UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

December 19, 2003

Randall K. Edington, Vice
President-Nuclear and CNO
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

SUBJECT: COOPER NUCLEAR STATION - NRC PROBLEM IDENTIFICATION AND RESOLUTION INSPECTION AND THIRD QUARTER CONFIRMATORY ACTION LETTER INSPECTION REPORT 05000298/2003002

Dear Mr. Edington:

On November 4, 2003, the U. S. Nuclear Regulatory Commission (NRC) completed a team inspection at the Cooper Nuclear Station. The team completed the onsite portion of the inspection from September 15-26, 2003. The enclosed report documents the inspection findings, which were discussed on November 4, 2003, with Mr. S. Minahan and other members of your staff during a public exit meeting.

This inspection was an examination of activities conducted under your license as they relate to the identification and resolution of problems, and compliance with the Commission's rules and regulations and the conditions of your operating license. Also, the inspection examined activities related to the NRC Confirmatory Action Letter, dated January 30, 2003, and the Strategic Improvement Plan, Revision 2. Within these areas, the inspection involved examination of selected procedures and representative records, observations of activities, and interviews with personnel.

The team reviewed approximately 150 corrective action documents; 12 self-assessments; and numerous audits, procedures, industry information, and other documents. On the basis of the sample selected, the team concluded that there continued to be implementation problems with the evaluation of issues and the development of effective corrective actions. While problems were, in general, being identified by your staff and entered into the corrective action program, the evaluation and correction of these problems were not always fully effective particularly in the area of identification of degraded conditions requiring an operability determination. The team evaluated your corrective actions to address the substantive crosscutting issue in the area of problem identification and resolution and concluded that, while improvements have been made, there are continuing problems involving the evaluation and disposition of degraded conditions.

There were five Green findings identified during this inspection. These findings were determined to be violations of NRC requirements. However, because each finding was of very low safety significance and because they have been entered into your corrective action program, the NRC is treating these findings as noncited violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny these noncited violations, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region IV; the Director, Office of Enforcement, U. S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Cooper Nuclear Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be 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).

Sincerely,

/RA/

Arthur T. Howell III, Director
Division of Reactor Projects

Docket: 50-298
License: DPR-46

Enclosure:
NRC Inspection Report
05000298/2003002

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket.:	50-298
License:	DPR 46
Report No.:	05000298/2003002
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	September 15 through November 4, 2003
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Approved By:	Arthur T. Howell III, Director Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000298/2003002; 9/15/2003-11/4/2003; Cooper Nuclear Station; baseline inspection of the identification and resolution of problems and an inspection to verify provisions of the NRC Confirmatory Action Letter and the Cooper Nuclear Station Strategic Improvement Plan.

The inspection was conducted by five regional inspectors, one senior resident inspector, and one resident inspector. Five Green findings of very low safety significance were identified during this inspection and were classified as noncited violations. These findings were evaluated using the significance determination process.

Confirmatory Action Letter

The confirmatory action portion of this inspection was the third of a series of inspections performed by the NRC to assess Nebraska Public Power District's progress with respect to the implementation of their improvement plan and to verify the provisions outlined in the NRC Confirmatory Action Letter, dated January 30, 2003. The inspection primarily focused on the areas specified in the Confirmatory Action Letter which includes: (1) emergency preparedness; (2) human performance; (3) material condition and equipment reliability; (4) plant modifications and configuration control; (5) corrective action program, utilization of industry operating experience, and self-assessments; and (6) engineering programs. In addition, the inspection reviewed baseline inspection reports, licensee performance measures, and the licensee staff's utilization of performance indicators and assessed the progress in the above areas.

In the area of emergency preparedness, the licensee performance indicators, NRC performance indicators, and baseline inspection results indicated a satisfactory level of performance. In the area of human performance, efforts to improve performance have been less effective. Nevertheless, some improvements have been noted. In the four remaining Confirmatory Action Letter areas, the team concluded, by reviewing licensee performance indicators, NRC performance indicators, licensee self-assessments and baseline inspection results, that actions implemented have not resulted in sustained improved performance. Specifically, in the area of material condition and equipment reliability, actions completed to date have provided the necessary processes for improvement as demonstrated by the numerous equipment improvements recently completed. However, many of the licensee's performance indicators did not meet their performance goals, and the licensee continued to experience equipment reliability problems resulting in forced shutdowns or power reductions. Also problems have continued in the areas of configuration control, operability determinations, and with the evaluation of issues identified and the effectiveness of corrective actions. Lastly, engineering program improvements are in place, but more time is needed to implement the programs and evaluate effectiveness.

Identification and Resolution of Problems

The team reviewed approximately 150 corrective action documents, 12 self-assessments, and numerous audits, procedures, industry information, and other documents and determined that, while issues were adequately identified, problems persisted with the evaluation of issues and effectiveness of corrective actions. In several instances, information was available that indicated plant components were actually or potentially degraded; however, plant personnel failed to identify the degraded conditions. As a result, they did not evaluate the conditions, which allowed equipment to remain in service without performing operability determinations.

Since the 2000 identification and resolution of problems inspection, the NRC has identified that licensee personnel have failed on numerous occasions to recognize degraded conditions and perform the required operability determination. To date, corrective actions taken to address concerns with operability determinations have not been effective. All personnel interviewed stated they had no concerns with raising safety issues to management.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The team identified a noncited violation of Technical Specification 5.4.1a. Since February 2003, there were 17 examples where the licensee staff failed to follow preventive maintenance procedural requirements when replacing safety-related Agastat relays. The preventive maintenance program required safety-related Agastat relays to be replaced within 10 years from the date of manufacture. The team found that the requirement to adjust the start date for the next scheduled replacement activity in the preventive maintenance program was not followed.

  This finding is greater than minor because if left uncorrected it would become a more significant safety concern. This finding is of very low safety significance since the deficiency was confirmed to have not resulted in a loss of safety function (Section 4OA2b).

Cornerstone: Mitigating Systems/Barrier Integrity

- Green. The team identified a noncited violation of Technical Specification 5.4.1a. because the licensee staff failed to assess operability of instrument air accumulator check valves and the Feedwater Check Valve RF-CV-15CV as required by Procedure 0.5.OPS, "Operability Review of Notifications/Operability Determination," Revision 18.

  This finding is more than minor because the components were degraded and operability of those components was impacted. The finding was determined to be of very low safety significance since it did not result in the actual loss of a safety function or of one train of a safety function for greater than the Technical Specification allowed outage time. Also the finding was not risk-significant from a fire, seismic, flooding, or severe weather initiating event standpoint (instrument air accumlater check valves) nor did it represent a degradation of the barrier function of the control room or an actual open pathway of reactor containment or a reduction of the atmospheric pressure control function of reactor containment (Feedwater Check Valve RF-CV-15CV) (Section 4OA2b).

Cornerstone: Mitigating Systems

- Green. The team identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI. The licensee staff failed to identify and correct a condition where a safety-related Agastat relay in the residual heat removal system was replaced with a relay that was determined to be beyond its accepted service life. Because of a lack of effective controls of replacement relays, a relay was issued and installed that was the same age as the original relay. The purpose of replacing the original relay was that it was beyond its accepted service life.

This finding is greater than minor because if left uncorrected it would become a more significant safety concern. This finding is of very low safety significance because it did not result in an actual loss of a safety function or the actual loss of one train of the residual heat removal system for greater than its Technical Specification allowed outage time. Also, the finding was not risk-significant from a fire, seismic, flooding, or severe weather initiating event standpoint (Section 4OA2c).

Cornerstone: Miscellaneous

- Green. The team identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI. The licensee staff failed to correct a previously identified problem with conducting operability determinations. The NRC identification and resolution of problems inspections (NRC Inspection Reports 05000298/2000010 and 2001010), conducted August 2000 and September 2001, both identified multiple examples of failure to perform operability determinations as required by Procedure 0.5.OPS, "Operability Review of Notifications/Operability Determination." Previous Inspection Reports 05000298/2001008 and 2002004 each had one example of a noncited violation associated with the failure to perform an operability determination. These noncited violations combined with the two additional examples of failure to perform operability determinations, for the instrument air accumulator check valves and Feedwater Check Valve RF-CV-15CV, reflect inadequate corrective actions taken to address the repeated failure of site personnel to recognize degraded or nonconforming conditions.

  This issue is more than minor because it involved a credible impact on safety in that the failure to recognize when degraded structures, systems, or components require an operability determination or evaluation could have resulted in continued operation of the facility with systems, structures, and components not capable of performing their intended safety function. This finding is of very low risk significance because the unevaluated degraded conditions of the affected systems did not affect operability (Section 4OA2c).

Cornerstone: Mitigating Systems

- Green. A self-revealing noncited violation was identified for inadequate design control of the service water Zurn strainer control panels, in accordance with 10 CFR Part 50, Appendix B, Criterion III. This failure resulted in the placement of nonessential components and loss of configuration control for a relay and motor starter in the strainer control panels.

  This finding is more than minor because the licensee staff failed to implement appropriate design control measures for the service water Zurn strainer control panels, resulting in errors significant enough to require an operability determination and a design change to resolve the concerns. The finding is of very low safety significance because it did not result in an actual loss of a safety function or the actual loss of one train of the service water system for greater than its Technical Specification allowed outage time. Also, the finding was not risk-significant from a fire, seismic, flooding, or severe weather initiating event standpoint (Section 4OA5).

B. Licensee-Identified Violations

10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," states in part, that "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected." Contrary to the above, on four occasions, the licensee staff failed to identify and correct a condition in which safety-related Agastat relays were not replaced at the required frequencies prescribed in the preventive maintenance program and with replacement relays of appropriate age. This licensee staff-identified violation is of very low safety significance (Green) and is being dispositioned as a noncited violation. This violation is documented in their corrective action program as Resolve Condition Report 2003-0394.

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA2 Problem Identification and Resolution

a. Effectiveness of Problem Identification

(1) Inspection Scope

The team reviewed items selected across all cornerstones, with the exception of emergency preparedness, to determine if problems were being properly identified, characterized, and entered into the corrective action program for evaluation and resolution. Specifically, the review included a selection of approximately 150 corrective action program documents that included notifications, resolve condition reports, and significant condition reports. The team also reviewed numerous licensee audits and self-assessments, including audits of the corrective action program. The effectiveness of the audits and assessments was evaluated by comparing the audit and assessment results against self-revealing and NRC-identified findings.

The team interviewed station personnel, attended condition review group and corrective action review board meetings, and evaluated corrective action documentation to determine the licensee staff's threshold for identifying problems and entering them into the corrective action program. In addition, the team reviewed the licensee staff's evaluation of selected industry operating experience information to assess if issues applicable to the Cooper Nuclear Station were appropriately addressed.

The team also conducted walkdowns and interviewed plant personnel to identify other processes that may exist where problems and findings could be identified. The team reviewed work requests and interviewed engineering and maintenance personnel in order to understand the interface between the corrective action program and the work control process.

(2) Assessment

The team determined that problems were adequately identified and entered into the corrective action program with some exceptions noted below. During interviews, plant personnel indicated that they believed that a low threshold for entering problems into the corrective action program had been established. One noticeable difference from previous NRC inspections was the licensee staff's self-assessment of the Quality Assurance Organization. An independent Quality Assurance Program audit was conducted in July 2003 and found that the program was hampered by Quality Assurance not being proactive in identifying issues and improvement areas. In addition, the audit was critical of management's involvement in the Quality Assurance organization.

The team identified several instances where licensee personnel did not adequately identify problems and/or enter them into the corrective action program. The following examples describe the team's observations and findings.

Example 1

Strategic Improvement Plan (TIP) Action Plan 5.2.1.1, step 1b, required that all known operator work arounds be entered into the corrective action. This TIP action was completed and the licensee staff developed process changes to strengthen administrative tracking of them. The inspectors reviewed the current list of operator work arounds to determine if these issues were entered into the corrective action program. Eight operator work arounds had been identified by the licensee staff and were being tracked in a separate data base by the operations department; however, only six of the eight work arounds had been entered into the corrective action program with only the equipment deficiencies identified.

Operator actions necessary to compensate for equipment deficiencies were not entered or evaluated by the corrective action program. In one case, Resolve Condition Report 2001-0448, regarding an equipment deficiency with the control room fire alarm panel, was being tracked by Corrective Action Order 4175415; however, there was no specific discussion of this deficiency as an operator work around nor was there any corrective action program code to indicate it as such. The order was assigned to engineering, and engineering subsequently downgraded and removed the deficiency from the corrective action program without the knowledge of the operations department. No violation of NRC requirements was identified; however, the inspectors concluded that this was not in accordance with TIP Action Plan 5.2.1.1, step 1b.

