthened. Performance monitoring allowed management to focus on important areas including open condition report (CR) evaluations, temporary modifications, and work orders (WOs) on engineering hold. Based on a review of selected system health reports, WOs on engineering hold, surveillance test results, and plant walk-downs, the team concluded the results of the design basis initiative (DBI) reviews to date have been appropriately comprehensive to identify and evaluate design and licensing basis problems. (Section 1.)

- Overall, equipment performance improved. Entergy reduced the backlogs in corrective maintenance WOs, operator workarounds, central control room (CCR) deficiencies, and corrective maintenance items on engineering hold. The elective maintenance backlog remained high, but the prioritization appeared appropriate. Initial predictive maintenance efforts have identified equipment that needed attention prior to failure. Monthly component and system health reports helped management to focus attention and resources. Implementation of the work control process showed some improvement. The maintenance rule program provided appropriate actions to address degrading system performance. (Section 2.)

- Entergy actions to address human performance issues included training, management observations, and error tracking represented improvements. The overall station human error rate and number of equipment mis-positioning events have declined, based on FIP indicators. Through interviews, the team concluded that plant personnel generally acknowledged, accepted, and were very supportive of Entergy's performance improvement initiatives. (Section 3.)

- Entergy improved the effectiveness of the corrective action program (CAP), including proper identification and documentation of issues at a low threshold, and generally well conducted evaluations and effective corrective actions. Through interviews, the team found that Entergy plant personnel at various levels in the organization understood and voiced strong support for the CAP, which was important given past issues concerning the program.

  While Entergy has made improvements, the team identified some inconsistences in CAP implementation, indicating the need for Entergy to continue to focus on the thoroughness of evaluations and corrective actions, particularly as they relate to engineering. Specifically, the team identified ineffective design and extent of condition reviews of the degraded CCR west wall fire barrier. The team also identified three green findings relative to incomplete issue evaluation or actions that were not fully effective. Additionally, several minor issues were noted concerning incomplete evaluations and instances where Entergy did not identify potential negative trends. (Section 4.)

On balance, the team concluded that Entergy acceptably addressed the areas of performance weaknesses associated with the August 1999 complicated reactor trip and the February 2000 steam generator tube failure. This inspection completes the supplemental activities for the Red finding associated with the February 2000 steam generator tube failure and for the performance issues associated with the August 1999 reactor trip.

Cornerstone: Mitigating systems

- **Preliminary White** - The team identified an apparent violation of License Condition 2.K of Facility Operating License DPR-26. License Condition 2.K requires that Entergy implement and maintain in effect all provisions of the NRC approved fire protection program, which states that a three-hour rated wall will be constructed to separate the control building from the turbine building. In 1978, to meet the three-hour rating, the wall was to have been built in accordance with the design specification Underwriters Laboratories (UL) U902. Contrary to the above, in February 2002, the wall was found not to be constructed in accordance with UL U902.

  The combined effect of the identified deficiencies was that, as of February 2002, passages existed through both the outer brick and inner portions of the wall. If a significant amount of smoke and gasses were to penetrate the wall, this could result in the CCR becoming uninhabitable, causing the operators to resort to using the Alternate Safe Shutdown System. These conditions did not represent a three-hour fire barrier. The NRC preliminarily risk assessment, using Phase 2 of the NRC Fire SDP described in MC 0609, Appendix F, considered the wall a moderately degraded fire barrier having low to moderate safety significance (White). Until repairs could be completed, Entergy established a compensatory fire watch in accordance with the IP2 fire protection program. This issue is being treated as an apparent violation, consistent with the NRC Enforcement Policy. **(AV 50-247/02-010-001)**

  Entergy actions in identifying original construction deficiencies in the CCR west inner wall in February 2002 were commendable. However, the corrective actions taken were not fully effective in restoring the wall to its three-hour rated design configuration. Additionally, the initial extent of condition was not sufficient to identify other degraded fire barrier walls. At the close of the inspection, Entergy continued to review the design and installation of fire walls particularly, in the areas that interfaced with the central control, cable spreading, and 480 volt switchgear room structures.

- **Green** - The team identified a non-cited violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action concerning three issues with the control and monitoring of lubrication oil used on the turbine driven auxiliary boiler feed water pump (22 ABFP). Each issue involved incomplete evaluations that led to repeat problems and potential for pump damage.

1. The evaluation and corrective actions following identification in February 2002 that the wrong oil was added to the turbine speed governor were not fully effective. The evaluation of this issue identified that operators were not logging the quantity or specification of oil added during rounds or operation of equipment, but no actions were taken to address the issue. Additionally, the team noted that on July 10, while preparing to run the pump, Entergy identified additional confusion regarding the specification of oil to be added to the governor, an issue that should have been resolved.

2. Station personnel did not identify that oil analysis results in May 2002 showing a decrease in oil viscosity indicated that the wrong oil was likely added to a pump bearing and that corrective actions for a similar problem previously identified in May 2001 were ineffective.

3. The evaluation and corrective actions following identification in October 2001 of issues with the required oil level in the pump inboard bearing were not fully effective, specifically the design drawing, the vendor manual, and operator training contained inconsistent information.

These issues were evaluated using Phase I of the NRC SDP to have very low safety significance (Green), because pump operability was not directly affected. These issues are being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy based on the very low safety significance, and because the issues have been entered into Entergy's CAP. **(NCV 50-247/02-010-002)**

- **Green -** The team identified a non-cited violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action concerning the failure to promptly identify, determine the cause, and correct circuit breaker amptector setpoint database errors. The control of design setpoints is necessary to ensure the availability, reliability and capability of safety-related electrical systems. This issue was evaluated using Phase I of the NRC SDP and determined to have very low safety significance (Green), because the team did not identify any instances where a circuit breaker would not have been able to perform its safety function. This issue is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy based on the very low safety significance, and because it has been entered into Entergy's CAP. **(NCV 50-247/02-010-003)**

- **Green** - The team identified a non-cited violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action concerning the failure to identify that vibration of the non-safety-related SI accumulator topping pump caused stresses in adjacent safety-related piping that were above the code allowable values. The team evaluated this issue using Phase I of the NRC SDP, determining it to have very low safety significance (Green), because liquid penetrant examinations in the areas of high stress did not identify any piping damage. This issue is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy based on the very low safety significance, and because it has been entered into Entergy's CAP. **(NCV 50-247/02-010-004)**

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Report Details

The NRC performed this inspection to review the actions taken by Entergy Nuclear Operations, Inc., (Entergy) to improve performance at Indian Point 2 (IP2) as stated in their Fundamentals Improvement Program (FIP). At the time of the inspection IP2 was in the "multiple/repetitive degraded cornerstone" column of the Reactor Oversight Process (ROP) action matrix described in NRC Manual Chapter (MC) 0305.

Background:

IP2 was designated as a "multiple/repetitive degraded cornerstone" plant in the 4th quarter of 2000. To monitor licensee progress in addressing these performance issues, the NRC in accordance with the action matrix, conducted a variety of activities including inspections (baseline, supplemental, and augmented), management site visits, quarterly assessments, meetings with licensee management, reviews of performance metrics, and independent verification of corrective actions.

The NRC performed a supplemental inspection in accordance with NRC Inspection Procedure (IP) 95003, in February 2001, in response to the "red" finding associated with the February 2000 steam generator tube failure event and performance issues identified as a result of a reactor trip with complications in August 1999. That inspection identified performance issues, broadly categorized into four areas:

- Engineering design/licensing basis and configuration control - Weakness in the ability to retrieve, verify, and assure the quality of engineering products, particularly design basis information.

- Equipment performance - A tendency, in some instances, for the plant staff to accept degraded conditions.

- Human performance - Some limitations in the application of resources , for example, staffing issues and training weaknesses.

- Implementation of the corrective action process - Inconsistent reinforcement of existing management standards with respect to staff performance, particularly in implementation of the corrective action program (CAP).

In September 2001, Entergy purchased IP2 from Consolidated Edison Company of New York, Inc., (ConEd). Entergy initiated a comprehensive internal self-assessment that reached conclusions similar to the NRC regarding underlying performance issues at IP2. Entergy developed the FIP to address and track comprehensive improvement. The FIP was submitted to the NRC on January 25, 2002.

