April 16, 2002

EA-02-010

Mr. A. C. Bakken III
Senior Vice President
Nuclear Generation Group
American Electric Power Company
500 Circle Drive
Buchanan MI 49107

SUBJECT: D. C. COOK NUCLEAR POWER PLANT, UNITS 1 AND 2
NRC INSPECTION REPORT 50-315/02-02(DRP); 50-316/02-02(DRP)

Dear Mr. Bakken:

On March 31, 2002, the NRC completed an inspection at your D. C. Cook Nuclear Power Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on April 5, 2002, with you and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report discusses a finding that appears to have low to moderate safety significance. As described in Section 4OA1.1 of this report, your staff failed to take corrective action to preclude a repetitive failure of the Unit 2 Turbine Driven Auxiliary Feedwater Pump (TDAFWP), a significant condition adverse to quality. Specifically, the Unit 2 TDAFWP failed to start on August 10, 2001, due to the failure of the trip throttle valve latch mechanism to remain engaged during pump start. On December 13, 2001, your staff obtained information from the trip throttle valve vendor identifying critical parameters for the trip hook mechanism geometry and alignment. Your staff failed to promptly perform corrective actions to verify that the Unit 2 TDAFWP trip hook conformed to these critical parameters. Consequently, a second failure of the Unit 2 TDAFWP occurred on January 18, 2002, due to the failure of the trip throttle valve latch mechanism to remain engaged during pump start. Subsequent review determined that the root cause of the August 10, 2001 and January 18, 2002 failures was due to incorrect trip hook geometry and alignment.

The inadequate engagement of the Unit 2 TDAFWP throttle valve latch mechanism in August 2001 resulted in a calculated "T/2" fault exposure time of 42 days. The additional failure of the Unit 2 TDAFWP in January 2002 represented an additional 38 days of "T/2" fault exposure. Because both of the TDAFWP failures were related, the NRC evaluated the identified performance deficiencies, including procedure and corrective action weaknesses, as a single problem identification and resolution issue. This finding was assessed using the applicable Significance Determination Process as a potentially safety significant finding that was preliminarily determined to be White, a finding with some increased importance to safety, which may require additional NRC inspection. The finding has a low to moderate safety significance because the resultant 80 day fault exposure time represented an actual loss of safety function for a single train of auxiliary feedwater for greater than its Technical Specification allowed outage time and the train would have been unavailable if called upon for actual mitigation purposes.

The finding also appears to be an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600. The current Enforcement Policy is included on the NRC's website at http://www.nrc.gov.

Before the NRC makes a final decision on this matter, we are providing you an opportunity to request a Regulatory Conference where you would be able to provide your perspectives on the significance of the finding, the bases for your position, and whether you agree with the apparent violation. If you choose to request a Regulatory Conference, we encourage you to submit your evaluation and any differences with the NRC evaluation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. The NRC will also issue a press release to announce the Regulatory Conference.

Please contact Mr. Anton Vegel at (630) 829-9620 within 10 business days of the date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of apparent violations described in the enclosed inspection report may change as a result of further NRC review.

Based on the results of this inspection, one additional finding of very low safety significance (Green) was identified (See Section 1R22). This issue was determined to be a violation of NRC requirements. However, because of the very low safety significance and because it has been entered into your corrective action program, the NRC is treating the issue as a Non-Cited Violation, in accordance with Section VI.A.1 of the NRC Enforcement Policy. If you contest the Non-Cited Violation, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-001; and the NRC Resident Inspector at the D. C. Cook facility.

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

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

/RA/

Geoffrey E. Grant, Director
Division of Reactor Projects

Docket Nos. 50-315; 50-316
License Nos. DPR-58; DPR-74

Enclosure: Inspection Report 50-315/02-02(DRP);
50-316/02-02(DRP)

cc w/encl: J. Pollock, Site Vice President
M. Finissi, Plant Manager
M. Rencheck, Vice President
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R. Whale, Michigan Public Service Commission
Michigan Department of Environmental Quality
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MI Department of State Police
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REGION III

Docket Nos:	50-315; 50-316
License Nos:	DPR-58; DPR-74
Report No:	50-315/02-02(DRP); 50-316/02-02(DRP)
Licensee:	American Electric Power Company
Facility:	D. C. Cook Nuclear Power Plant, Units 1 and 2
Location:	1 Cook Place Bridgman, MI 49106
Dates:	February 10 through March 31, 2002
Inspectors:	B. Kemker, Senior Resident Inspector K. Coyne, Resident Inspector J. Maynen, Resident Inspector H. Peterson, Senior Engineer (Lead Inspector) D. McNeil, Senior Engineer W. Slawinski, Senior Radiation Specialist
Approved by:	A. Vegel, Chief Branch 6 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000315-02-02(DRP), IR 05000316-02-02(DRP), on 02/09 - 03/31/2002, Indiana Michigan Power Company, D. C. Cook Nuclear Power Plant, Units 1 and 2. Post Maintenance Testing, Surveillance Testing, Performance Indicator Verification.