Example 2

Introduction: The licensee staff failed to promptly identify and correct a condition associated with Agastat relays that were in service beyond the replacement frequency specified by the preventive maintenance program. The licensee staff identified four prior opportunities to identify and correct this condition since 1997. This condition was documented in Resolve Condition Report 2003-0394. The finding was determined to be of very low safety significance (Green). This is a licensee identified noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions."

Description: Resolve Condition Report 2003-0394 documented four opportunities to identify and correct a condition in which safety-related Agastat relays were not replaced in accordance with the established preventive maintenance procedure. As a result, these relays were allowed to remain in service beyond the approved qualified service life of 10 years from the date of manufacture. The four opportunities were described as follows:

1. In 1997, it was identified that there was an absence of a warehouse shelf life for Agastat relays. Corrective actions included the assignment of an arbitrary 15-year shelf life, based on a verbal discussion with the engineering environmental qualification coordinator. There was no documented analysis to support this value. This allowed Agastat relays to be installed, which had already exceeded their qualified life of 10 years.

2. In 1998, Agastat relays were being replaced with relays of the same manufactured age as those being removed. The engineering environmental qualification coordinator concluded that an appropriate approach was to base replacement on date of installation, rather than date of manufacture. This conclusion was not supported by an engineering evaluation. This was contrary to the vendor manual and preventive maintenance procedure.

3. During the 2001 Refueling Outage, five residual heat removal Agastat relays were identified as having exceeded their 10-year qualified life (Resolve Condition Report 2001-1115). The five relays were replaced. The licensee missed the opportunity to identify other Agastat relays with a similar condition and missed the opportunity to re-evaluate the established service life restriction of these relays. An unintended result was that the replacement relays for these five relays were in reality older than those which were removed.

4. Engineering Evaluation 02-010 re-evaluated the shelf life of Agastat relays and determined that this value could be extended to 20 years, but did not have an adequate basis to extend the shelf life an additional 10 years.

In each case, the licensee staff failed to perform adequate problem identification and take effective corrective action to ensure that the relays were replaced as scheduled with replacement relays that did not exceed an appropriate age. The team considered this to be the result of a lack of a questioning attitude, a willingness to waive procedural requirements based on verbal instructions, and a lack of depth of understanding of the integration of engineering evaluations, preventive maintenance program requirements, and spare parts storage and issuance.

The team reviewed the preventive maintenance program for Agastat relay replacement and determined that the program established a service life of 10 years based on the date of manufacturing. Therefore, this 10-year life included both shelf life and service life.

Analysis: The team determined that this finding was more than minor since if left uncorrected it would become a more significant safety concern. Specifically, since at least 1997, the licensee staff allowed safety-related Agastat relays to remain in service beyond the service life established in the preventive maintenance program. Failure of these components due to age could potentially cause the associated system to not function as designed to mitigate the effects of an accident. No actual failures of these normally de-energized relays was identified due to aging effects and there were no immediate safety concerns using the Significance Determination Process, under the Mitigation Systems Column; therefore, the finding screens as Green since the deficiency was confirmed to have not resulted in a loss of safety function.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions,” states in part that “Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.” Contrary to the above, on four occasions, the licensee staff failed to promptly identify and correct a condition in which safety-related Agastat relays were not replaced at the required frequencies prescribed in the preventive maintenance program with replacement relays of an appropriate age. This licensee staff-identified violation is of very low safety significance (Green) and is being dispositioned as a noncited violation. This violation is documented in their corrective action program as Resolve Condition Report 2003-0394.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The team reviewed approximately 150 corrective action program documents and supporting documentation, including apparent root cause and root cause evaluations, to ascertain whether the licensee staff identified and considered the extent of conditions, generic implications, common causes, and previous occurrences. In addition, the inspectors reviewed licensee staff evaluations of selected industry operating experience information, including operating event reports and NRC and vendor generic notices, to assess if issues applicable to the Cooper Nuclear Station were appropriately addressed.

The team also attended various meetings to assess the threshold of prioritization and evaluation of issues identified. The team attended a management performance review meeting, a plan-of-the-day meeting, a condition review group meeting, and a corrective action review board meeting.

(2) Assessment

The team identified a number of problems with prioritization and evaluation of issues. The team identified that 1 of 24 resolve condition reports, reviewed by the team, missed all or part of the apparent root cause of the event described in the condition report. In addition, the team identified two examples where licensee personnel failed to identify degraded conditions and did not perform an operability determination as required by procedure.

The team noted a significant improvement in the ownership and knowledge of the corrective action program by the condition review group and corrective action review board. Both the group and board were prepared to discuss the specifics of the corrective action documents on that day's agenda. The members were knowledgeable of the issues and asked probing questions.

Example 1

Introduction. Since February 2003, there were 17 examples where the licensee staff failed to follow procedural requirements as stated in work order documents for the replacement of safety-related Agastat relays. The finding was determined to be of very low safety significance (Green) and a noncited violation of Technical Specification 5.4.1a.

Description. Resolve Condition Report 2003-0428, initiated February 26, 2003, documented a condition in which Work Order 4175530 was performed during Refueling

Outage RE20 to replace Agastat Relay RHR-REL-K70B; however, the preventive maintenance start date was not revised in accordance with the work order instructions. The preventive maintenance included instructions to “update the PM start date per the manufacture date,” and this instruction was carried over to the work order instructions. The purpose of this action was to adjust the next scheduled relay replacement date to ensure that the qualified service life of 10 years from the date of manufacture was not exceeded. In the case of Relay RHR-REL-K70B, the preventive maintenance start date was not revised in accordance with the work order instructions.

The team requested copies of the work orders for all safety-related Agastat relays that had been replaced since February 1, 2003, to determine if this condition was corrected. A total of 17 Agastat relays were replaced under the preventive maintenance program during this period. None of the preventive maintenance start dates were revised as required.

In addition, the team determined that the apparent cause for Resolve Condition Report 2003-0428 was inadequate. The apparent cause was stated as “inadequate guidance in the preventive maintenance documents to provide meaningful instructions to performers to accomplish the adjustment of preventive maintenance dates to comply with the vendor’s recommendation.” The team reviewed the guidance in the preventive maintenance documents and determined that it clearly stated that relays were to be replaced within 10 years from date of manufacture.

In addition, the corrective action specified in this resolve condition report stated that revision of the preventive maintenance documents would not be necessary because of a planned action to establish a longer service life. The team considered this corrective action to be inadequate because it did not address the stated apparent cause and credited an engineering evaluation that was not yet completed, reviewed, approved, or issued.

Analysis. The team determined that this finding was more than minor since if left uncorrected it would become a more significant safety concern. Specifically, the licensee staff failed to follow procedural requirements to adjust the preventive maintenance start date to ensure that safety-related Agastat relays would be replaced within the qualified service life. This failure resulted in an increased possibility of age-related failures of these components. The team determined that past and current operability of the systems in which these relays were installed was not impacted by this issue because no age-related Agastat relay failures were noted. Using the Significance Determination Process Phase 1 worksheet, as described in Inspection Manual 0609, Appendix A, the finding did not result in an actual loss of safety function or one train of a safety system for greater than its Technical Specification allowed outage time or screen as potentially risk significant due to a fire, seismic, flooding, or severe weather initiating event. Therefore, the finding was determined to be of very low safety significance.

Enforcement. Cooper Nuclear Station Technical Specification 5.4.1a. states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Revision 2, February 1978, paragraph 9.a., states, in part, that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures or documented instructions. Cooper Nuclear Station Administrative Procedure 0.40, “Work Control Program,” Revision 37, paragraph 2.1, states that “Station maintenance shall be performed using approved instructions, controlled drawing details, or reviewed and approved instructions that comply with applicable codes and standards.” Work order documents associated with safety-related Agastat relay replacement performed under the preventive maintenance program state, “Submit Master Data Change Request to reflect new serial number and Model number. Adjust preventive maintenance Start Date per manufacture date.” Contrary to the above, in 17 cases since February 2003, the licensee staff failed to perform Agastat relay replacement as prescribed by the applicable work order documents in that the preventive maintenance start date was not properly adjusted following Agastat relay replacement. This violation is being treated as a noncited violation (05000298/2003002-01) consistent with Section VI.A of the NRC Enforcement Policy. The licensee staff documented this issue in their corrective action program as Notification 10270855.

Example 2

Introduction. The team identified a finding of very low safety significance (Green) and a noncited violation for the failure to follow Procedure 0.5.OPS, "Operability Review of Notifications/Operability Determination," Revision 18, as required by Technical Specification 5.4.1a.

Description. On March 4, 2002, Resolve Condition Report 2002-0341 was initiated to review Maintenance Rule Function IA-F01, "Supply Reactor Building Critical Loads," and to identify the apparent cause for the pressure retention test failures of instrument air accumulators. Between March 7 and November 9, 2001, Instrument Air Accumulators IA-ACC-263, -265, and -267 (emergency air supply to reactor recirculation motor-generator set heating and ventilation secondary containment isolation valves) and IA-ACC-256H (emergency air supply to Main Steam Relief Valve 71H) failed to meet the as-found acceptance criteria for pressure retention during their pressure-drop tests.

The engineering staff noted that in the past it was acceptable to run the accumulators and related components until a failure was observed and 30 safety-related accumulators did not have preventive maintenance procedures. The licensee staff developed preventive maintenance procedures for all safety-related accumulators as part of TIP Action Plan 5.3.1.2.i, steps 1.a and 1.b. Based on industry experience of o-ring service life, the preventive maintenance procedure included check valve replacement frequency of 7.5 years. The licensee staff planned to start check valve replacement in March 2004.

The failures observed in Instrument Air Accumulators IA-ACC-263, -265, and -267 were attributed to check valve leakage. The check valves are 1/4-inch spring-loaded valves. Licensee personnel found that the o-ring valve seals had become dislodged from their seats, resulting in the valves not sealing tightly. The seals are held in the seat by a silicone-like paste. In the failed valves, the paste dried out, allowing the o-rings to become dislodged. The pressure drop test failure observed in Instrument Air Accumulator IA-ACC-256H was a result of a leaking boundary valve rather than a check valve failure.

During Refueling Outage RE21 (February - April 2003), Cooper Nuclear Station staff identified five accumulator pressure drop test failures. Of the five, only Accumulator IA-ACC-256B, Check Valve IA-CV-18CV, was found to be leaking.

The team evaluated the corrective actions associated with the instrument air check valves and questioned the operability of several valves based on their service life being greater than 7.5 years. These included Valves IA-CV-47CV, IA-CV-48CV, IA-CV-50CV, IA-CV-51CV, IA-CV-52CV, IA-CV-54CV, IA-CV-56CV, and IA-CV-111CV. When questioned about the operability of those check valves, Cooper Nuclear Station staff initially stated in Notification 10271488 that the valves were operable because the associated safety-related accumulators had passed their last surveillance test and there was no information pointing to a degraded or nonconforming condition. However, the team pointed out that, in Resolve Condition Report 2002-0341, Cooper Nuclear Station staff had identified the dried-out silicon paste on the check valve o-rings as the mechanism for allowing the dislodging of the o-ring and subsequent air back-leakage. Licensee personnel stated that the drying out of the silicon paste was a function of service life and the basis for selecting 7.5 years as the replacement frequency. However, the team identified that the above instrument air check valves had been in service beyond 7.5 years, with some check valves having been in service for up to 16 years. Procedure 0.5.OPS, "Operability Review of Notifications/Operability Determination," Revision 18, states that "upon identification of a degraded or non-conforming condition, operability of structures, systems, and components is determined regardless of plant mode in which the equipment is required." The team considered the potential for dried-out silicon paste inside the instrument air check valves to be a degraded condition that brought the operability of the check valves into question. After further review, Cooper Nuclear Station staff declared the eight check valves listed above as inoperable and replaced them. All eight accumulators passed the as-found (which indicated no check valves failures) and as-left pressure drop tests.