1. **Engineering**

a. Inspection Scope

The team evaluated the status of Entergy initiatives to improve engineering performance and the results achieved. Specifically, the team reviewed Entergy's progress in completing the design basis initiatives (DBIs) described in the FIP. These initiatives were intended to improve the quality of engineering products and more specifically, improve the control and retrieval of the IP2 design and licensing basis. This was a broad area of weakness previously identified in the NRC 95003 inspection. The DBIs cover the following six areas:

- Optimization of the modification and drawing update process.
- Design basis issues resolution, including tracking the closure of condition reports (CRs) and work orders (WOs) on engineering hold that involve design issues.
- Program improvements in discrete areas such as fuse control, hydraulic modeling of fluid systems, equipment environmental qualification, and calculation maintenance.
- Calculation upgrade efforts to improve the control process and specific calculation groups.
- Design and licensing basis document improvements, including issuance of system design basis documents and safety analysis report verification activities.
- Electrical wiring validation reviews to confirm the configuration of the reactor protection system and control circuits for the emergency diesel and gas turbine generators.

The team reviewed the scope of the DBIs to confirm that they addressed the causes of previously identified problems. The team also compared the status of each DBI to project schedules and reviewed significant deviations to understand potential impacts on the pace of improvement efforts.

The team examined the quality of the DBI results and their resolution by reviewing a sample of CRs written for issues identified as part of the DBI effort. For these CRs, the team assessed Entergy's performance to determine that each problem was appropriately described and bounded, equipment operability and potential plant risk implications were addressed, likely causes were evaluated, and effective corrective actions were identified and completed in a timely fashion.

Finally, the team independently assessed the comprehensiveness of the DBIs by reviewing a sample of CRs, calculation changes, temporary modifications (TMs), and WOs on engineering hold that were generated separate from the scope of the DBIs and which had design control implications. The team reviewed these documents to verify whether these issues should have reasonably been identified as part of the completed DBI efforts.

b. Findings

Overall, the team concluded that Entergy made significant improvements using the FIP to address the previous weaknesses in the quality of engineering products and design and licensing basis control. FIP performance monitoring allowed management to focus on important areas including open CR evaluations, TMs, and WOs on engineering hold. Based on a review of selected system health reports, surveillance test results, and plant walk-downs, the team concluded the results of the DBI reviews to date have been appropriately comprehensive to identify and evaluate design and licensing basis problems. Despite the overall improvement, engineering involvement in the CCR west wall fire barrier issues, and in a number of the corrective action findings and other minor issues, indicated the continued need for supervision and management to provide significant oversight of activities to ensure the completeness of evaluations and the adequacy and effectiveness of corrective actions.

Entergy maintained an internal web-based site to track progress in completing the FIP. The web-site identified the major milestones for each DBI and their status. It also indicated the current and projected work-off rate for various engineering backlog issues against internal goals. Additionally, the web-site identified those DBI schedules which require additional management attention to ensure time-critical milestones are completed. Cautionary notes described the potential impacts and management's intentions going forward.

In general, Entergy was meeting their schedules for completing the DBIs. Of 31 DBI milestone schedules tracked on the website, 25 remained on schedule and six had cautionary notes regarding potential schedule impacts. The team reviewed these notes and determined they typically involved schedule impacts due to program alignment and coordination issues or adjustments based on lessons-learned during earlier DBIs. For example, the team determined that Entergy was revising their schedule for completing design basis documents (DBD's). Originally, Entergy committed to complete and issue all DBDs in 2002. However, the last two DBDs (fire protection and electrical separation) were scheduled for completion in 2003. Entergy management indicated that completing these DBDs in 2003 would better align these efforts with the ongoing fire protection improvement project tracked in the engineering programs DBI. The team concluded the identified schedule impacts were reasonable, and the overall pace of DBI efforts remained within Entergy's schedule. However, since many of the DBIs involve multi-year efforts, the team also concluded that significant work remains to be completed within the identified schedules.

In reviewing the sample of CRs resulting from the DBI program the team determined that the problems generally involved discrepancies or incompleteness in design or licensing basis information. Based on the sample reviewed, the team concluded Entergy personnel described problems in sufficient detail to determine the scope of the issues and adequately evaluated equipment operability and potential plant risk implications. Corrective actions to confirm the design basis and remove inconsistencies were being tracked within the CAP. Additionally, Entergy management tracked the schedule of corrective actions both within the CAP and the DBI backlog work-off charts. The team determined the schedule for corrective action was timely and commensurate with the problems identified.

The team concluded that the DBI efforts have been appropriately comprehensive to identify and evaluate design and licensing basis problems. This conclusion was based on the reviewed sample of: CRs and WOs on engineering hold (not identified through DBI efforts), system health reports, surveillance test results, and on observations during plant walk-downs.

2. <u>Equipment Performance and Work Management</u>

a. <u>Inspection Scope</u>

Entergy monitored the corrective actions taken to improve 12 areas involving equipment performance and work management. The areas included: improving work management and work preparation, instrument and controls (I&C) maintenance effectiveness, and the preventive maintenance (PM) program. Entergy also began developing a predictive maintenance program. In order to assess the effectiveness of the FIP process, the team reviewed specific aspects in several of these areas. The review considered current performance compared to that of about one year ago. The specific areas reviewed included the following:

- Appropriateness of the elements in the FIP to track progress.

- Work control, in particular, on-line maintenance. Additionally, some outage work being planned for the Fall 2002 refueling outage (RFO15) was reviewed. Changes implemented since April 2002 to improve work control included:

    - Supporting the implementation of the Maximo project, which is a new computer-based software system that manages the identification, planning, scheduling, performance and archiving of maintenance work activities.

    - Issuing a new procedure, ENN-WM-100, “Work Request (WR) Generation, Screening, and Classification”, that implements standard guidelines for WR prioritization and screening for on-line work at all Entergy plants.

- Corrective, preventive, and elective maintenance backlogs.

- System health and equipment performance as discussed in selected system health reports.

- Maintenance Rule (MR) (a)(1) systems and action plans to return them to MR (a)(2) status.

The team conducted interviews, reviewed self-assessments and CRs, and conducted plant walkdowns to assess these specific areas. Most of the CRs selected involved the service water (SW), auxiliary feedwater (AFW), emergency diesel generator (EDG), residual heat removal (RHR), safety injection (SI), and 480 VAC systems. The CRs were reviewed to determine if the problem was effectively evaluated and proper corrective actions were being implemented to preclude repetition.

b. Findings

Overall, the team found that Entergy improved equipment performance. No significant problems were noted regarding the progress being reported in the FIP for the 12 areas associated with equipment performance and work management. Backlogs of corrective maintenance WOs, operator workarounds and CCR deficiencies, and corrective maintenance items on engineering hold have been steadily decreasing in 2002. The elective maintenance backlog remained high, but the prioritization appeared appropriate. Initial predictive maintenance efforts have identified equipment that needed attention prior to failure. Monthly component and system health reports helped management to focus attention and resources. The PM optimization initiative was on target with about 50% of the approximate 50,000 equipment items completed. Implementation of the work control process showed some improvement. The Maintenance Rule program provided appropriate actions to address degrading system performance.

Backlogs for corrective maintenance items, CCR alarms and deficiencies, operator workarounds, and corrective maintenance items on engineering hold have been steadily decreasing in 2002. For example, the corrective maintenance backlog in January 2002 was more than 500; in June 2002 there were 315 items. There were no operator workaround items. No risk significant issues were identified in a review of elective maintenance work orders in the SW, AFW, EDG, RHR, SI, and 480 VAC systems. Review of open elective maintenance items for these systems indicated proper prioritization. An increasing elective maintenance backlog appeared to be due, in part, to Entergy screening the corrective maintenance WOs for inclusion in the elective category.

Initial predictive maintenance efforts were successful regarding vibration testing and analysis of the SI and AFW pumps. Stiffening of the 21 SI pump motor pedestal and replacement of the 23 AFW pump motor during RFO15 were some examples of the corrective actions planned to improve equipment reliability. However, some predictive maintenance efforts have been deferred during the 1st half of 2002 due to a reallocation of resources to address I&C PM problems identified by the equipment reliability group's self-assessment as noted below.

At the end of 2001, the equipment reliability group performed a self-assessment intended to improve equipment performance monitoring, corrective action, PM implementation, and equipment reliability. CRs were issued to track the resolution and implementation of the self-assessment recommendations. The assessment identified significant problems in the I&C area in that many of the I&C PM packages were not being tracked as a part of the PM program, and at that time, many of the PM tasks were overdue. Also, I&C procedures lacked guidance to assure adequate completion and consistent performance. These problems were addressed in the 1st half of 2002 such that the backlog of I&C overdue PMs was eliminated and PM procedures were being improved. Mechanical and electrical PMs have been performed satisfactorily.

Monthly component health reports were being presented and discussed with management to focus attention and resources appropriately. The team reviewed the health reports for SW, AFW, EDG, RHR, SI, and 480 VAC systems. In general, the health reports appropriately reflected the recent performance of the system and the CRs that identified recently encountered problems.

Implementation of the work control process showed some improvement. Based on interviews, the team concluded that plant personnel were beginning to gain confidence in the new work management system, although there were some recognized problems in implementing Maximo. Planning and scheduling were improving, but still needed further improvements. For example, many of the corrective actions implemented in the second half of 2001 in response to CR 200106950 involved training of plant personnel to be diligent and sensitive to maintenance on equipment out of service and its impact on the equipment unavailability time tracked for MR purposes. This CR involved maintenance on the 21 EDG fuel oil transfer pump in the summer of 2001 that placed the EDG system into MR (a)(1) status due to increased unavailability time caused by poor planning and scheduling. While the effectiveness review for CR 200106950 was not scheduled for completion until August 2002, the team did not observe any similar problems. Also, good results concerning the implementation of work activities during the Fall 2001 mid-cycle outage were largely attributed to the extra effort devoted to improve planning and scheduling. Regarding outage work control, the team noted that readiness reviews were being conducted for major projects to be implemented during RFO15.

The team observed ongoing efforts to trend repeat maintenance items and improve equipment maintenance. An Entergy working group reviewed all WOs monthly to identify repeat maintenance problems. CRs were appropriately issued to address problem areas. In the equipment reliability group's self-assessment report of January 2002, repeat maintenance was recognized as an area requiring corrective action to resolve identified problems and improve performance. Notwithstanding, the team observed that repeat maintenance was an area in need of continued focus, especially concerning valves. Examples included repeat problems with the main feedwater regulating valves, the AFW pump discharge flow control valves, some containment isolation valves, SW essential/non-essential header manual isolation valve, and a low pressure steam dump valve. Entergy has corrective actions in place to improve the reliability of these valves.

MR action plans addressed systems with degraded performance. The number of MR (a)(1) systems decreased from 17 in the 3rd quarter 2001 to six in the second quarter 2002. Improvements were attributed largely to better monitoring and corrective actions for rotating equipment. For example, in October 2001 six safety-related pumps were in the alert status during pump inservice testing. As of July 2002, the 22 RHR pump was the only safety-related pump in the alert status. Entergy plans to replace this pump and motor in RFO15.

One observation from the effectiveness review conducted in response to the February 2000 steam generator tube leak and the complicated reactor trip of August 1999 was the lack of aggressive oversight of the MR expert panel. This observation was largely attributed to the infrequent meetings of the expert panel in 1999 and 2000 and hence, the panel's lack of involvement with MR issues. This problem was being tracked by CR 200110137. The team reviewed the evaluation and corrective actions associated with this CR by discussing the issue with several MR expert panel members. The panel has been meeting quarterly throughout 2001 and 2002 with an established agenda provided prior to each meeting. Some of the agenda items included action plans for restoring (a)(1) systems to (a)(2) status and changes to MR basis documents. The team concluded that the expert panel was currently exercising appropriate oversight of MR activities.

Human Performance

a. Inspection Scope

The team focused on Entergy's actions to improve human performance, reviewed FIP and departmental human error metrics, and conducted open door interviews with Entergy personnel to assess the attitude of plant workers.

The team reviewed Entergy's Human Performance (HU) Program including error prevention training, coaching and the use of coaching cards, department and station tracking of the time between the occurrence of human errors, and the evaluation of human error CRs. Entergy described their program in procedures: ENN-PL-162, Revision 0, Entergy Human Performance Policy; ENN-HU-101, Revision 0, Human Performance Procedure, and Station Administrative Order (SAO)-141, Revision 0, Station Coaching Program.

The team observed portions of the 16 hours of human error prevention classroom training given to each Entergy employee and long term contractor. The team also observed the mock-up training which exposed students to many common everyday human error traps in industrial safety, radiological protection, and maintenance.

Regarding coaching and the use of coaching cards, the team interviewed the HU coordinator and in-plant coaches on the use of coaching cards, reviewed the requirements of SAO-141, and reviewed a sample of completed coaching cards.

The team reviewed the Entergy process for tracking the time between the occurrence of human errors at the individual department and station level. When an error occurs it is referred to as a human error clock reset. The team reviewed the three most recent department clock resets from each of the 25 departments to understand the types of issues that have been occurring.

The team conducted routine interviews during discussions of inspection topics and open door interviews. The open door interviews consisted of six different time periods during which any interested employee or contractor was invited to talk to team members regarding any issues they wished to discuss. A total of 14 people from many different plant departments (operations, engineering, maintenance, and nuclear quality assurance) participated in the open door interviews.

b. Findings

Overall, the team concluded that actions taken to address human performance issues, which included training, management observations, and error tracking, represented improvements. The overall station human error rate and number of equipment mis-positioning events have declined, based on FIP indicators. Through interviews, the team concluded that plant personnel generally acknowledged, accepted, and were very supportive of Entergy's performance improvement initiatives.

Regarding human error training, the team noted that students were very receptive and their comments were very favorable. In critiques of the training students noted that the identification of tools to offset human error traps as a positive initiative. The students also indicated that the training in the mock-up facility was relevant to their jobs and provided realistic human error trap situations.

Regarding coaching and the use of coaching cards, the in-plant coaches indicated that the program provided better focus than the previous management observation program because it mandated prompt, on-the-spot feedback to the coached employee. Although initially reluctant, the employees became more responsive and receptive to coaching. The team interviewed the HU coordinator and in-plant coaches on the use of coaching cards, reviewed the requirements of SAO-141, and reviewed a sample of approximately 435 completed coaching cards from April through June 2002. In May and June 2002, each of the 149 supervisors and managers exceeded the eight hours a month coaching goal by a significant margin.

Regarding department and station human error clock resets, the team noted that the times between resets ranged from about 5 to 28 days at the end of June 2002. Most departments listed reset times in the 5 to 18 day range with only a few above 20 days. The HU program encourages frequent departmental resets to lower the threshold and to increase the sensitivity to human performance issues. The team also interviewed individual department HU program coordinators and noted a low threshold for initiating HU clock resets.

Based on the feedback from interviews the team concluded that plant personnel generally acknowledged, accepted, and were very supportive of Entergy's performance improvement initiatives.

4. Problem Identification and Resolution

a. Inspection Scope

The team reviewed operations department logs including out-of-specification readings, instrument and calibration surveillance records completed within a recent thirty day period, temporary field changes, CCR deficiencies, and operator burden and workaround lists. The team reviewed these documents to identify various processes that existed at IP2 for identification of problems that should then be entered into the CAP for evaluation and resolution. The broad spectrum of items was selected to assess Entergy's threshold for problem identification.

The team observed and interviewed licensed operators in the CCR, a non-licensed operator performing primary auxiliary building rounds, conducted independent walkdowns in plant areas containing risk significant equipment, and interviewed several plant personnel in various organizations to assess whether Entergy was identifying problems at a low threshold and entering them into the CAP.

The team reviewed Entergy's "self-identification" performance indicator to assess management efforts for encouraging early problem identification. The team also reviewed about 200 significance level (SL) 3 CRs initiated from June 13 to June 23, 2002, to determine if problems were being properly characterized and prioritized in the CAP. SL3 CRs were used to assess Entergy's threshold for conditions adverse to quality (an SL3 is generated to document the least significant condition adverse to quality in Entergy's CAP).