Analysis. The performance deficiency associated with this finding is the failure to follow procedures as required by Technical Specifications. The finding impacts the mitigating systems cornerstone and is more than minor based on Example 4.f in Inspection Manual Chapter 0612, Appendix E. Similar to the example, Cooper Nuclear Station staff failed to recognize the degraded condition associated with the age of the instrument air check valves, and when the condition was recognized, eight valves were declared inoperable. Using the Significance Determination Process Phase I worksheet in Inspection Manual Chapter 0609, Appendix A, the finding was determined to be of very low safety significance, since it did not result in the actual loss of a safety function or one train of a safety function for greater than the Technical Specification allowed outage time or screen as potentially risk significant due to a fire, seismic, flooding, or severe weather initiating event.

Enforcement. Technical Specification 5.4.1a. states, in part, that procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Specifically, Regulatory Guide 1.33, Appendix A, Item 1.c, requires procedures for equipment control. Contrary to the above, Cooper Nuclear Station staff failed to follow Procedure 0.5.OPS, which required an operability determination to be performed for degraded conditions of safety systems. The licensee failed to recognize the degraded condition and evaluate operability. Because this failure to perform an operability determination is of very low safety significance and has been entered into the corrective action program as Notification 10271488, this violation is being treated as an noncited violation (Noncited Violation 05000298/2003002-02), consistent with Section VI.A of the NRC Enforcement Policy.

Example 3

Introduction. The team identified a second example of very low safety significance (Green) finding and a noncited violation for the failure to follow Procedure 0.5.OPS, "Operability Review of Notifications/Operability Determination," Revision 18, as required by Technical Specification 5.4.1a. This failure resulted in an inoperable reactor feedwater check valve remaining in service for an undetermined period of time.

Description. The reactor feedwater check valves provide primary containment isolation in the event of fission product release. They also help provide reactor coolant pressure boundary isolation in the event of a feedwater line break. Additionally the outboard reactor feedwater check valves provide an injection flow boundary for high pressure core injection and reactor core isolation cooling. The check valves utilized a Stellite surface as the primary seal for high differential pressures and a secondary soft-seal ring to seat the valve at low differential pressures. The soft-seal ring (soft seat) is essentially an o-ring that fits into a groove in the disc seat. The reactor feedwater check valves were required to meet 10 CFR Part 50, Appendix J, Option B, Type C, local leak rate test criteria.

On November 9, 2001, the local leak rates for three of four reactor feedwater check valves (RF-CV-13CV, -14CV, and -15CV) could not be quantified (>400 scfh) because of excessive back-leakage. The leak rate limit was 25 scfh. Significant Condition Report 2001-1161 was initiated to evaluate the cause of the local leak rate test failures. In Significant Condition Report 2001-1161, Cooper Nuclear Station staff documented a series of local leak rate test failures for the reactor feedwater check valves that ranged from 1983 to 2001. During that time period, at least one of the four reactor feedwater check valves failed each refueling outage, except for Refueling Outage RE17 in 1997. The licensee staff also ascertained that Valve RF-CV-15CV was the most problematic of all the reactor feedwater check valves. With the exception of RE8 and RE17, Valve RF-CV-15CV failed the local leak rate test every outage since 1983. In 2001, the NRC resident inspectors evaluated the history of the reactor feedwater check valve's local leak rate test failures and documented a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI. This violation was tracked as Noncited Violation 05000298/2001007-03.

Significant Condition Report 2001-1161 identified the root cause of the reactor feedwater check valve's failures as an incorrect technical understanding of the dual (soft) seat design. Licensee personnel identified a causal factor that, if removed, could have prevented or lessened the severity of the condition. One causal factor was valve seat out-of-roundness. Corrective actions in Significant Condition Report 2001-1161 included lapping the valve seats and aligning valve hinges. However, Valve RF-CV-15CV continued to have an out-of-roundness condition of up to 0.024 inches. The licensee staff attempted to achieve a satisfactory local leak rate test with only a metal-to-metal seat for Valve RF-CV-15CV, but the leak rate was excessive. Therefore, maintenance personnel re-installed the soft seat and the valve was able to pass the local leak rate test.

On March 5, 2003, during Refueling Outage RE21, Valve RF-CV-15CV failed the as-found local leak rate test, such that testing personnel were not able to quantify the leakage. According to TIP Action 5.3.1.2.b, Cooper Nuclear Station staff, with vendor assistance, performed significant work on the valve internals by replacing the valve disc, seat, and hinge pins and performed line boring. The licensee staff tested Valve RF-CV-15CV with the metal-to-metal hard seat design, but the test was unsuccessful. The original combination of hard and soft seat design was used to pass the local leak rate test.

The licensee staff performed an apparent cause (Resolve Condition Report 2003-0509) for the failure of Valve RF-CV-15CV to pass the local leak rate test in Refueling Outage RE21. The apparent cause described the poor condition of the metal-to-metal hard seats as the reason for the local leak rate test failure. Resolve Condition Report 2003-0509 referred to two reasons for Valve RF-CV-15CV local leak rate test failure. One reason was attributed to the fact that the reactor water clean-up system, when in service, placed a differential pressure of approximately 200 psid on Valve RF-CV-15CV disc. For an extended period of time, this closure force causes the soft seat to permanently deform (very slightly). This deformation reduced the sealing capability of the soft seat and reduced the local leak rate test reliability. The second reason for the Valve RF-CV-15CV local leak rate test failure was due to the as-left, out-of-round condition of its valve seat.

The team determined that a degraded condition existed with Valve RF-CV-15CV following Refueling Outage RE20, which was not addressed by Cooper Nuclear Station staff. At the exit of Refueling Outage RE20, Valve RF-CV-15CV had an out-of-round valve seat, and the team concluded that it was a degraded condition as substantiated in Significant Condition Report 2001-1161. As documented in Resolve Condition Report 2003-0509, the out-of-round condition, in conjunction with the differential pressure of reactor water clean-up, resulted in the as-found local leak rate test failure of Valve RF-CV-15CV at the beginning of Refueling Outage RE21. Licensee personnel stated that they did not believe there was a degraded condition at the exit of Refueling Outages RE20 because of the lapping of the valve seats and discs. The team determined that, following Refueling Outage RE20, Cooper Nuclear Station staff did not address the impact of the out-of-round valve seat on the operability of Valve RF-CV-15CV, as required by Procedure 0.5.OPS.

Analysis. The performance deficiency associated with this finding is the failure to follow Procedure 0.5.OPS, as required by Technical Specification 5.4.1a. The finding impacts the barrier integrity cornerstone and is more than minor using Example 4.f of Inspection Manual Chapter 0612, Appendix E. Similar to the example, this finding involved the failure to adequately correct a significant condition adverse to quality and resulted in an inoperable reactor feedwater check valve being left in service. Using the Significance Determination Phase 1 process worksheet in Inspection Manual Chapter 0609, Appendix A, the finding did not represent a degradation of a radiological barrier function or a degradation of the barrier function of the control room against smoke or toxic atmosphere or an actual open pathway of reactor containment or a reduction of the atmospheric pressure control function of reactor containment. Therefore, the finding was determined to be of very low safety significance.

Enforcement. Technical Specification 5.4.1a. states, in part, that procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Specifically, Regulatory Guide 1.33, Appendix A, Item 1.c, requires procedures for equipment control. Contrary to the above, Cooper Nuclear Station staff failed to follow Procedure 0.5.OPS, which required an operability determination to be performed for degraded conditions for safety systems. The licensee failed to recognize the degraded conditions and evaluate operability. Because this failure to perform an operability determination is of very low safety significance and has been entered into the corrective action program as Notification 10272631, this violation is being treated as the second example of Noncited Violation 05000298/2003002-02.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The team reviewed approximately 150 condition reports, 5 audits, 12 self-assessments, and numerous trending reports described in Section 4OA2 to verify that corrective actions related to the issues were identified and implemented in a timely manner commensurate with safety, including corrective actions to address common cause or generic concerns. A listing of specific documents reviewed during the inspection is included in the attachment to this report.

The team evaluated the timeliness and adequacy of operability determinations and evaluations. The team reviewed corrective actions planned and implemented by the licensee staff and sampled specific technical issues to determine whether adequate decisions related to structure, system, and component operability were made.

(2) Assessment

The team determined that the majority of conditions adverse to quality were effectively resolved. Some exceptions to this determination were noted in the areas of timeliness of corrective actions for two fire protection modifications, continued problems in the area of human performance, inadequate corrective actions for replacement of aging Agastat relays, and recognition of degraded conditions and performing of operability determinations.

In the past two identification and resolution of problems inspection reports, the NRC documented issues with the licensee staff performing operability determinations. In particular, the previous inspection (NRC Inspection Report 05000298/2001010) identified that a number of degraded conditions were found to have not been subjected to operability determinations when criteria were met to do so. The previous team noted that licensee personnel had difficulty with recognizing when operability determinations were required.

During this inspection, the team continued to find similar weaknesses in the licensee staff's ability to conduct operability determinations. In addition, during other routine baseline inspections over the past year, two examples of failure to perform operability determinations for degraded equipment were identified. Corrective actions taken by Cooper Nuclear Station to address this long-standing issue have not been effective and indicate continued problems in this area that need to be addressed.

Example 1

The team determined that the licensee staff had not actively pursued the completion of two fire protection modifications that resulted from two noncited violations identified in NRC Inspection Report 05000298/2001003. These modifications were for the addition of fire detectors in the control room and diesel generator rooms, and replacement of existing sprinkler heads in portions of the reactor building. The licensee staff completed Engineering Analysis EE01-007 on May 9, 2002, which determined the scope of the fire detector modification. In addition, the licensee staff completed Calculations NEDC 01-014, -015, -017 on December 27, 2001, which determined the scope of the sprinkler modification.

The team noted that sprinkler modification Change Evaluation Document 6010844 was not approved until September 11, 2003. The modification was started and completed during the week of September 22-26, 2003. The detector modification Change Evaluation Document 6010935 was not completed at the end of the inspection. Work was scheduled to begin in November 2003.

The team noted that the failure to pursue these modifications resulted in the licensee staff being in noncompliance with their approved fire protection program for almost 2 ½ years. However, compensatory measures in the form of roving fire watches were in place during this time. The team determined from interviews with licensee personnel that the sprinkler and detector modifications were not aggressively pursued until the Technical Program Health Report rated the fire protection program as RED (unacceptable program performance due to these two long-standing modifications not being implemented). This was documented in Notification 0010240864, which was issued on April 10, 2003. Subsequently, a project manager was assigned to oversee these two modifications. Although the licensee’s corrective action could have been more timely, the team did not consider this a violation of requirements since the licensee staff maintained fire watches in the affected plant areas.

Example 2

The inspectors noted several examples in which the licensee's corrective actions for long-standing human performance issues failed to prevent recurrences of similar human performance errors. In one example, the licensee staff identified a negative trend in the configuration control of plant components. Resolve Condition Report 2002-0965 was written on June 6, 2002, to document this trend. The responsible manager assigned a self-assessment to be performed by a root cause evaluator qualified individual. This self-assessment identified inadequacies in prejob briefs as contributing to 36 percent of configuration control errors by the operations department. No corrective actions were recommended or implemented in the area of prejob briefs.

The adverse trend in configuration control errors continued and was identified again in November 2002 in Resolve Condition Report 2002-2374. Another self-assessment identified inadequacies in prejob briefs as a contributing factor in configuration control errors. The recommendations from this self-assessment were entered into the corrective action program under Resolve Condition Report 2003-0328, which included four specific actions for improving prejob briefs. Only two of these actions were implemented; the remaining two were administratively closed with the Operations Manager's approval, as allowed by procedure.

In July 2003, a human performance error occurred while restoring the level control valve for Feedwater Heater A5 to automatic following corrective maintenance. This error led to a loss of feedwater heating and subsequent reactor power transient. This was documented in Significant Condition Report 2003-1432 and a root cause investigation was performed which identified the lack of an adequate prejob brief as a root cause of the transient.

Collectively, these issues represent ineffective corrective actions for human performance errors, one of which contributed to a plant transient.

The inspectors also observed that the licensee staff received 11 noncited violations of Technical Specification 5.4.1a. in the past 18 months for failure to follow procedures. Each of these noncited violation's was sufficiently similar in that human performance errors contributed to the violations. Five of these noncited violations were classified as "significant" in the licensee staff's corrective action program and were the subject of significant condition report's and formal root causes; however, the inspectors were unable to confirm that the licensee staff had formally addressed this negative trend within their corrective action program. Corrective actions had been implemented; however, they were done so, in part, outside of the corrective action program. There was no condition report documenting the trend.