The team reviewed the CRs listed in Attachment 1 to determine whether Entergy adequately prioritized and evaluated problems entered into the CAP. Entergy's CAP assigns CRs a significance level, with SL1 representing problems at the greatest risk, and SL4 a condition that is not adverse to quality, yet improvement through a change process may be desired. The most recent SL1 was initiated on January 10, 2002, to address a non-nuclear industrial safety issue. SL2 CRs were much more frequent, with 110 initiated in the 1st quarter of 2002. The team focused on CRs associated with risk significant systems, including SW, AFW, EDG, RHR, SI, 480 VAC, and 120Vdc. Associated CRs at all significance levels (open or closed status) were reviewed to assess Entergy's prioritization and evaluation.

The depth of CR evaluation expected is based on potential significance. SL1 CRs require a full root cause evaluation; SL2 CRs required an apparent cause evaluation; and, although SL3 CRs do not necessarily require an evaluation, corrective actions need to be implemented. SL4 CRs may be addressed and closed at management discretion. CRs listed in Attachment 1 were reviewed to determine if Entergy was following the evaluation requirements required by the IP2 administrative order, SAO-112, "Condition Reporting Process." The team also assessed the evaluations for accuracy, appropriateness of corrective actions implemented, consideration for extent of condition, reportability reviews, and operability determinations.

The team observed corrective action screening committee (CASC) and corrective action review board (CARB) meetings. The CASC reviewed all recently initiated CRs and WOs, verifying proper prioritization and ensuring initiation of immediate corrective actions if not yet taken. The CARB established initial SL1, and as appropriate, SL2 investigation charters and reviewed the effectiveness of all SL1 CRs, most SL2 CRs, and the CAP overall.

The inspection team reviewed the corrective actions associated with CRs, WRs, and other documents listed in Attachment 1 to determine whether the corrective actions addressed the identified causes and were scheduled or completed in a timely fashion. This review focused on risk significant systems, including SW, AFW, EDG, RHR, SI, 480 VAC and 120Vdc. Work requests and SL4 CRs were scrutinized for conditions adverse to quality which would necessitate an SL of greater significance.

The team also reviewed Entergy's self-assessment of the CAP as described in the IP2 Quarterly Assessment Report for the 1st Quarter 2002 and the 4th Quarter 2001. Other Entergy self-assessment documents were reviewed as listed in Attachment 1. Entergy maintained a number of performance indicators to gauge the health and effectiveness of the CAP. The performance indicators reviewed are listed in Attachment 1. The team also reviewed Entergy's methods for tracking and trending CR causal factors and repeat human performance and equipment issues. The team observed several SL2 CR presentations to the CARB.

The team reviewed aspects of the Employee Concerns Program (ECP) including: how concerns were received, investigated, and dispositioned; and, how individuals were kept informed on the status of their concerns. The ECP manager was interviewed to evaluate program priorities and to discuss a Nuclear Safety Culture Survey Entergy conducted in the 1st quarter of 2002. Entergy described this program in procedures: ENN-PL-125, Revision 0, Employee Concerns Policy and ENN-QV-105, Revision 1, Guidelines for the implementation of the Employee Concerns Program.

a. <u>Findings</u>

Entergy improved the effectiveness of the CAP, including proper identification and documentation of issues at a low threshold, and generally well conducted evaluations and effective corrective actions. The Entergy personnel interviewed, at various level of the organization, voiced strong support for the CAP. However, the team identified three green findings relative to incomplete issue evaluation or actions that were not fully effective. Additionally, several minor issues were noted concerning incomplete evaluations and instances where Entergy did not identify potential negative trends. While Entergy has made improvements, the team identified some inconsistences in CAP implementation, indicating the need for Entergy to continue the focus on the thoroughness of evaluations and corrective actions, particularly as they relate to engineering.

Entergy identified problems at a low threshold and entered them into the CAP. The team did not identify any issues through log or record review, plant walkdown, or during personnel interviews that had not already been correctly entered into the CAP for evaluation and resolution. Entergy management used the performance indicators to monitor and evaluate the threshold for problem identification. The team did not identify any conditions adverse to quality that had not been entered into the CAP.

In most cases, Entergy's evaluation of problems was sufficiently detailed to identify the likely root or apparent causes and provide for appropriate corrective action. The CASC effectively assigned the appropriate significance level for priority, review and evaluation. The CARB challenged CR owners and elicited more effective corrective actions when warranted.

Entergy appropriately monitored CAP performance with corrective action group and FIP metrics. Based on the corrective action and maintenance backlogs within the risk significant systems selected, the team did not identify items that represented an adverse effect on plant risk. The team also observed that repeat problems are critically reviewed by Entergy management.

The ECP manager was implementing a new program replacing the Ombudsman program that had been implemented by ConEd. The program was virtually identical to the program being implemented at IP3 and standardizes the approach used at both units. The new program had been endorsed by senior station and corporate management. The ECP appeared to be effective. The team noted that the Entergy Nuclear Safety Culture Survey indicated a healthy nuclear safety culture and the presence of a safety conscious work environment.

- <u>Auxiliary Feedwater Pump Oil Control Issues</u>

Green - The team identified a non-cited violation of 10 CFR 50 Appendix B, Criteria XVI (Corrective Action), for failure, in three instances, to promptly identify and correct conditions regarding the control and monitoring of lubrication oil used on the turbine driven auxiliary boiler feedwater pump (22 ABFP). While none of these issues directly effected operability, each involved incomplete evaluations that led to repeat problems and potential for pump damage.

1. In February 2002, Entergy identified that the wrong oil was added to the turbine speed governor. The engineering evaluation concluded that the oil used in the pump bearing had been added to the governor, but that the difference in viscosity was not significant. The CR recommended changing the specification of the governor oil to the same oil as used in the bearing to prevent further confusion.

   The evaluation of this issue was not fully effective in that it identified that operators were not logging the quantity or specification of oil added during rounds or operation of equipment, but no actions were taken to address the issue. Additionally, the team noted that on July 10, while preparing to run the pump, Entergy identified additional confusion between the PM work order and the operations department lubrication database, regarding the specification of oil to be added to the governor (an issue that should have been previously resolved). Entergy initiated CRs 200206818 and 200206914 to address these issues.

2. Station personnel did not identify that oil analysis results in May 2002 (which shows a decrease in oil viscosity) indicated that the wrong oil was likely added to a pump bearing and that corrective actions for a similar problem previously identified in May 2001 were ineffective. In review of the AFW system CR history, the team identified:

    1. In May 2002 the viscosity had decreased out-of-specification from the last quarter with minimal pump runtime. CR 200204701 concluded that the pump remained operable, and was closed to a work order to change the oil. The cause of the out-of-specification condition was not evaluated. The inspector questioned the reason for the decrease in oil viscosity. In response, Entergy determined the probable cause was the addition of an incorrect grade oil during the past three months, most likely on operator rounds or during oil sampling.

    2. In May 2001 the viscosity had decreased greater than 10% from the previous quarter with minimal pump runtime. Entergy determined the 22 AFW pump remained operable and changed the bearing oil to restore the viscosity level to within specifications. Entergy personnel concluded this condition was likely caused by personnel adding the incorrect grade oil during routine activities. Corrective action was taken to discuss the problem with tool room personnel who issue oil to plant personnel.

    The team concluded that the 22 ABFP remained operable with the low oil viscosity condition based on a review of bearing temperatures during recent pump testing, which were normal, and bearing oil analysis results, which showed that the oil additives remained in specification. Entergy initiated CR 200206818 to identify and evaluate this repetitive problem.

3. In October 2001, actions were not fully effective to properly evaluate and correct issues concerning the oil level required for the inboard pump bearing, specifically in the design drawing, vendor manual, and operator training information. Based on a plant tour the team questioned the bearing oil level, which appeared to be low compared to a level mark at mid-span of the sight-glass. Entergy personnel indicated the current oil level was correct at about a 1/4" above the bottom of the sight-glass. Entergy personnel further indicated a scribe mark in the brass housing of the sight-glass provided this level indication for operators. The team verified that, in addition to the mid-level marking, a 1/4" high scribe mark had been made in the sight-glass brass housing. The team reviewed operator training and control of bearing oil levels, and determined that an internal computer web site provided operator training on specific bearing oil level requirements. For this bearing, the web site indicated the oil level was to be

maintained at mid-level. This training information contradicted the current 1/4" level being maintained by operators.

The team also found that this oil level issue was identified in CR 200110289 following the October 2001 shutdown, because when operators added oil to maintain level at the sight-glass mid-point, oil leaked out of the outboard seal and the level settled at the 1/4" level. The Entergy root cause analysis described operator confusion regarding the proper oil level in this bearing. The evaluation indicated the proper oil level was at the 1/4" level. However, it did not remove the mid-span marking, and did not determine the basis for the 1/4" mark, thus missing an opportunity to identify a less than fully documented design basis. Furthermore, the evaluation did not identify that operator training reinforced maintaining oil at the incorrect level.

The team also concluded that Entergy did not maintain design documents to describe the installed pump bearing lubrication system. The pump vendor manual had not been revised to indicate the use of sight-glasses, and the design documentation for modifying the pump lubrication system could not be retrieved. Also, in 1999, Entergy exchanged correspondence with vendors and performed additional analysis to revise the sight-glass levels different than that shown on the applicable design drawing. This information was not incorporated into the vendor manual and the drawing was not revised. Furthermore, the team determined the oil level scribe mark had not been applied via written documentation to help ensure the mark was applied consistent with design documentation. Entergy initiated CR 200206901 to correct the operator training material, CR 200206891 to address the failure to update the vendor manual to reflect the replacement of oilers with sight-glasses, and CR 200206913 to address the informality of design documentation with regard to determining the proper oil level and the failure to revise the vendor drawing to reflect this information.

These issues were performance deficiencies because the Entergy oil control program specifies the type of oil to be used, consistent with manufacturers recommendations, to provide for reliable operation of equipment and because NRC regulations require that design basis requirements be correctly translated into drawings, procedures and instructions. The issues affect the mitigating system cornerstone since the AFW system is used to remove decay heat from the reactor during postulated accident conditions. The issue is more than minor since it affects the mitigating system attribute of maintaining the reliability of the AFW system to respond during postulated accident conditions. However, this issue was evaluated using Phase I of the NRC SDP described in IMC 0609, Appendix A, and determined to have very low safety significance (green), since the out-of-specification oil condition did not result in the 22 ABFP being inoperable. Consequently, there was no loss of safety function, and technical specification requirements were met.

These issues are considered a non-cited violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action. However, because of the very low safety significance of each issue, and because Entergy personnel initiated CRs to addresses these conditions, this finding is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 50-247/02-010-002)**

- Use of Incorrect Revision of 480 volt Breaker Calibration and Test Procedures

Green - The team identified a non-cited violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action, concerning the failure to promptly identify, determine the cause, and correct circuit breaker over current device (Amptectors) setpoint (SPIN) database errors. The control of design setpoints is necessary to ensure the availability, reliability and capability of safety-related electrical systems. The team did not identify any instances where a circuit breaker would not have been able to perform its safety function.
The team questioned the adequacy of the evaluation of CR 200204947 which identified incorrect amptector calibration and a test procedure issue. During the evaluation, Entergy determined that several amptector SPIN database entries were in error. Although Entergy appropriately evaluated the effects on the specific circuit breaker discussed in this CR, there was no determination of the cause of the database error. The team noted that Entergy reviewed SPIN database entries for circuit breakers with similar setpoints, identifying additional errors, including the EDG output breakers. Entergy reviewed test data for the affected circuit breakers to ensure they remained functional. However, the team noted that at the time of the inspection, the EDG breakers data had not yet been corrected. The team also noted that while corrective actions were being tracked to correct the known errors and verify other settings, the actions were not due until September 2, 2002, and no interim measures were in place to prevent the use of inappropriate SPIN information. Finally, the team noted that although calculation FFX-00141-00, “IP2 Amptector Setting Verification, Sensor and Tolerances,” Rev. 0, had been issued for use in November 2000 with revised amptector settings, there was no documented evaluation to justify delaying the implementation of the revised setpoints over an extended period of time.

Based on the team’s concern, Entergy reviewed the remainder of SPIN entries involving Amptectors and corrected the EDG breaker entry. That review identified additional errors involving other circuit breakers and additional corrective actions were assigned to correct the errors. The team reviewed these identified errors and did not identify any issues that would have affected circuit breaker functionality. Entergy determined the cause to be transposition errors between the calculation and the setpoint device data form (SPDDF), or between the SPDDF and the SPIN entry. However, the CR did not identify actions to determine why this apparent database quality control issue occurred or why it would be limited to Amptector settings in the database.

This is a performance deficiency in that the Entergy evaluation did not adequately identify the scope of the problem or address the causes in appropriate detail relative to incorrect SPIN entries. The issue affects the mitigating system cornerstone since the overcurrent trip settings of safety-related equipment were potentially affected. This issue is considered to be greater than minor since control of design setpoints is necessary to ensure the availability, reliability and capability of mitigating systems. This issue was evaluated using Phase I of the NRC SDP described in MC 0609, Appendix A and determined to have very low safety significance (Green), because the team did not identify any instances where a circuit breaker would not have been able to perform its safety function.

The failure to identify the cause of the SPIN database errors and to correct the errors in a timely manner is considered a non-cited violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action. However, because of the very low safety significance of this issue, and because it has been entered into the Entergy's CAP in CR 200207608, the issue is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 50-247/02-010-003)**

- SI Topping Pump Vibration

Green - The team identified a non-cited violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action, concerning the failure to identify that vibration of the non-safety-related SI accumulator topping pump caused stresses in adjacent safety-related piping that were above the code allowable values. This positive displacement pump provides pure water makeup from the refueling water storage tank to the SI accumulators to maintain the required level. While the SI accumulator topping pump and its associated pulsation dampeners and piping are non-safety-related, adjacent suction and discharge piping is safety-related.

The team inspected the SI accumulator topping pump area with the system and cognizant design engineers, who indicated that the suction piping continues to vibrate as reported in CR 200202155 when the topping pump was operated. Based on additional questions, the team determined that Entergy had not fully evaluated the cause and potential effects of the vibration, specifically:

1. The piping stresses associated with the vibration and possibility of piping fatigue had not be analyzed.
2. The cause concerning the gaps between the bottom of the pipe and the supports had not been established.
3. The evaluation did not consider root or contributing causes of the vibration due to: possible malfunction of the suction and discharge pulsation dampeners, or possible misalignment of the pump during corrective maintenance in February 2002, prior to the initial identification of the vibration problem.

Entergy issued CR 200206823 to address these concerns. The CR was classified as a rework activity and assigned with a SL2 priority. Calculations indicated that, based on the observed vibration levels, the stresses in the adjacent safety-related piping exceeded the code allowable value. Based on engineering's recommendation, operations removed the pump from service pending determination of the cause of the vibration and corrective action to resolve it. To ensure that the adjacent safety-related suction piping had not been damaged, due to fatigue, Entergy performed liquid penetrant examinations in three high stress locations, and found no indications of cracking.

This is a performance deficiency in that the Entergy evaluation did not adequately identify the scope of the problem or address the causes in appropriate detail relative to possible fatigue of safety-related piping adjacent to the SI topping pump. The issue affects the mitigating system cornerstone since the safety-related piping exceeded the code allowable stress values. This issue is considered to be greater than minor since Entergy needed to conduct liquid penetrant examinations to ensure that no piping damage had occurred. This issue was evaluated using Phase I of the NRC SDP described in MC 0609, Appendix A and determined to have very low safety significance (Green), because liquid penetrant examinations in the high stress areas did not identify any damage.

The failure to identify the consequences of the SI topping pump vibration on adjacent safety-related piping is considered a non-cited violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action. However, because of the very low safety significance of this issue, and because it has been entered into the Entergy's CAP in CR 200206823, the issue is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 50-247/02-010-004)**

Other Issues

The team identified one unresolved item. The team also identified several other instances concerning incomplete evaluations and instances where Entergy did not identify potential negative trends. Although these issues were considered minor (MC 0612, "Power Reactor Inspection Reports" Appendix B, Section C, "Minor Questions"), they indicated the need for Entergy to continue the focus on the thoroughness of evaluations and corrective actions, particularly as they relate to engineering. These issues constitute violations of minor significance that were not subject to enforcement action in accordance with Section VI of the NRC's Enforcement Policy.