Example 3

Introduction: The team identified a finding of very low safety significance (Green) and a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions." This finding and noncited violation involved a failure to correct a previously identified condition which allowed an Agastat relay in the residual heat removal system (Cooper Nuclear Station-9-RHR-REL-121A) to be replaced under the preventive maintenance program with a replacement relay that was determined to be beyond its approved service life.

Description: On March 17, 2003, Relay CNS-9-RHR-REL-121A was replaced as scheduled and planned in the preventive maintenance program. The intent was to replace the installed Agastat relay, which was older than the qualified life of 10 years from the date of manufacture, with a new relay that would be within the recommended age. However, the relay that was used as the replacement was the same age as the original. The result was that the condition that existed prior to the relay replacement continued to exist after the replacement and the condition was not corrected. This condition was documented on September 18, 2003, as Notification 10270931.

This condition was identified as a result of questioning by the team concerning Agastat relay replacement activities under the preventive maintenance program since February 2003 (see Section 4OA2.(2), Example 2). The licensee's preventive maintenance program required safety-related Agastat relays to be replaced within the qualified life of 10 years from the date of manufacture. This requirement was not met and resulted in Relay CNS-9-RHR-REL-121A being allowed to remain in service beyond the specified service life.

Because of a lack of effective controls of replacement Agastat relays, a replacement relay was issued and installed that was the same age as the original relay. On February 28, 2003, the licensee staff wrote Notification 10229174 to place safety-related Agastat relays that were greater than 8 years old on hold pending an evaluation to determine whether design life limitations could be based on date of installation rather than date of manufacture. Effective controls were not put in place to ensure that relays older than 8 years would not be issued to maintenance personnel for use in the plant. The evaluation to base the design life of these relays on the date of installation rather than the date of manufacture had not been completed.

Analysis: The team determined that this finding was more than minor since if left uncorrected it would become a more significant safety concern. Specifically, the licensee staff failed to correct a condition of a safety-related Agastat relay in service in the residual heat removal system for longer than the vendor recommended and preventive maintenance program required service life. The licensee determined that the operability of the residual heat removal system was not impacted by the age of relay since an operability determination stated that the relay could perform its safety function. This decision was based upon laboratory testing data and no aging Agastat relay failures to date. Using the Significance Determination Process, as described in Inspection Manual Chapter 0609, under the Mitigating System Column, the finding screens as Green since the deficiency was confirmed to have not resulted in a loss of safety function.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," states, in part, that "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected." Contrary to the above, the licensee staff failed to promptly identify and correct a condition where a safety-related Agastat relay in the residual heat removal system was in service for longer than the specified service life and replaced with another relay of the same age. This violation is being treated as a noncited violation (05000298/2003002-03) consistent with Section VI.A of the NRC Enforcement Policy. The licensee staff documented this issue in their corrective action program as Notification 10270855.

Example 4

Introduction: The team identified a finding of very low safety significance (Green) and a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions." This finding and noncited violation involved a failure to correct the continuing problems associated with operability determinations and to effectively implement corrective actions to prevent recurrence of previously identified violations.

Description: During this inspection, the team identified two examples in which licensee personnel failed to recognize degraded conditions and then perform operability determinations (for details see Section 4OA2b, Examples 3 and 4). The instrument air check valves for the safety-related accumulators leaked as a result of o-rings not sealing because of age hardened silicon grease. For Feedwater Check Valve RF-CV-15CV, the licensee staff failed to correct the seat sealing surfaces (since 1983) and, as a result, with the exception of two refueling outages, Check Valve RF-CV-15CV failed the as-found local leak rate test.

While interviewing plant personnel associated with the instrument air accumulators and the feedwater check valve, it became apparent that approximately 10 individuals did not understand degraded conditions and operability. These individuals stated that, since the as-left surveillance test passed, the equipment was operable even though the maintenance history indicated potential degraded conditions and/or a history of repetitive as-found test failures.

Since the 2001 identification and resolution of problems inspection, two additional failures to perform operability determinations were identified in the quarterly integrated inspection reports.

- In NRC Inspection Report 05000298/2002004, the inspectors determined that the licensee staff did not perform an operability determination for the two 250 Vdc safety-related batteries that had five degraded cells.

- In NRC Inspection Report 05000298/2001008, the licensee staff failed to perform an operability determination after identifying that the reactor equipment cooling system was not analyzed for a loss of coolant accident.

Both of the above examples resulted from plant personnel not recognizing degraded conditions even though existing documentation indicated that operability of the components was potentially impacted.

During the 2001 identification and resolution of problems inspection, as documented in NRC Inspection Report 05000298/2001010, the team identified eight examples that occurred in previous inspections and two examples during the inspection where the required operability determinations were not performed. The following two examples were identified during the 2001 inspection.

- On August 28, 2001, operators placed the electrical distribution system in a configuration that rendered both offsite power circuits inoperable. The team determined that the plant configuration would not have allowed the offsite power circuits to auto-transfer during a loss-of-offsite power. Operations and engineering personnel failed to recognize the degraded condition and, therefore, failed to evaluate operability.

- On September 7, 2001, a lighting strike caused a loss of both offsite power sources. The licensee staff determined that the loss-of-offsite power was caused by a fault on the 161 kV Auburn line (nonqualified source of offsite power). During the review of this event, the team noted that a previous engineering evaluation stated that a fault on the 161 kV Auburn line would not cause a failure of the T2 auto-transformer. Based on the team's questioning, the licensee staff found a failed relay, which caused the T2 auto-transformer to isolate contrary to its design. The licensee staff failed to recognize that the switch yard did not operate as designed and, as a result, did not perform an operability evaluation.

The above two examples and many of the eight examples identified in previous inspections of failures to perform operability determinations were a result of plant personnel failing to recognize degraded conditions.

Similarly, the 2000 identification and resolution of problems inspection, as documented in NRC Inspection Report 0500298/2000010, the team identified six examples during the inspection where a potential degraded condition was identified, but the required operability determinations were not performed. The failures to perform operability determinations were a result of plant personnel failing to recognize degraded conditions.

<u>Analysis</u>: The team determined that this finding was more than minor since if left uncorrected it would become a more significant safety concern. Specifically, the licensee staff's failure to recognize degraded conditions and subsequently perform operability determinations could result in continued operation of the facility with systems, structures, and components not capable of performing their intended safety functions.

Corrective actions associated with Noncited Violation 05000298/2001010-05 consisted mainly of changes to Procedure 0.5.OPS, "Operability Review of Notification/Operability Determination." The Strategic Improvement Plan contained Action Plan 5.2.1.2, "Operability Determinations," which was developed to improve recognition and disposition of degraded and nonconforming conditions. Much of the action plan focused on operations department review of notifications for operability impacts and the operability determination process. In addition, Action Plan 5.2.1.2, step 11, developed a 2-day training course which focused on identifying conditions adverse to quality, including degraded and nonconforming conditions. This training was started in the 2nd quarter of 2003 and was completed in November 2003. The training was given to approximately 200 site personnel covering many departments. The current findings and findings in NRC Inspection Report 0500298/2000010 documented that personnel, other than operators, routinely did not recognize degraded conditions, even when information demonstrated otherwise. None of the corrective actions taken have adequately addressed the ability of site personnel to recognize degraded and/or nonconforming conditions.

This issue was determined to have a very low risk significance (Green), because:

- For the instrument air accumulators check valves and Feedwater Check Valve RF-CV-15CV, both systems remained operable and were determined to be of very low risk significance (Green).

- For all other previous examples of not performing operability determinations, all of those examples were determined to be of very low risk significance (Green).

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition." Contrary to the above, the licensee staff failed to take adequate corrective actions to resolve continuing problems associated with performing operability determinations. This violation is being treated as a noncited violation (05000298/2003002-04) consistent with Section VI.A of the NRC Enforcement Policy. The licensee staff documented this issue in their corrective action program as Notification 10282579.

d. Assessment of Safety-Conscious Work Environment

(1) Inspection Scope

The inspectors interviewed 11 individuals from the licensee's staff, which represented a cross section of functional organizations and supervisory and nonsupervisory personnel. These interviews assessed whether conditions existed that would challenge the establishment of a safety-conscious work environment. The team reviewed the summary conclusions of select concerns placed into the licensee's employee concerns program, which provided an alternate method to the corrective action program for employees to raise safety concerns with the option of remaining anonymous. In addition, the team reviewed several safety culture surveys conducted by the employee concerns program.

(2) Assessment

The team identified no findings related to the safety-conscious work environment at the facility. The team concluded, based on information collected and reviewed, that employees were willing to identify safety issues and enter them into a corrective action system or raise the issue through the employee concerns program.

4OA5 Other - Additional Inspection Areas

(1) Inspection Scope

During the course of the problem identification and resolution inspection, the team discovered one issue associated with a Zurn strainer controller modification that was considered a violation. The team reviewed the problem identification, prioritization and evaluation, and the corrective actions for this issue and determined that they were adequate.

(2) Assessment

Example

Introduction. A Green finding and self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion III, was identified for inadequate design control of the service water Zurn strainer control panels. This inadequate design control resulted in the use of nonessential components and loss of configuration control for the strainer control panels.

Description. The service water system is a safety-related system that provides cooling water to several essential heat exchangers, including those in the residual heat removal system and emergency diesel generators. To prevent clogging of the essential heat exchangers, the service water system has traveling screens that prevent debris greater than 3/8-inch diameter from proceeding through the service water system. Also, the service water system has one Zurn strainer, per division, to further filter debris that is greater than 1/8-inch in diameter. The strainer is designed to remove debris during normal, accident, and transient conditions. The differential pressure across the strainer is limited to 15 psid. The strainer is equipped with an automatic backwash feature activated either on a timed cycle, by high differential pressure, or in a continuous mode of operation. If the automatic backwash feature is lost, operators can manually backwash the filter to remove debris from the strainer. The strainer control panels are classified as essential, and they provide the automatic signal for the backwash.

On January 6, 2003, Notification 10218359 was initiated to investigate the cause of the Zurn strainer high differential pressure alarms. During the troubleshooting, Cooper Nuclear Station staff noted the following discrepancies in the Divisions A and B Zurn strainer control panels:

- The reversing motor starter assembly in the Division A strainer control panel was an ITE, while Drawing 48892 showed a Westinghouse starter. Although the ITE starter was an essential component, Cooper Nuclear Station staff could not trace the documents describing its inclusion into the service water strainer control panel.

- The general-purpose relay, designated as RL, and two time-delay relays, TR1 and TR2, were classified as nonessential in both the Divisions A and B strainer control panels. Licensee personnel determined that these nonessential relays have been in the control panels since plant construction.

- Limit switch LS was classified as nonessential in both the Divisions A and B strainer control panels. The limit switch had been installed in the control panels since plant construction.

- The RL relay in the Division A strainer control panel was wired to the sensing circuit board and the relay was Ty-wrapped to the wire raceway (modification to sensing board circuit). Licensee personnel could not identify the design documentation that put the RL relay in this configuration. The RL relay in the Division B strainer control panel was installed on the circuit board.

Licensee personnel determined that if the installed nonessential components failed, then automatic actuation of the backwash feature would be lost, as well as the control room alarms indicating high differential pressure across the strainers. Licensee personnel performed an operability determination which showed that the Zurn strainer control panel was still operable. The team reviewed the operability determination and found it to be adequate. Specifically, the nonessential components were similar in construction, use, and design limitations as the essential components. Licensee personnel initiated a design change under CED 6012680 to: (1) isolate the nonessential relays from the rest of the control panel, (2) replace the nonessential limit switch with an essential limit switch, (3) restore the proper configuration of the RL relay in Control Panel A, and (4) replace the ITE starter with the specified Westinghouse starter.

Analysis. The team determined that Cooper Nuclear Station staff did not implement the appropriate design control measures to maintain design configuration control and to prevent nonessential components from being placed in service in the service water Zurn strainer control panels. The finding is more than minor using Inspection Manual Chapter 0612, Appendix E, Example 3.a. Similar to the example, Cooper Nuclear Station staff failed to implement appropriate design control measures for the service water Zurn strainer control panels, resulting in errors significant enough to require an operability determination and a design change to resolve concerns. Using the significance determination process Phase 1 worksheet in Inspection Manual Chapter 0609, Appendix A, the finding did not result in an actual loss of a safety function or the actual loss of one train of the service water system for greater than its Technical Specification allowed outage time. Also, the finding was not risk-significant from a fire, seismic, flooding, or severe weather initiating event standpoint. Therefore, the finding was determined to be of very low safety significance (Green).

Enforcement. 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established for the selection and review for suitability of application of material, parts, equipment, and processes that are essential to the safety-related functions of systems, structures, and components. Contrary to the above, Cooper Nuclear Station staff allowed nonessential relays and limit switches to be used in the service water Zurn strainer control panels. Additionally, Cooper Nuclear Station staff failed to maintain design configuration control of a reverse motor starter and RL relay for the Division A strainer control panel. Because this failure to maintain design control was determined to be of very low safety significance and has been entered into the corrective action program as Resolve Condition Report 2003-0047, this violation is being treated as an noncited violation (05000-298/2003002-05), consistent with Section VI.A of the NRC Enforcement Policy.

4AO5 Other - Inspection of NRC Confirmatory Action Letter (CAL) and Cooper Nuclear Station TIP

Details

The following documents are available to the public in the NRC Agency-wide Document Access and Management System (ADAMS) using the appropriate accession number. ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

The TIP, Revision 1; dated June 10, 2002; ADAMS Accession Number ML023010136

The TIP, Revision 2; dated November 25, 2002; ADAMS Accession Number ML030340146

CAL dated January 30, 2003; ADAMS Accession Number ML030310263

The TIP consists of a series of individual steps, each with an assigned scheduled completion date. As each step is completed, the licensee staff creates a closure package containing all associated documents, drawings, procedures, etc., that support the closure of that step. An independent reviewer checklist is completed for each step to ensure package completeness and is included in the closure package. The team reviewed the completed closure packages for the steps indicated in this report.

To assess the licensee’s progress in implementing the improvement plan, the inspectors reviewed documents and interviewed personnel responsible for the completed action plan steps to verify that the steps were completed on schedule as defined in the CAL and that the actions taken met the intent of the action plan step. In addition, the team assessed the effectiveness of the improvement plan by reviewing the results of NRC baseline inspections, NRC performance indicators, and licensee performance measures and indicators.

1. **CAL Item 1 - Emergency Preparedness**

Inspection Activities

a. Scope

The licensee had previously completed all emergency preparedness action plan steps addressed in the CAL. The NRC's review of these steps is documented in NRC Inspection Report 05000298/2003009. However, the team performed a review of licensee performance indicators and NRC baseline inspection results to determine effectiveness of the TIP actions associated with Emergency Preparedness.

b. Implementation of Action Plan Steps

All actions had previously been completed and reviewed by the NRC.

c. Performance Assessment

The team reviewed the following licensee performance indicators (these performance indicators are similar to the NRC performance indicators in the Emergency Preparedness Cornerstone):

Indicator	**Performance**	**Trend**
Alert and Notification System Reliability (number of successful siren tests in previous 4 quarters divided by total number of siren tests in previous 4 quarters)	Green - Excellent Performance	Stable
Emergency Preparedness Emergency Response Organization (ERO) Staffing (tracks ERO staffing vacancies to assure adequate personnel to manage the responsibilities of the ERO)	White - Meets Goal	Negative
Emergency Response Organization Drill Participation (measures percentage of key ERO members who have participated recently in proficiency enhancing drills, exercises, training opportunities,	Green - Excellent Performance	Stable

or in an actual event)		
Emergency Response Organization Performance (number of successful emergency opportunities divided by total opportunities in previous 12 months)	White - Meets Goal	Stable

The team determined that the TIP emergency preparedness performance indicators were meeting licensee goals, although the emergency preparedness/emergency response organization performance indicator was indicating an adverse trend. The August 2003 data indicated two vacancies in the emergency preparedness/emergency response organization, which was at the White-Yellow threshold. This represented a negative trend beginning in May 2003 when there were no vacancies.

Two individuals were selected and are currently undergoing qualification for the position of radiological protection technician. Also, the radiological control manager position was vacant because of a temporary assignment, but is being filled by another person currently undergoing qualifications.

The team considered the actions of the licensee to fill these vacancies to be adequate. The licensee also selected additional personnel to fill these positions to add depth in the event of future personnel changes.

The team also reviewed NRC performance indicators and baseline inspection results from an inspection conducted in July of 2003 and determined there were no significant findings.

d. Conclusions

The team reviewed the licensee's performance indicators, NRC performance indicators, and baseline inspection results for emergency preparedness and determined that the licensee staff continues to demonstrate an acceptable level of performance.

2. CAL Item 2 - Human Performance

Inspection Activities

a. Scope

The team reviewed the following completed TIP, Revision 2, action plan steps associated with CAL Item 2, Human Performance:

Action Plan	Title	Steps
5.1.4.1	Human Performance	4, 5a,19, 20a, and 20f

The team reviewed the closure packages and supporting documentation and conducted interviews with various licensee personnel knowledgeable of the specific steps. The team also reviewed the baseline inspection reports and licensee performance measures and performed a review of site performance indicators to evaluate the effectiveness of the TIP actions associated with Human Performance.

b. Implementation of Action Plan Steps

The licensee staff completed the CAL-related improvement plan steps as scheduled, and the actions taken met the intent of the associated steps.

c. Performance Assessment

The team performed a review of six licensee performance indicators associated with Human Performance:

Indicator	**Performance**	**Trend**
Qualification Matrix	Red - Unsatisfactory Performance	Negative
Overtime (% Hours) Year to Date	Red - Unsatisfactory Performance	Stable
Human Performance Event	Yellow - Action Required	Stable
Configuration Control Events	White - Meets Goal	Stable
Human Performance Error Rate	Yellow - Action Required	Positive
OSHA Recordable Injury Rate	White - Meets Goal	Positive

Two of the six indicators were demonstrating unsatisfactory performance, two were trending positive and two indicators remained stable in the yellow and white range. Also, two baseline inspection findings were documented in NRC Inspection Report 05000298/2003006, dated October 30, 2003, indicating continued problems in the area of human performance. The team determined that the TIP action steps implemented during July and August 2003 had provided some improvement in human performance as evidenced by an improving trend in the Human Performance Error Rate performance indicator. Specific actions that have had a positive impact included:

increased use of management observations in the field, maintenance department implementation of job-site specific reviews of human performance tools, a site-wide standdown regarding human performance, and detailed all hands meetings regarding human performance tools. Despite these improvements, two Red indicators, a Yellow indicator, and a White indicator with no improving trend indicate a need for further effort in this area. The licensee is planning to implement additional actions to improve human performance. These activities include a human performance mock-up trainer scheduled to be implemented in November 2003, a paired observation program to establish common standards and alignment on the observation and oversight of field work, formal performance management skills training, meetings for first line supervisors focusing on human performance improvements, and development of departmental human performance improvement plans.

The team also reviewed baseline inspection reports from February to July 2003 and determined that multiple examples of failure to follow procedures by maintenance technicians and operators and inadequate procedures resulted in errors.

For example:

a. A feedwater heater level control valve mispositioning contributed to a loss of feedwater heating and a reactor power transient in July 2003; and

b. The securing of the high pressure coolant injection system by an alternate means not allowed by procedure rendered the automatic initiation of the system inoperable in May 2003.

The team's review of the June 2003 Interim Human Performance Self-Assessment indicated that some site personnel are not convinced that human performance improvements are still needed. Also as noted in Section 40A2c, the corrective actions implemented to date have not been effective in addressing inadequate pre-job briefs, which has been a significant causal factor in many configuration control errors. The licensee staff also indicated that the TIP was going to be revised to add actions to improve the establishment and reinforcement of human performance behavior at the station. The changes had not been implemented at the conclusion of the inspection.

c. Conclusions

The team reviewed the baseline inspection findings, licensee performance measures, NRC performance indicators, and licensee self-assessments for human performance issues and concluded that some improvement has occurred in this area most notably in the area of OSHA (Occupational Safety and Health Administration) recordable injuries. Efforts to improve human performance in other areas has been less effective. Many of the actions to improve and maintain human performance improvements have been scheduled to be implemented in the future. Also a licensee self-assessment completed in June 2003 summarized that the licensee's efforts to improve human performance have been marginally effective.

3. CAL Item 3 - Material Condition and Equipment Reliability

Inspection Activities

a. Scope

The team reviewed the following completed TIP, Revision 2 action plan steps associated with CAL Item 3, Material Condition and Equipment Reliability. The team reviewed the licensee's closure packages and supporting documentation and conducted interviews with various licensee personnel knowledgeable of the specific steps. The team also reviewed baseline inspection reports and licensee performance measures and performed a review of 15 site performance indicators to assess the effectiveness of the TIP actions associated with material condition and equipment reliability.

Action Plan	Title	Steps
5.3.1.1	Equipment Reliability Improvement Plan	3a, 4a, 4c, 4d, 5a, 5b, 5c
5.3.1.2a	Service Water	2b, 3b, 4, 6, 8a, 9a, 9b, 10a, 10b
5.3.1.2.b	Feedwater Check Valves	3, 5, 6, 7
5.3.1.2.c	Offsite Power/Switch Reliability	9, 10, 12, 15, 16
5.3.1.2.d	Feedwater Controls Improvement	1
5.3.1.2.e	Water Sulfates	1, 10, 12, 13
5.3.1.2.g	Primary Containment Vacuum Breakers	1
5.3.1.2.h	Control Room Recorders Obsolescence	2b, 2c2
5.3.1.2.i	Air Systems	1b, 8a
5.3.1.2.k	Optimum Water Chemistry	5

b. Implementation of Action Plan Steps

1. TIP, Revision 2, Action 5.3.1.2.a - Service Water

Electrical Test - On Line

Steps 9a and 9b of Action Plan 5.3.1.2.a were associated with the service water pump motors. Steps 10a and 10b were associated with the service water booster pump motors. Steps 9a and 10a of Action Plan 5.3.1.2.a required that preventive maintenance for each motor be upgraded. Steps 9b and 10b required that the preventive maintenance then be incorporated into the preventive maintenance program. The action plans associated with steps 9a and 10a were accepted and closed by the closure board on June 30, 2003. The action plans associated with steps 9b and 10b were accepted and closed by the closure board on August 14, 2003.

To satisfy action plan steps 9a and 10a, the licensee staff performed an evaluation and identified several preventive maintenance activities that would meet the intent of the action steps. However, the team identified that the licensee staff had failed to specify a performance frequency for the Electrical Test - On Line. The Electrical Test - On Line included a series of tests that were directed at detecting degraded or cracked rotor bars and shorting rings, loose connections on wound rotor windings, and a loose rotor cage. Motor current signature analysis could also detect defective insulation on stator laminators.

Although the licensee staff identified this test as a required preventive maintenance, no performance frequency had been established. The explanation for not specifying the task frequency was that new equipment to monitor the inrush/starting current was being evaluated and, upon satisfactory completion of the evaluation, the preventive maintenance frequency would be generated. This action did not meet the intent of the action step. The deliverable for the step was to schedule the preventive maintenance task and incorporate the preventive maintenance into the preventive maintenance program. The team reviewed the closure package and noted that notification had not been written that would require the task frequency to be incorporated into the preventive maintenance program when the evaluation was complete. Following discussions with the team, the licensee staff initiated Notification 10271101 to address the improper closure of the action step.

2. <u>TIP. Revision 2, Action 5.3.1.2.i - Air Systems</u>

In Action Step 1a, the licensee staff developed a list of check valves and boundary valves for essential accumulators that required preventive maintenance to assure reliability. The licensee staff identified 62 valves that were required to have preventive maintenance established. No preventive maintenance previously existed. The purpose of Action Step 1b was to develop a schedule that specified and implemented appropriate preventive maintenance for components in the instrument air system.

In March 2003, the licensee staff reviewed vendor information, plant-specific failure data, and industry failure data and established a valve replacement interval of 7.5 years. Valves that could be replaced online were scheduled to be replaced in March 2004 and every 7.5 years thereafter. Valves that required a plant shutdown for replacement were planned to be replaced during Refueling Outage 1RE22 (January 2005) and every 7.5 years thereafter. However, in developing the initial valve replacement date, the licensee staff did not consider the actual age of the valves.

The team determined that the licensee staff did not meet the intent of the action step for developing appropriate preventive maintenance for the instrument air check valves. The preventive maintenance initially established by the licensee staff would have allowed components in a degraded condition to remain in service until March 2004, even though the licensee staff identified a degraded condition (aging) in March 2002. The licensee staff did not perform an evaluation to demonstrate that the check valves were acceptable for use beyond 7.5 years of service life. Without intervention by the team, the check valves susceptible to failure due to aging would not have been replaced until the scheduled replacement date of March 2004. For additional details on the instrument air check valves' degraded condition, see Section 4OA2b.(2) of the report.

c. Performance Assessment

The team reviewed the following licensee performance indicators to evaluate performance in the area of Material Condition and Equipment Reliability.