- Reactor Coolant System Temperature Sensor Equipment Qualification

The team identified a lack of clarity related to the need for the narrow range resistance temperature detectors (NR-RTDs) to be environmentally qualified (EQ). Entergy personnel initiated CR 200200276 dated January 8, 2002, to identify and evaluate increased setpoint drift assumptions for the high steam line flow setpoint based on recent test results. The high steam flow setpoint operates in coincidence with either a low average reactor coolant system temperature (low T-ave) or low steam line pressure setpoint to initiate automatic main steam line isolation during a postulated main steam line break (MSLB) accident. The CR evaluation indicated the coincident low T-ave setpoint should not be credited since the NR-RTD circuits were not EQ.

The team found that the coincident low T-ave setpoint was credited in the IP2 UFSAR, Section 14.2.5, along with high steam line flow to provide the initial main steam line isolation signal. The setpoint response time was also identified in the UFSAR. The team concluded that Entergy personnel did not evaluate why the NR-RTDs were excluded from the EQ program, even though the UFSAR credited their operation in a MSLB environment. Additionally, the team identified that Entergy personnel missed a prior opportunity to identify the discrepancy between the UFSAR description, the NR-

RTD function, and their non-EQ status during development of the design basis document (DBD) for the reactor coolant system (RCS).

As a result of the team's concern, Entergy personnel initiated SL2 CR 200206777 to evaluate the NR-RTD EQ issues in greater detail, including a re-evaluation of the plant response to a postulated MSLB accident in containment crediting only the coincident low steam pressure setpoint, instead of the low T-ave setpoint. Entergy concluded the time to reach the main steam line isolation signal would increase by about a second. However, since the current analysis includes an additional two second margin to main steam isolation, Entergy concluded the analysis provides adequate margin to accommodate this increase without changing the results of the analysis. The team concluded this re-analysis provided an operability basis commensurate in detail with the UFSAR accident analysis description. At the close of the inspection, Entergy continued to review this issue. The team considered it unresolved pending review of Entergy's evaluation. **(URI 50-247/02-010-005)**.

- <u>22 Auxiliary Boiler Feedwater Pump Gland Drains</u>

The team questioned the timeliness of corrective action to improve the 22 ABFP outboard packing gland well drain leak-off following an April 27, 1999, issue where the level in the gland well increased to the point that the pump shaft was submerged (allowing water to enter the pump outboard bearing). CR 199903384 was initiated and corrective actions were focused on improving the design of the packing gland well drain. System engineers proposed an additional overflow drain hole below the bearing housing elevation. The engineers also proposed that the drain tubing be disconnected from each well and a funnel arrangement used to route the packing leak off. A funnel arrangement would allow overflow to the floor if a drain backup occurred. Overflow to the floor below the bearing housing would eliminate oil contamination by water submergence. The corrective actions were closed in November 1999, to an administrative engineering request to develop a modification.

Subsequently, in September 2001 a system engineer identified clogged packing gland well drains on the 21 motor driven AFW pump (21 ABFP). The drain arrangement on this pump included adequate overflow holes below the bearing housing; therefore, the bearing housings were not submerged. A SL3 CR 200109037 was initiated and the clogged inboard and outboard gland well drain tubing was cleared on September 26, 2001. The team determined that the occurrence of clogged packing gland well drains in the AFW pump room still existed as evidenced by the 21 ABFP problem. Entergy's intention to improve the 22 ABFP packing gland well drain during RFO15 did not appear timely.

- <u>21 Auxiliary Boiler Feed Pump Overheated Packing</u>

The team concluded that Entergy's SL1 CR 200110289, while evaluating multiple AFW system problems during an October 2001 plant shutdown, did not address the contributing cause of a poor post-maintenance test conducted earlier that month for the 21 ABFP packing overheating. Corrective actions were implemented to improve the packing replacement maintenance procedures with detailed post-maintenance testing instructions. However the corrective actions did not address non-conservative decisions made by senior reactor operators and the CASC on October 8, 2001 to leave the 21 ABFP in a standby condition without having adequately demonstrated that the packing gland required no further adjustment. That decision assumed that a future maintenance activity, to run-in the packing once the pump started for any reason, would be successful. This conclusion was contrary to the overheating situation that actually occurred on October 27, 2001. The issue of the ABFP packing overheating was a Green finding in Inspection Report 50-247/01-010.

- Leading Edge Flow Meter Software Control

The team reviewed CR 200100909 which was initiated to document lack of control of software and data stored electronically for operation of the leading edge flow meter (LEFM) and other equipment. Although the LEFM is not a safety system, it is important because it provides an input to the heat balance program used to determine plant power and ensure operation within the IP2 licensed power rating. The team identified several aspects of the issue which were not adequately addressed by Entergy when evaluating the subject condition report. For example, the evaluation concluded that an extent of condition review was not necessary even though the CR identified issues with four other software systems. In addition to the LEFM, the meteorological data display, ISO-phase bus monitoring and house service boiler controllers were affected. Furthermore, the corrective actions were not adequate in that at the time of the inspection there were three floppy discs in the LEFM console. One appeared to be the proper vendor supplied disc while the other two appeared to be uncontrolled copies. The uncontrolled discs were removed and CR 200206778 was initiated to document this issue.

The team also noted that there was limited oversight of vendor work on LEFM. Work orders for the system contained very limited description of work performed and did not state specifically what tests and checks were performed to ensure the system was operable when returned to service. The team found that the vendor generated trip reports that discussed work performed in detail. However, Entergy had difficulty locating the reports (eventually locating several onsite and obtaining copies of others directly from the vendor). CR 200206912 was initiated to evaluate the adequacy with which equipment was appropriately tested and documented prior to returning equipment to service following work by vendors. Finally, the team noted that a work order documented the identification of a mis-wiring issue but no CR was written at the time. CR 200206473 was initiated during the inspection to address the issue.

The team considered the failure to initiate a CR for the mis-wiring and the failure to identify multiple copies of floppy discs in the LEFM console to be weaknesses in the area of problem identification. The failure to perform an extent of condition review was also considered to be a weakness in the evaluation of issues. The team did not identify any conditions what would have affected the LEFM accuracy.

- Type II Fire Barrier Degradation

The team reviewed CR 200201933 initiated on February 20, 2002, which documented a ½" by 20" gap in the control room floor which is the boundary between the control room and the cable spreading room. The gap is required to be sealed to provide a Type II barrier to mitigate smoke propagation in the event of a fire in the space below. This was initially a SL2 CR which would require an extent of condition review. Based on additional inspection of the floor the condition was determined to not be generic and the CR was downgraded to an SL-3 report. The team subsequently noted that on February 24, 2002 there were three additional CRs initiated to document other issues with Type II barriers associated with the control room envelope. The conditions, identified during the performance of PI-V-17-1, Penetration Fire Barrier Seal Inspections, were as follows:

1. CR 200202092 - Fire barrier penetration #15/11-034 has 4 conduits and 1 sealtite. The sealtite was not sealed where it passed through the control room floor.
2. CR 200202095 - Fire barrier penetration #15/11-083 was found to be breached by an approximate 1" hole (CCR north wall).
3. CR 200202098 - Fire barrier penetration # 15/11-085 was found to be breached by an approximate 1" hole (CCR north wall).

The team considered this to be a weakness in that an apparent adverse trend was not identified and appropriately evaluated. Entergy initiated SL4 CR 200207143 to address the issues.

- Procedure Usage Adverse Trend

The team reviewed SL2 CR 200204950 which was written to evaluate the use of an incorrect revision of post-maintenance test procedure for 480 volt circuit breakers. The CR documented that a search of the IP2 CR database for key words “wrong procedure”, “incorrect procedure” and “old procedure” identified “many” related CRs. Eight specific examples were listed, all of which occurred in 2001 and 2002. Entergy did not evaluate this or specify any corrective actions to address this apparent adverse trend. During the inspection Entergy performed an additional search of the CR database which identified six additional instances of “wrong revision” issues in 2001 and 2002. SL2 CR 200206916 was initiated to address this issue.

5. Fire Protection - Central Control Room West Wall

a. Inspection Scope

The team reviewed the actions taken by Entergy following their identification of original construction deficiencies in the CCR west fire barrier wall; as discussed in Section 1RO5.2 of NRC inspection report (IR) 50-247/2002-002. The team reviewed CR 200202031 generated following the initial identification, the WO generated to improve the condition of the inner wall, pictures taken of the as-found and as-left inner wall, and the original design basis for this fire barrier. Team members also observed the condition of the wall as Entergy prepared for reconstruction. As part of the review the team assessed the effectiveness of Entergy's initial and final corrective actions. The team, with the assistance of the Region I Senior Reactor Analyst, assessed the risk of a turbine building fire relative to the as-found condition of the CCR west wall.

b. Findings

(Preliminary White) The team identified an apparent violation of License Condition 2.K of Facility Operating License DPR-26. License Condition 2.K requires that Entergy implement and maintain in effect all provisions of the NRC approved fire protection program, which states that a three-hour rated wall will be constructed to separate the control building from the turbine building. In 1978, to meet the three-hour rating the wall was to have been built in accordance with the design specification Underwriters Laboratories (UL) U902. Contrary to the above, in February 2002, the wall was found not to be constructed in accordance with UL U902.

The fire protection program states that a three-hour rated wall will be constructed to separate the control building from the turbine building. The wall was not constructed in accordance with the design specification UL U902 for a three-hour rated barrier. The UL U902 specification consisted of a composite wall including a four inch (nominal) brick outside wall tied to a four inch (nominal) concrete block inner wall. The concrete block wall requires internal reinforcement to ensure its structural integrity when used as a load-bearing wall.

Background

Entergy identified deficiencies in the concrete block inner wall in February 2002 as part of an initiative to improve the leak tightness of the CCR. After discovery, Entergy declared the wall inoperable and established a compensatory fire watch, as required by the IP2 fire protection program.

Entergy took action to repair the inner wall, issuing WO IP2-02-25936 to "Repair the west masonry block wall in the CCR to meet construction standards for three-hour fire safety wall." The work step list for the WO requires removal of loose and deteriorated mortar, and repointing the joints by tightly packing mortar into the joints and tooling the joints to match the original profile. Entergy fire protection and civil engineering found these actions acceptable on March 4, 2002. At this point the compensatory fire watch was secured, because Entergy believed that the wall had been returned to a fully qualified three-hour barrier.

Entergy also completed an extent of condition evaluation which included identifying all other masonry walls reviewed in response to 1980 NRC Bulletin on Seismicity of Masonry Walls to determine which, if any, are also credited as fire barriers, and to perform walkdowns to assess the as-built condition of the walls. This action was closed on April 26, 2002, concluding that; "The population of block, brick, and brick/block walls identified under the IE Bulletin 80-11 masonry wall evaluation program that are also credited as fire barriers has been inspected..... All barriers were found structurally intact and sound, with no missing masonry blocks or bricks, and all joints mortared in a manner reflecting at least adequate craftsmanship....”

Discussion:

Team members conducted an in-office review of CR 200202031 as part of reviewing the May 16, 2002, Entergy SDP analysis and reviewed NRC and Entergy pictures of the as-found condition prior to February 2002 of the inner wall. This Entergy analysis assumed that the outer wall was properly constructed. Team members questioned whether the wall construction complied with the U902 design.

After several discussions between NRC staff and Entergy personnel, Entergy performed a more detailed review of the wall design and construction, finding additional deficiencies in the outer brick wall. This review resulted in the issuance of an additional CR 200205807, on June 10, 2002. Also on June 10, 2002, CR 200205818 was issued to document that a previous engineering assessment had not adequately addressed the extent of condition, and that the basis for acceptability of the apparent deviation between the as-repaired wall and the as-designed wall was not adequately documented. After this additional discovery, Entergy declared the wall inoperable again and established a compensatory fire watch, as required by the IP2 fire protection program.

During the week of June 17, 2002, team members conducted onsite inspections to determine details of pre-February 2002 construction of the entire west wall, while it was being destructively examined by Entergy. The team noted a number of deviations from the intended UL U902 design including: embedded steel structural members in the inner portion of the wall; and in the outer brick portion, a corbeled (recessed) section, an exposed steel lintel supporting bricks, and openings and unfilled gaps.

Analysis:

Pre- February 2002

The team identified a performance deficiency that the wall was not initially constructed in accordance with UL U902 in 1978. This was due, in part, to the U902 design not including embedded steel, corbeled brickwork, nor bricks supported by an exposed steel lintel. These conditions did not represent a three-hour fire barrier. The combined effect of the identified deficiencies was that, as of February 2002, passages existed through both the outer brick and inner portions of the wall. If a significant amount of smoke and gasses were to penetrate the wall, this could result in the CCR becoming uninhabitable, causing the operators to resort to using the Alternate Safe Shutdown System (ASSS).

Post - March 2002

The team determined that Entergy’s corrective actions, as of March 4, 2002, improved the construction of the inner wall, but did not ensure that the entire CCR west wall was restored to its design configuration, nor to a fully qualified three-hour fire barrier. The evaluation did not identify that the inner and outer walls and thus the entire barrier did not conform to the UL U902 design. Additionally, the extent of condition review did not identify deficiencies in other masonry fire walls, which Entergy subsequently discovered in June and July 2002, after team members questioned the design of the CCR west wall fire barrier.

The team reviewed actions taken by Entergy to determine why the extent of condition review, completed upon initial discovery of the inner wall construction deficiencies, did not identify additional deficiencies in the outer CCR west wall and in other masonry walls that are rated fire barriers. The team also reviewed actions taken in response to CR 200205807 which documented that the CCR west wall construction was not consistent with the design drawings or original construction specification. CR 200205818 was initiated to document and evaluate these two conditions. The team reviewed the associated CRs, discussed the issues with plant staff and attended the CARB meeting where the results of Entergy reviews were presented to plant management. The team found the review thorough and the recommended corrective actions appropriate to address the root causes. At the close of the inspection, Entergy continued to review the design and installation of fire walls particularly in the areas that interfaced with the central control, cable spreading, and 480 volt switchgear room structures. The fire watch established in June 2002 for the CCR west wall remained in place as repair work continued.

Significance Determination:

Based on the results of this inspection the NRC completed the Phase 2 Fire SDP assessment of the risk of the degraded CCR west wall, in the pre-February 2002 condition; including the deficiencies noted above, using the methodology described in Appendix F to MC 0609. The finding passed the Phase 1 screening criteria, requiring the Phase 2 evaluation. The finding affected the mitigating systems cornerstone. The deficiencies in the wall degraded the “Protection Against External Events” objective of the mitigating systems. Specifically, the deficiencies resulted in a decrease in the effectiveness of the fire barrier which separates the redundant safe shutdown equipment trains in the turbine building and the CCR. This could have resulted in a single large fire (such as a turbine generator failure with consequent large oil fire) damaging the ASSS power cables to the 22 ABFP and also causing the operators to have to abandon the CCR and utilize the ASSS for achieving and maintaining safe shutdown conditions.. A brief summary of the factors used in the SDP analysis follows:

Initiating Event Frequency - NRC used the frequency for turbine generator oil fires from the EPRI FIVE screening methodology (1.3E-2/yr)

Fire Barrier Term - NRC used the SDP failure probability for a moderately degraded fire barrier. This is based on the fact that, while the Entergy evaluation showed the wall may function as an effective thermal energy shield, the unsealed gaps and missing blocks in the wall could allow for the passage of smoke and gasses thereby rendering the CCR uninhabitable (-1.25).

Manual Suppression Term - At the time of the inspection, there were no documented fire brigade issues. Therefore, the NRC used the nominal operating condition failure probability of - 1 for manual suppression of the fire.

Automatic Suppression Term - The IP 2 design does not include area wide suppression systems in the turbine building. No credit for automatic suppression was given.

Remaining Mitigating Capability - The postulated fire could damage the cables for the 22 ABFP. The procedures for shutdown outside the control room provide instructions for local manual operation of the turbine driven 22 ABFP. The mitigating system credit for a steam driven train (-1) was given.