Indicator	**Performance**	**Trend**
Components in Accelerated Testing	Yellow - Action Required	Positive
Control Room Deficiencies	White - Meets Goal	Negative
Forced Loss Rate (18 Mo)	Red - Unsatisfactory Performance	Stable
Long-Term Caution Order	Red - Unsatisfactory Performance	Negative
On-Line Corrective Maintenance Backlog	Green - Excellent	Positive
On-Line Plant Leaks	Green - Excellent	Stable
Overdue Preventive Maintenance	Red - Unsatisfactory Performance	Positive
Risk Significance Failures	Yellow - Action Required	Stable
Safety System Functional Failures	White - Meets Goal	Stable
Safety System Unavailability		
Emerg. AC Power	Green - Excellent	Stable
HPCI	White - Meets Goal	Stable
RCIC	Green - Excellent	Stable
RHR	White - Meets Goal	Stable
System Health	Yellow - Action Required	Positive

Unplanned Entries Into LCO's	Yellow - Action Required	Positive

The team found that 7 of the 15 indicators were demonstrating either Unsatisfactory Performance or Action Required; however, only two indicators were trending in the negative direction, with the rest either stable or trending positive. The team determined that some improvement was evident by the positive trends observed. The team noted that implementation of many of the equipment improvement plans have just started or are scheduled to begin in the latter part of 2003.

A review of baseline inspection results revealed that the licensee continued to experience equipment reliability problems resulting in a forced shutdown and a power reduction.

- On May 26, the reactor was manually scrammed due to high main turbine vibration caused by the failure of a turbine blade.

- On September 29, power was reduced to 25 percent due to the failure of the reactor water level high level trip due to the sticking of the main turbine block assembly.

The following is a discussion of some specific observations in Material Condition and Equipment Reliability performance indicators.

On-Line Corrective Maintenance Backlog

The purpose of this performance indicator was to monitor the corrective maintenance backlog. In July 2003, this indicator was RED due to 188 corrective maintenance items in the backlog. At the end of August 2003, the indicator was GREEN and trending positive with 97 items on the corrective maintenance backlog list.

The licensee staff stated that the improvements in this indicator were due to an increased work focus by the fix-it-now team and a re-screening of all the items in the corrective maintenance backlog. The team determined that most of the improvement in the indicator was due to the re-screening effort completed in August 2003 and not due to an increased rate of work off.

d. Conclusions

The licensee staff completed the CAL related improvement plan steps as scheduled. However, the team identified two instances in which a closed item did not meet the intent of the action plan step. For example, the preventive maintenance associated with the service water and service water booster pumps was not fully implemented prior to closing the action step. Corrective actions developed to replace instrument air check valves were not appropriate since the initial valve replacement would not occur until March 2004, even though a number of check valves were installed in the plant and beyond their service life.

The team reviewed a sample of the performance indicators associated with Material Condition and Equipment Reliability and concluded that, in general, some improving trends have been noted, but more time is required to assess the overall effectiveness of the TIP. Although a number of action steps plan were completed, most of the steps completed pertained to plan development or procurement relative to equipment improvements. As a result, the actions implemented to date have not provided satisfactory performance indicator results in many of the areas. In addition, the licensee continued to experience equipment reliability problems resulting in a forced shutdown and an unplanned power reduction.

4. CAL Item 4 - To Resolve Long-Standing Problems With Plant Modifications and Configuration Control

a. Scope

The team reviewed the following completed TIP, Revision 2, action steps associated with CAL Item 4, Plant Modification and Configuration Control:

Action Plan	Title	Step
5.2.1.2	Operability Determinations	6,8
5.3.3.1	Design Basis Information/Licensing Basis Information Translation Project	9

The team conducted interviews with various licensee staff personnel knowledgeable of the specific steps and reviewed the closure packages and the supporting documentation. In addition, the team reviewed baseline inspection reports and licensee staff performance measures and performed a review of four Site Performance Indicators used to track effectiveness of the TIP actions associated with Plant Modifications and Configuration Control.

b. Implementation of Action Plan Steps

The licensee staff completed the CAL related improvement plan steps as scheduled, and the actions taken met the intent of the associated steps.

c. Performance Assessment

The team performed a review of three licensee performance indicators associated with Plant Modifications and Configuration Control:

Indicator	**Performance**	**Trend**
Drawing and Vendor Manual Change Backlog	Green - Excellent Performance	Stable

Drawing Change Notice On-Time Completion	White - Meets Goal	Stable
Modification Closeout Backlog	White - Meets Goal	Stable

The team noted the three licensee performance indicators were indicating acceptable performance.

The team identified continuing and repetitive problems with the licensee's ability to perform operability determinations for degraded plant equipment. The team identified multiple examples where the licensee failed to perform operability determinations as required by procedures. These examples are discussed in Section 40A2c of this report.

a. Conclusions

The licensee staff completed the CAL-related improvement plan steps as scheduled and also the actions required by the step. An improving trend has been noted as indicated by the licensee's performance indicators. However, additional time is needed in order to determine whether this improving trend in performance can be sustained as evidenced by the recent problems identified in the baseline inspection reports.

Specifically, during this inspection, the team continued to find weaknesses in the licensee staff's ability to conduct operability determinations. In addition, during other routine baseline inspections over the past year, two examples of failure to perform operability determinations for degraded equipment were identified. Corrective actions taken by Cooper Nuclear Station to address this long-standing issue have not been fully effective and indicate continued problems in this area that need to be addressed.

5. CAL Item 5 - To Resolve Long-Standing Problems With The Corrective Action Program

a. Scope

The team reviewed the following TIP, Revision 2, action plan steps associated with CAL Item 5, Corrective Action Program, Utilization of Industry Operating Experience, and Self Assessments:

Action Plan	Title	Steps
5.2.7.1	Improve Use of CAP (Corrective Action Program) to Effectively Resolve Station Problems	1k, 5b, 5c
5.2.7.2	Root Cause Investigation and Corrective Action Effectiveness	5, 10, 11, 12

The team reviewed the closure packages and supporting documentation and conducted interviews with various licensee personnel knowledgeable of the specific steps. The team also reviewed baseline inspection reports and licensee performance measures and performed a review of five licensee performance indicators used to track effectiveness of the TIP actions associated with the Corrective Action Program, Utilization of Industry Operating Experience, and Self-Assessment.

b. Implementation of Action Plan Steps

The licensee staff completed the CAL-related improvement plan steps as scheduled, and action taken met the intent of the associated step.

c. Performance Assessment

The team performed a review of the five site performance indicators used to track effectiveness of the TIP actions associated with the Corrective Action Program, Utilization of Industry Operating Experience, and Self-Assessments. Specifically, the team reviewed the following indicators:

Indicator	**Performance**	**Trend**
Corrective Action Program Performance Index (composite index of overall CAP program performance, including root cause quality, apparent cause quality, root cause on time completion and CAP backlog)	White - Meets Goal	Stable
Timeliness of Cooper Nuclear Station Response to Industry Issues (tracks resolution of root cause fixes assigned for operating experience applicability)	White - Meets Goal	Positive
Significant Condition Report On-Time Completion (determines the stations ability to complete root cause actions within their originally scheduled due date)	Red - Unsatisfactory Performance	Negative

Significant Operating Experience Report Implementation (monitors SOER open recommendations to improve recommendation implementation timeliness)	Yellow - Action Required	Negative
Corrective Action Program Self-Identification (tracks the percent of problems self-identified by CNS organization)	Green - Excellent Performance	Positive

The team noted that two of the five performance indicators demonstrated performance that indicated either unsatisfactory performance or action required with a negative trend. The other indicators met or exceeded the licensee performance goals and showed a positive or stable trend. The team performed a review of the five performance indicators to determine if any significant change was evident from July 2002 to July 2003. The corrective action program self identification and timeliness of Cooper Nuclear Station Response to Industry Events performance indicators have both shown sustained improvement and continue to perform at or above the licensee goal. However, the other three performance indicators have remained essentially the same, with improvements then setbacks with no clear trend of improvement.

Inspection of the licensee's ability to identify and resolve problems revealed that issues were adequately identified by the licensee staff. While the majority of conditions adverse to quality were effectively resolved, exceptions were noted in the areas of timeliness of corrective actions for two fire protection modifications, continued problems in the area of human performance, inadequate corrective actions for the replacement of aging relays, and recognition of degraded conditions and the performance of operability determinations (see Section 4OA2).

d. Conclusions

The licensee staff completed the CAL-related improvement plan steps as scheduled and the actions taken met the intent of the associated steps.

In the area of effectiveness of problem identification, the team determined that problems were adequately identified and entered into the corrective action program, with some exceptions. The team identified a number of problems with prioritization and evaluation of issues and identified that Cooper Nuclear Station personnel continued to have problems with determining when operability determinations were required. However, the team noted a significant improvement in the ownership and knowledge of the corrective action program by the Condition Review Group and Corrective Action Board. Finally, in the area of effectiveness of corrective actions, the team determined the majority of conditions adverse to quality were effectively resolved. Some exceptions to this determination were noted in the area of timeliness for some fire protection modifications and continued problems in the area of human performance.

6. CAL Item 6 - Engineering Programs

Inspection Activities

a. Scope

Since the last quarterly inspection, the licensee completed one action plan step associated with this CAL item. Inspection of the licensee's actions to complete this step was conducted from October 6-10, 2003, and will be documented in NRC Inspection Report 05000298/2003011. However, the team performed a review of three performance indicators used to track effectiveness of the TIP actions associated with Engineering Programs.

b. Implementation of Action Plan Steps

The team did not review any action plan steps under this CAL item during this inspection.

c. Performance Assessment

The team reviewed the following performance indicators:

Indicator	**Performance**	**Trend**
Overdue Preventive Maintenance	Red - Unsatisfactory	Positive
Cooper Nuclear Station Program Health	Yellow - Action Required	Positive
Engineering Inventory	Yellow - Action Required	Positive

The team noted that the licensee's Recovery Plan (Notification 10241598) issued in April 2003 resulted in a positive trend which has resulted in a change from Red to Yellow in the Engineering Inventory performance indicator. The program health performance indicator has steadily improved and the licensee staff expects this indicator to be white by the end of the 4th quarter 2003. The overdue preventive maintenance performance indicator is still Red; however, the licensee staff has instituted corrective actions (Notification 10246852) for the adverse trend that was noted in April 2003. This performance indicator has been steadily trending positive since April 2003, and as of September 2003 all overdue preventive maintenance actions were completed. In addition, the team's review of baseline inspections indicated no adverse trends in this area.

d. Conclusions

The team reviewed the performance indicators and baseline inspections for engineering programs and determined an improving trend has been noted; however, more time is required to assess whether the effectiveness of the actions will actually ensure sustained improved performance.

4AO6 Exit Meeting

On November 4, 2003, a public meeting was held to present the results of the inspection to Mr. Minahan and other members of the licensee staff. The licensee staff acknowledged the inspection results.

The team asked the licensee staff whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee staff and is a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a noncited violation.

- See Section 4OA2a of the report for details.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

C. Blair, Engineer, Licensing
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J. Christensen, Plant Manager, Acting Site Vice President
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P. Flemming, Manager, Risk and Regulatory Affairs
J. Fox, Forced Outage/Lead Duty Coordinator
T. Hottavy, Manager of Equipment Reliability Department
M. Kaul, Operations Support Specialist
G. Kline, General Manager, Engineering
D. Knox, Manager, Maintenance
D. Meyers, General Manager Site Support
S. Minahan, Acting Site Vice President
D. Montgomery, Human Performance Coordinator
E. Plettner, Engineer Technician
A. Passwater, Senior Consultant
J. Sumpter, Senior Engineer, Licensing
B. Toline, Manager, Root Cause Analysis
C. Warren, Vice President of Nuclear Programs

ITEMS OPENED AND CLOSED

Opened and Closed

05000298/2003002-01	NCV	Agastat Relay Replacement Procedural Violations [Section 4OA2b.(2)]
05000298/2003002-02	NCV	Two Examples of Failure to Perform Operability Determinations [Section 4OA2b.(2)]
05000298/2003002-03	NCV	Agastat Relay Replaced with Relay Beyond Service Life [Section 4OA2c.(2)]
05000298/2003002-04	NCV	Ineffective Corrective Actions Taken for Operability Determination Concerns [Section 4OA2c.(2)]
05000298/2003002-05	NCV	Loss of Design Control for the Service Water Zurn Strainers [Section 4OA5(2)]

LIST OF DOCUMENTS REVIEWED

Plant Procedures

Document	Title	Revision
EDP-26	Program Health Reporting Desk Guide	0
0-CNS-12	CNS Technical Program Administration	9
0-CNS-25	Self-Assessment	12
0-HP-POLICY	Human Performance Policy	2
0-HP-IMPLEMENT	Human Performance Policy Implementing Procedure	1
0.5	Conduct of the Problem Identification and Resolution Process	39
0.5.CAER	Corrective Action Effectiveness Reviews	3
0.5.EVAL	Preparation of Condition Reports	2
0.5.NAIT	Corrective Action Implementation and Nuclear Action Item Tracking	18
0.5.OPS	Operability Review of Notifications/Operability Determination	18
0.5.PIR	Problem Identification, Review, and Classification	12
0.5.ROOT-CAUSE	Root Cause Analysis Procedure	0
0.5.TRND	Trending of Problem Identification Report Results	2
0.10	Operating Experience Program	13
0.27.2	Maintenance Rule a(1) Evaluation and Goal Setting	
0.40	Work Control Program	37
2.0.12	Operator Challenges	4
2.2.71	Service Water System	66
3.28.2	Inservice Inspection Pressure Test Program Implementation	9
3.4	Configuration Change Control	34C1
3.4.4	Temporary Configuration Change	2
5.3GRID	Degraded Grid Voltage	7
6.1Service water.101	Service Water Surveillance Operation (Div 1) (IST)	16

Document	Title	Revision
6.2Service water.101	Service Water Surveillance Operation (Div 2) (IST)	16
7.0.2	Preventive Maintenance Program Implementation	27
7.0.4	Conduct of Maintenance	24
7.0.5	Post-Maintenance Testing	22
7.0.14.2.2	Oil Sampling	2
7.3.16	Low Voltage Relay Removal and Installation	15
7.3.24.1	EGP Relay Testing and Installation	5

Drawings

Document	Title	Revision
Drawing 2006	Flow Diagram - Circulating, Screen Wash & Service Water Systems, Sheet 1	N47
Drawing 48892	592A Stain-O-Matic Control Panel for Intermittent Operation	N03

Work Orders

4160511	4236704	4275988	4314541	4319797
4183990	4267868	4314334	4314574	4326229
4183991				

Departmental Dispositions

10125886
10168928
10178736

Significant Condition Reports

2001-1161	2002-2655	2003-0356	2003-0691	2003-1432
2002-0330	2003-0010	2003-0431	2003-1169	
2002-1455	2003-0350			

Notifications

10073757	10088309	10126149	10150052	10156239
10078580	10091859	10127948	10150053	10161005
10078606	10122708	10132205	10150064	10181513
10078607	10125886	10145238	10153092	10181964

10183273	10233007	10242354	10263782	10271020
10184554	10233008	10242896	10263783	10271021
10184948	10233008	10245775	10263845	10271023
10196269	10233009	10247292	10263846	10271034
10205722	10233012	10250802	10264178	10271035
10212620	10233013	10250806	10269090	10271036
10218359	10233065	10251626	10269421	10271037
10221066	10233074	10251628	10269477	10271038
10224963	10233185	10251630	10270484	10271039
10229174	10233188	10256780	10270855	10271040
10229655	10233466	10257074	10270931	10271488
10230802	10234445	10258179	10270972	10271488
10231045	10234948	10263090	10271014	10271541
10231049	10240864	10263377	10271016	10271542
10232991	10241033	10263378	10271018	10271603
10233006	10241598	10263637		

Resolve Condition Reports

1998-0952	2001-1397	2002-1612	2003-0149	2003-0636
2000-0720	2001-1478	2002-2084	2003-0214	2003-0931
2001-0969	2001-1505	2002-2246	2003-0286	2003-0979
2001-0225	2002-0715	2002-2415	2003-0287	2003-0981
2001-0317	2002-0626	2002-2525	2003-0326	2003-1030
2001-0448	2002-0341	2003-0401	2003-0327	2003-1090
2001-0502	2002-0576	2003-0047	2003-0328	2003-1102
2001-0842	2002-0756	2003-0928	2003-0394	2003-1163
2001-0921	2002-0881	2003-1057	2003-0405	2003-1200
2001-1189	2002-0965	2003-0143	2003-0522	

Audits and Assessments

Document	Title	Revision/Date
Maintenance Department Self-Assessment Report		Second Quarter 2003
Equipment Reliability Department On-Going Self-Assessment Report Second Quarter 2003		August 29, 2003
Independent Quality Assurance Program Audit NPPD - Cooper Nuclear Station 03-10		
Maintenance Department Self-Assessment Report		Second Quarter 2003

Document	Title	Revision/Date
Operations Department Self-Assessment Report		First Quarter 2002
Operations Department Self-Assessment Report		Second Quarter 2002
Operations Department Self-Assessment Report		First Quarter 2003
Operations Department Self-Assessment Report		Second Quarter 2003
Quality Assurance Surveillance Report S408-0102	Continuous Improvement Program	December 20, 2001
Quality Assurance Audit Report 02-12	Continuous Improvement Program	Revision 1/January 24, 2003
Quick Hit Report QH03139	Human Performance Progress Assessment	September 22, 2003
Quick Hit Report QH03142	Corrective Action Program Progress	September 23, 2003
Self-Assessment SA 02008	Operations Department Corrective Action Program Effectiveness	
Self-Assessment SA 02012	Design Changes	
Self-Assessment SA 03022	1st Quarter 2003 TIP 5.2.7.1 Assessment	
Self-Assessment SA 03024	TIP Action Plan 5.2.7.3 Interim Self Assessment	
Self-Assessment SA 03035	Interim Effectiveness Assessment for the Human Performance Improvement Plan (TIP Action Plan 5.1.4.1)	

Licensee Correspondence

Document	Title	Revision/Date
Letter SQA030039	From Mr. Richard Gibson, Cooper Nuclear Station, to Mr. Kent Huber, Flowserve Corporation	June 16, 2003

Operating Experience Reports

Document	Revision
BWRVIP-03, Reactor Vessel and Internals Examination Guidelines	5
General Electric Service Information Letters 652	1
Information Notice 02-022, Degraded bearing surfaces in GM/EMD EDGs	
Information Notice 02-034, Failure of safety-related circuit breaker external auxiliary service water switches at Columbia Generating Station	
Information Notice 03-003, Inadequately Staked Capscrew Renders Residual Heart Removal Pump Inoperable	
OE15869, MCC breaker tripped due to binding of auxiliary contacts	
Part 21 2002-05, Cutoff Service Water Switch Used in Model AK-15, AK-25, and AKR-30 Electrical/Manual Operated Circuit Breaker	
Part 21 2003-10, Failed circuit breakers manufactured by ABB and retrofitted by Westinghouse for Class 1E applications	
Part 21 2003-02, Whiting Corporation crane components potentially significantly overstressed	1
SIL 642, CR105X Auxiliary contact failures	1
SOER 1986-3, Recommendation 1, Check valve failures or degradation	
SOER 2001-1, Recommendation 2, Work in high noise areas and exceeding EAD alarm setpoint due to not hearing EAD alarm	
SOER 03-1, Recommendation 5, Review modification process used to implement changes to emergency power systems to ensure that rigorous modification controls are applied.	

Other Documents

CARB (Corrective Action Review Board) Presentation slides title “CAP Trend Report, Operations Department, Third Quarter 2002," dated November 15, 2002

CARB Meeting Agenda dated September 16, 2003

CARB Presentation slides title “Quarterly On-Going Self-Assessment Report, Operations Department, Fourth Quarter 2002", dated January 16, 2003

Cooper Nuclear Station Diesel Generator System Health Report dated September 4, 2003

Cooper Nuclear Station Operations Log for May 7-8, 2003

Cooper Nuclear Station Site Event Free Clock Events for January 4, 2002, through August 25, 2003

Cooper Nuclear Station Technical Program Health Report for CNS Fire Protection Program for August 2003

Change Evaluation Document 6010844, “RRMG Sets Sprinkler Systems Upgrade,” dated September 11, 2003

Design Change Package CED 2000-0015, “Service Water Pump Column Repair,” Revision 0

Dose Summary for RWP 20031005 from 7/01/03 to 9/19/03, dated September 19, 2003

EPRI Postmaintenance Testing: A Reference Guide, Final Report, April 1991

Engineering Evaluation EE01-007, “Fire Detector Location and Spacing,” dated May 9, 2002

Engineering Evaluation EE01-008, “Assessment of RJA Hydraulic Calculations for CNS Sprinkler Systems,” dated March 27, 2001

Engineering Evaluation EE 02-47, “Permanent Change Documenting Belzona Coating of Specific Internal Areas of Service Water Pump D Intermediate and Lower Columns,” Revision 0

List of fire protection system impairments as of September 18, 2003

Management Performance Review Meeting dated September 22, 2003

Maintenance Department Performance Indicators for August 2003

Operator Workaround Data Base report dated September 23, 2003

Plant Engineering Department System Health Report dated June 27, 2003

Problem Identification Reports (CRG Meeting), September 19, 2003

Status of Maintenance Rule Functions Service Water-f10 for July 2002

Status of Maintenance Rule Functions Service Water-f10d, Service Water-SD1, Service Water-SD2, Service Water-SD3, Service Water-SD4,

Service Water-SD5, Service Water-SD6 and Service Water-0SD7 for July 2002

Status of Maintenance Rule Functions Service Water-F10 for July 2003

Status of Maintenance Rule Functions Service Water-F10D, Service Water-SD1, Service Water-SD2, Service Water-SD3, and Service Water-SD4,

Service Water-SD5, Service Water-SD6, and Service Water-0SD7 for July 2003

Service Water Switchyard Plant Health Committee Meeting Report, dated August 18, 2003

Vibration Test Data (historical) for pump's Service Water-P-A and Service Water-P-B

Strategic Improvement Plan, Revision 2, Step Closure Documents

Action Plan	Step	CAP ID, Revision 2
5.1.4.1	4	Resolve Condition Report 2002-2410 Action 5
5.1.4.1	5a	Resolve Condition Report 2002-2410 Action 6
5.1.4.1	19	
5.2.1.1	20F	Resolve Condition Report 2002-2415 Action 46
5.3.1.1	3a	Resolve Condition Report 2002-2435 Action 6
5.3.1.1	4a	Resolve Condition Report 2002-2435 Action 12
5.3.1.1	4c	Resolve Condition Report 2002-2435 Action 14
5.3.1.1	4d	Resolve Condition Report 2002-2435 Action 15
5.3.1.1	5a	Resolve Condition Report 2002-2435 Action 17
5.3.1.1	5b	Resolve Condition Report 2002-2435 Action 18
5.3.1.1	5c	Resolve Condition Report 2002-2435 Action 19
5.3.1.2a	2b	Resolve Condition Report 2002-2436 Action 4
5.3.1.2a	3b	Resolve Condition Report 2002-2436 Action 6
5.3.1.2a	4	Resolve Condition Report 2002-2436 Action 7
5.3.1.2a	6	Resolve Condition Report 2002-2436 Action 9
5.3.1.2a	8a	Resolve Condition Report 2002-2436 Action 11
5.3.1.2a	9a	Resolve Condition Report 2002-2436 Action 15
5.3.1.2a	9b	Resolve Condition Report 2002-2436 Action 16
5.3.1.2a	10a	Resolve Condition Report 2002-2436 Action 17
5.3.1.2a	10b	Resolve Condition Report 2002-2436 Action 18
5.3.1.2.b	3	Resolve Condition Report 2002-2437 Action 4
5.3.1.2.b	5	Resolve Condition Report 2002-2437 Action 6
5.3.1.2.b	6	Resolve Condition Report 2002-2437 Action 7
5.3.1.2.b	7	Resolve Condition Report 2002-2437 Action 8
5.3.1.2.c	9	Resolve Condition Report 2002-2438 Action 10
5.3.1.2.c	10	Resolve Condition Report 2002-2438 Action11
5.3.1.2.c	12	Resolve Condition Report 2002-2438 Action 13
5.3.1.2.c	15	Resolve Condition Report 2002-2438 Action 16
5.3.1.2.c	16	Resolve Condition Report 2002-2438 Action 17
5.3.1.2.d	1	Resolve Condition Report 2002-2439 Action 2
5.3.1.2.e	1	Resolve Condition Report 2002-2440 Action 2
5.3.1.2.e	10	Resolve Condition Report 2002-2440 Action 11
5.3.1.2.e	12	Resolve Condition Report 2002-2440 Action 12
5.3.1.2.e	13	Resolve Condition Report 2002-2440 Action 13
5.3.1.2.g	1	Resolve Condition Report 2002-2442 Action 2