Final Risk Determination - From IMC 0609, Appendix F, Table 5.6, the final risk estimation, using an event likelihood of 1E-4 to 1E-5 for greater than 30 days (row E) with a remaining mitigating capability of -1, is WHITE.

Phase 2 Validation Analyses - The NRC conducted a detailed risk analysis to confirm the phase 2 SDP results. Entergy provided additional information which was considered in this analysis. The NRC concluded that the phase 2 risk analysis properly characterize the risk of degraded fire barrier.

Enforcement:

License Condition 2.K requires that Entergy implement and maintain in effect all provisions of the NRC approved fire protection program, which states that a three-hour rated wall will be constructed to separate the control building from the turbine building. In 1978, to meet the three-hour rating the wall was to have been built in accordance with the design specification UL U902. Contrary to the above, in February 2002, the wall was found not to be constructed in accordance with UL U902. This issue is being treated as an apparent violation, consistent NRC Enforcement Policy. Until repairs could be completed Entergy established a compensatory fire watch in accordance with the IP2 fire protection program. Based on this review the previous unresolved item 50-247/02-002-001 was considered closed. **(AV 50-247/02-010-001)**

6. Meetings, Including Exit

On June 19, July 12, and July 19 team members presented preliminary findings to Mr. Fred Dacimo and other members of the licensee staff. The licensee acknowledged the preliminary inspection findings. On August 8, 2002, the team presented an overall summary of the inspection results to Mr. Fred Dacimo and other members of the licensee staff. The licensee acknowledged the inspection findings. No material examined during the inspection should be considered proprietary.

ATTACHMENT 1

a. Key Points of Contact

R. Allen	Manager, Regulatory Affair
W. Axelson	Manager, Corrective Actions
W. Blair	Response Team Leader
F. Dacimo	Vice President, Operations
W. James	Maintenance and Construction Manager
J. McCann	Manager, Nuclear Safety and Licensing
D. Morris	Response Team Manager
P. Rubin	Director of Operations
G. Schwartz	Director of Engineering
C. Schwarz	General Manager - Operation
M. Vasely	System Engineering Section Manager
J. Ventosa	System Engineering Manager

b. List of Items Opened, Closed, and Discussed

Open

AV 50-247/02-010-001	NRC identified an apparent violation of the approved fire protection program, which states that a three-hour rated wall will be constructed to separate the control building from the turbine building.
URI 50-247/02-010-005	RCS Narrow Range RTD EQ

Open and Closed

NCV 50-247/02-010-002	Turbine Driven Aux Feed Pump Oil Issues
NCV 50-247/02-010-003	Setpoint Database not corrected for Circuit Breaker Overcurrent Protection Device Setpoints
NCV 50-247/02-010-004	SI Topping Pump Vibration Consequences to Safety-Related Piping

Closed

URI 50-247/02-002-001	Control Room West Wall Fire Barrier
VIO 50-247/00-010-03	Steam Generator Tube Failure

c. List of Documents Reviewed

Condition Reports

199808495
199810764
199903321
199903384
200001557
200001726
200004181
200004543
200006602
200007108
200007876
200009751
200010072
200010792
200100511
200101125
200101245
200101388
200101766
200102056
200102158
200102487
200102825
200102919
200103901
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200112623
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200201666
200201708
200201822
200202031
200202140
200202155
200202165
200202481
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200202589
200203035
200203132
200203177
200203246
200203770
200203801
200203925
200204039
200204238
200204538
200204679
200204701
200204721
200204750
200204751
200204831
200204928
200204934
200205091
200205093
200205108
200205167
200205410
200205807
200205818
200205919
200206329
200206417
200206568
200206777
200206818
200206823
200206866
200206887
200206889
200206891
200206901
200206913

Calculations

FEX-00141-00IP2 Amptector Setting Verification, Sensor and Tolerances, Rev. 0
MMM-00010-00, Revision 0, 9/12/91
FMX-00278-00, Revision 0, 9/14/01
PGI-00556, Evaluation of Fire Resistance Capability of Central Control Room, El 53' Masonry West Wall, Rev 0, 7/19/02

Procedures

ENN-IT-104	Software Quality Assurance Program, Rev. 1
PC-3Y5	DB-50 and DB-75 Breaker Amptector/Westector Calibration, Rev. 12
PT-3Y5	DB-50 and DB-75 Breaker Overcurrent Test, Rev. 10
SOP 15.1	Reactor Thermal Power Calculation, Rev. 38
CAG-20.107	Corrective Action Screening Committee Guidelines, Rev. 6
CAG-20.200	Corrective Action Review Board, Rev. 10
ENN-WM-100	Work Request Generation, Screening, and Classification
ENN-WM-101	On-Line Work Management Process
SAO-112	Condition Reporting Process

Self-Assessments

- Indian Point 2 Quarterly Assessment Report, 4th Quarter 2001
- Indian Point 2 Quarterly Assessment Report, 1st Quarter 2002
- Adverse Trend Detection and Condition Report Use, PI&R Preparation Document, May 24, 2002
- SL-3 Condition Report Closure Practices Review, June 21, 2002
- SL-2 Condition Report Effectiveness, SL-2 and SL-3 Condition Report Closure Practices, May 20, 2002
- Post-Entergy SL-2 Condition Report Effectiveness, PI&R Preparation Document, June 19, 2002
- Independent Quality Review of SL-2 and SL-3 Condition Report Responses, May 20, 2002

Corrective Action Program Performance Indicators

- Total Open Condition Reports (SL-1, 2 & 3)
- Number of Open Condition Report Evaluations
- Condition Report Evaluations Age
- Condition Report Implementing Corrective Action Age
- Quality of Apparent Cause Evaluations
- Quality of Root Cause Evaluations
- Repeat Events
- Condition Reports Initiated/Assigned by Department from 1/1/02 to 5/31/02
- CAG SL-2 Rejection from 1/01/02-5/31/02
- CAG SL-2 Rejection Rate
- Overall Corrective Action Program Index by Department
- CRS - Corrective Action Program Indicator - Self-Identification Ratio, 1/02-6/02

Work Orders

97-94436
01-19842
01-19526
02-25215
00-14977
00-17922
00-17951
00-16441
01-22870
01-22875
02-39070

Miscellaneous

I&C Preventive Maintenance Package No. 1509, Rev. 2, FW/Steam Generator Pressure to LEFM Console PT-3101, PT-3102, PT-3103, PT-3104
Vendor Manual #1158, "Instructions for Installation, Operation, Maintenance and List of Parts for Worthington Pumps" (22 AFW Pump)
Design Basis Document for the Reactor Coolant System/Steam Generator Blowdown System, Revision 0, December 30, 2000
Auxiliary Feedwater System Calculation Hierarchy (Roadmap), Drawing 328146-00, Revision 0
Temporary Field Change 2001059
Surveillance Test Procedure PT-R139, Residual Heat Removal Flow Setting and Check Valves, Revision 2, completed on 5/25/00
IP2 Oil Lubrication Task Sheets for Auxiliary Feedwater Pumps

d. List of Acronyms

ABFP	auxiliary boiler feed pump
AFW	auxiliary feed water
ASSS	alternate safe shutdown system
CAP	corrective action program
CARB	corrective action review board
CASC	corrective action screening committee
CCR	central control room
ConEd	Consolidated Edison Company of New York, Inc.,
CR	condition report
DBD	design basis document
DBI	design basis initiative
ECP	employee concerns program
EDG	emergency diesel generator
Entergy	Entergy Nuclear Operations, Inc.
EQ	environmental qualification
FIP	Fundamentals Improvement Plan
I&C	instrument and controls
IP2	Indian Point Unit 2
IR	inspection report
LEFM	leading edge flow meter

MC	Manual Chapter
MR	maintenance rule
MSLB	main steam line break
NR-RTD	narrow range - resistance temperature detector
PM	preventive maintenance
RHR	residual heat removal system
ROP	reactor oversight process
SAO	station administrative order
SDP	significance determination process
SI	safety injection system
SL	significance level
SPIN	setpoint database
SSFA	safety system functional assessment
TM	temporary modification
UFSAR	updated final safety analysis report
UL	Underwriter Laboratory
WO	work order
WR	work request