5.3.1.2.h	2b	Resolve Condition Report 2002-2443 Action 6
5.3.1.2.h	2c2	Resolve Condition Report 2002-2443 Action 8
5.3.1.2i	1b	Resolve Condition Report 2002-2444 Action 3
5.3.1.2i	8a	Resolve Condition Report 2002-2444 Action 12
5.3.1.2.k	5	Resolve Condition Report 2002-2446 Action 13
5.2.1.2	6	Resolve Condition Report 2002-2416 Action 7
5.2.1.2	8	Resolve Condition Report 2002-2416 Action 8
5.3.3.1	9	Resolve Condition Report 2002-2448 Action 10
5.2.7.1	1k	Resolve Condition Report 2002-2429 Action 12
5.2.7.1	5b	Resolve Condition Report 2002-2429 Action 17
5.2.7.1	5c	Resolve Condition Report 2002-2429 Action 18
5.2.7.2	5	Resolve Condition Report 2002-2430 Action 6
5.2.7.2	10	Resolve Condition Report 2002-2430 Action 14
5.2.7.2	11	Resolve Condition Report 2002-2430 Action 15
5.2.7.2	12	Resolve Condition Report 2002-2429 Action 16

Information Request 1
Cooper Nuclear Station PIR Inspection (IP 71152; Inspection Report 05000298/2003002)

The inspection will cover the period of August 2001 through June 2003. All requested information should be limited to this period unless otherwise specified. If possible, please provide all information in the electronic format, preferably on CDs.

Please provide the following information to Greg Werner in the Region IV Arlington office by June 30, 2003:

1. Summary list of all condition reports of significant conditions adverse to quality open or closed during the period

2. Summary list of all open condition reports which were generated during the period

3. Summary list of all open condition reports which were generated prior to the latest refueling outage

4. Summary list of all condition reports closed during the specified period

5. A list of all corrective action documents that subsume or "roll-up" one or more smaller issues for the period

6. List of all root cause analyses completed during the period

7. List of all apparent root cause analyses completed during this period

8. List of plant safety issues raised or addressed by the employee concerns program during the period

9. List of action items generated or addressed by the plant safety review committees during the period

10. All quality assurance audits and surveillances of corrective action activities completed during the period

11. A list of all quality assurance audits and surveillances scheduled for completion during the period, but which were not completed

12. All corrective action activity reports, functional area self-assessments, and non-NRC third-party assessments completed during the period

13. Corrective action performance trending/tracking information generated during the period and broken down by functional organization

14. Current revision of the corrective action, root cause analysis, and incident investigation procedures.

15. Any additional governing procedures/policies/guidelines (such as desk top guides) for:

    a. Condition Reporting
    b. Corrective Action Program
    c. Root Cause Evaluation/Determination

16. Condition Reports or other actions generated for each of the items below:

    a. All licensee event reports issued during the period

    b. All licensee event reports closed during this period

    c. Noncited violations and violations issued during this period

17. Safeguards event logs for the period (may review onsite)

18. Radiation protection event logs

19. Current system health reports or similar information

20. Current predictive performance summary reports or similar information

21. Corrective action effectiveness review reports generated during the period

22. Outage maintenance that was not done for whatever reason

23. Rework of maintenance performed from last outage during this forced outage

Information Request 2 - August 2003
Cooper Nuclear Station PIR Inspection (IP 71152; Inspection Report 05000285/2003002)

The inspection will cover the period of August 1, 2001, through June 30, 2003 All requested information should be limited to this period unless otherwise specified. If possible, please provide all information in the electronic format, preferably on CDs.

Please provide the following information to Greg Werner in the Region IV Arlington office by August 28, 2003:

1. Copies of all open condition reports (entire condition report with actions) that are greater than 2 years old

2. How are you measuring performance improvements/results for the CAL Action Items? Would like information on how these actions are being tracked

3. TIP Effectiveness Reviews

4. ALL QA audits and self-assessments since November 2002

5. Copy of TIP

6. TIP Action Plan Steps ready for closure and the associated PIs (hard copy) (Wayne Walker has already requested from Jim Sumpter)

7. USA Safety Culture Survey and associated Cooper Nuclear Station actions (assume these would be notifications)

8. Preventive maintenance optimization plan

9. Summary table (brief description and tracking number) of the engineering backlog - approximately 2000 items?

10. Copies of roll-up CRs (the entire Condition Report, including associated actions): Notifications 10224987, 10228822, 10242424, & 10243700

11. Copy of deferred outage maintenance on HPCI Terry Turbine -> preventive maintenance deferral justification and Work Order 4223203.

12. Packages for LERs 2001-07, 2002-01 (and Significant Condition Report 2002-2000), 2003-01 (and Significant Condition Report 2003-0691), and 2003-03.

13. Packages for the following OER: RIS 2003-06, IN 2003-03 (and Resolve Condition Report 2003-0245), IN 2002-034, 2002-026 (and Resolve Condition Report 2002-1483), IN 2002-022 (and DD 10210267), IN 2002-06, Part 21 2002-05, Part 21 2003-02-01 (and Resolve Condition Report 2003-0214), Part 21 2003-10

14. Notifications (the entire Condition Report, including associated actions):

DD 10125886	RCR 2001-0842	RCR 2002-1781	RCR 2003-0401	SCR 2002-0330
DD 10168928	RCR 2001-0921	RCR 2002-1872	RCR 2003-0412	SCR 2002-1455
DD 10174081	RCR 2001-1189	RCR 2002-2084	RCR 2003-0414	SCR 2002-2655
DD 10178736	RCR 2001-1397	RCR 2002-2374	RCR 2003-0484	SCR 2003-0010
DD 10183273	RCR 2001-1505	RCR 2003-0047	RCR 2003-0636	SCR 2003-0297
DD 10207842	RCR 2002-0504	RCR 2003-0143	RCR 2003-0798	SCR 2003-0297
DD 10210267	RCR 2002-0576	RCR 2003-0149	RCR 2003-1057	SCR 2003-0691
DD 10224303	RCR 2002-0715	RCR 2003-0232	RCR 2003-1079	SCR 2003-0713
DD 10240864	RCR 2002-0756	RCR 2003-0254	RCR 2003-1090	SCR 2003-0770
DD 10244525	RCR 2002-0957	RCR 2003-0286	RCR 2003-1102	DD 10166564
Notif 10180712	RCR 2002-1493	RCR 2003-0288	RCR 2003-1111	
Notif 10230205	RCR 2002-1556	RCR 2003-0310	RCR 2003-1216	

15. NRC Findings/Violations

- Finding 02-03
- Finding 01-10
- Noncited Violation 03-05-01 (Significant Condition Report 2002-2655 and Significant Condition Report 2002-0010)
- Noncited Violation 03-05-02 (Significant Condition Report 2003-0297)
- Noncited Violation 03-05-03 (Significant Condition Report 2003-0713)
- Noncited Violation 03-04-01
- Noncited Violation 03-04-03
- Noncited Violation 02-04-01
- Noncited Violation 02-02-01
- Noncited Violation 01-02-04
- Noncited Violation 01-07-03
- Noncited Violation 03-04-04
- Noncited Violation 01-07-06
- Noncited Violation 02-03-03 (Significant Condition Report 2002-1455)

16. Miscellaneous Items

- DG system health report shows material condition red - any additional details and/or the associated notifications

- EE-DC system health report shows one open GL 91-18 issue - would like a copy of your 91-18 evaluation

- EE-service water switchyard system health report shows maintenance rule performance is red - any additional details and/or associated notifications

- Instrument air system health report shows maintenance rule performance is yellow because of essential accumulator check valve/boundary valve leakage - any additional details and/or associated notifications; any operability evaluations

- Service water system health report shows service water is red in three areas - any additional details and/or associated notifications

Information Request 3 - Prep Week
Cooper Nuclear Station PIR Inspection (IP 71152; Inspection Report 05000285/2003002)

Please have all requested information available on September 15, 2003. Please sort the information by inspector. Electronic or hard copy of the material is requested.

Terry Jackson - Requested Information

1. *Reactor Feedwater Check Valves*

    a. Valves that failed the local leak rate test for the past 2 outages
    b. SOER 86-3

2. *Security Access Control*

    a. Notification 10184948
    b. Security Procedure 2.14

3. *Service Air System*

    a. Resolve Condition Report 2003-1057 - the full version, not just the closeout document

4. *Service Water System*

    a. Proposed Alternative Provisions for ASME Section XI Relief Request PR-06
    b. Procedure 3.28.2
    c. Procedures 6.1 Service water.101 and 6.2 Service water.101
    d. Maintenance Procedure 7.2.1
    e. Notification 10156239.

5. *Large Number of CED Modifications*

    a. Self-Assessment 02012 (Design Changes)

6. *Instrument Air System*

    a. Need the following Notifications: 10145238, 10231045, 10231049, 10232991, 10233065, 10233074, 10233466, and 10234445

    b. Resolve Condition Reports 2002-0341 and 2003-0928

7. *Failure to Reduce Power*

    a. Significant Condition Report 2003-0356

Interviews

1. *Long-standing Equipment Issues*

    a. Talk to the person who wrote Resolve Condition Report 2002-0715 to find out what other long-standing equipment issues they were talking about.

    b. Talk to someone on the corrective actions to the reactor feedwater Pump B turbine issue discussed in Resolve Condition Report 2002-0715. Discussion would include testing of the feedwater pump turbine and subsequent performance.

2. *Service Water System*

    a. Someone to talk about the corrective action for the nonessential components in the Zurn strainer

    b. Someone to talk about the corrective action for the coating that was introduced into the service water pump suction piping and was the issue around Noncited Violation 02-02-01

3. *Reactor Equipment Cooling System*

    a. Set up an interview with John Meyers, who initiated the DD 0178736. Have him bring system descriptions and appropriate drawings to discuss the issue and get a better understanding.

Vincent Gaddy

1. Significant Condition Report 2001-1161

2. Performance Criteria Basis Document (Maintenance Rule Document) - referenced in TIP 5.3.1.2.k

3. TIP Closure Review Board Charter

4. Interview the TIP Action Plan owners for all TIPs that we are reviewing this time (both Vincent and Wayne)

Tom Farnholtz

Heat up Rate -

1. Notification 10234948

Service water radiation monitor -

1. CED 6005412

Oil sampling -

1. Procedure 7.0.14.2.2 Rev 2
2. Resolve Condition Report 2002-1612

RHR-MOV-MO38A -

1. Procedure 7.2.44.7
2. PIR 3-52614

HPSI-MOV-MO16 -

1. RIS 2001-15

REC-MOV-697MV and REC-MOV-698MV -

1. NEDC 91-243

SOER 2001-1 -

1. Significant Condition Report 2003-0350
2. SOER 2001-1 Recommendation 2

Interviews

The following list of people was obtained from the supplied documents for each issue. What is needed is to talk to a knowledgeable individual for the stated issue. This person may or may not be the specified individual. In addition, multiple interviews may be required to address different aspects of a single issue. These additional interviews will be requested as soon as possible.

1) Raymond J. Dyer

2) Mark S. Kaul

3) Wes Frewin

4) Need to talk to a person knowledgeable of the oil sampling program

5) Anthony J. Scaia

6) Mark R. Fletcher

7) Linda R. Dewhirst

8) Duane J. Weninger

9) Scott S. Freborg

10) David C. Shrader

11) Need to talk to the person responsible for implementing the recommendations of SOER 2001-1

12) Need to talk to a person knowledgeable of the procedures used to mitigate ice accumulation in the river

Greg Werner

1. Interview Safety Concerns manager about program, and review recent files. Explain what has been done in this area associated with the TIP.

2. The current performance indicators.

3. List of previous and current performance indicators. Show me the changes - include deletions, modifications, and new PIs. I would like a copy of the chart used during the PI meeting in the Region yesterday, 9/8.

4. List of PIs used to assess the CAL items. Would like a list of previous and current PIs used to assess each CAL item.

5. PI basis or background document that explains each PI in detail.

6. Review and discuss recent large decrease in on-line corrective maintenance backlog.