The baseline inspection was conducted by resident and region based inspectors. The inspectors identified one Preliminary White finding, which was an apparent violation and one Green finding. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html. Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violations.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

- TBD. The inspectors identified an Apparent Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," associated with the licensee's failure to perform adequate maintenance and testing on valve 2-CS-369 (reactor coolant pump seal water heat exchanger to volume control tank (VCT) shutoff valve). This issue was self-revealed on February 16, 2002, when the Unit 2 west centrifugal charging pump (CCP) exhibited indications of gas binding following swap over of the suction source from the VCT to the refueling water storage tank (RWST).

  The inspectors assessed this finding using the Significance Determination Process. The inspectors concluded that this issue had a credible impact on safety and was therefore more than a minor concern. In particular, the gas intrusion into the suction of the running Unit 2 west CCP while aligned to the RWST impacted the capability of the high head injection system to provide the inventory and reactivity control safety functions. Additionally, the inspectors concluded that gas intrusion affecting the west CCP could have reasonably affected the operability and availability of the redundant Unit 2 east CCP. The inspectors concluded that this issue degraded the licensee's ability to add inventory to the reactor coolant system with the unit shutdown. The risk significance of this issue will be determined following completion of a Phase 2 analysis for shutdown risk. The safety significance of this issue is to be determined (TBD) pending the completion of additional staff review. (Section 1R19)

- Green. A Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control," was identified for the licensee's failure to utilize valid acceptance criteria for stroke time testing the Unit 2 pressurizer power operated relief valves (PORVs). Specifically, the licensee failed to assure that the correct acceptance criteria contained in the applicable design document were incorporated into the surveillance test procedure used for testing the PORVs.

The inspectors assessed this finding using the Significance Determination Process (SDP). The inspectors determined that this issue could become a more significant safety concern if left uncorrected and was therefore more than a minor concern. Specifically, the failure to adequately perform surveillance testing with valid acceptance criteria could reasonably result in the failure to identify degraded or inoperable safety related components. The inspectors also concluded that this issue could credibly affect the operability of the pressurizer PORVs, which are mitigating system components under the SDP. The inspectors determined that, because the as-found stroke times were found within the correct acceptance criteria, this issue was of very low safety significance. (Section 1R22)

- Preliminary White. An Apparent Violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," was identified for the licensee's failure to take prompt corrective actions to prevent a repetitive failure of the Unit 2 turbine driven auxiliary feedwater pump (TDAFWP). Specifically, the Unit 2 TDAFWP failed to start on August 10, 2001, due to the failure of the trip throttle valve latch mechanism to remain engaged during pump start. On December 13, 2001, the licensee obtained information from the trip throttle valve vendor identifying critical parameters for the trip hook mechanism geometry and alignment and failed to promptly perform corrective actions to verify that the Unit 2 TDAFWP trip hook conformed to these critical parameters. Consequently, a second failure of the Unit 2 TDAFWP occurred on January 18, 2002, due to the failure of the trip throttle valve latch mechanism to remain engaged during pump start.

  The inspectors and Region III Senior Reactor Analysts assessed this finding using the Significance Determination Process (SDP). A Phase 3 SDP analysis was performed using insights from the licensee's updated Probabilistic Risk Assessment model. Based on the results of the Phase 3 SDP analysis, the NRC staff determined that this finding has a low to moderate safety significance because the resultant 80 day fault exposure time represented an actual loss of safety function for a single train of auxiliary feedwater for greater than its Technical Specification allowed outage time and the train would have been unavailable if called upon for actual mitigation purposes. (Section 4OA1)

B. Licensee Identified Violations

No violations of significance were identified.

Report Details

Summary of Plant Status:

Unit 1 operated at or near full power for the duration of the inspection period.

Unit 2 was defueled at the beginning of the inspection period for refueling outage U2C13. Following completion of the refueling outage, the licensee synchronized the unit to the grid on February 28, 2002 and raised power to approximately 30 percent. The licensee subsequently reduced power that same day to approximately 2 percent to perform an emergent repair to a steam generator main steam isolation valve. Following repair to the valve, the licensee synchronized the unit to the grid on March 1, 2002. The unit operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

Mitigating Systems Cornerstone

- Unit 1 Turbine Driven Auxiliary Feedwater (N Train)
- Unit 1 West Component Cooling Water Train

The inspectors selected these systems based on their risk significance relative to the mitigating systems cornerstone. The inspectors reviewed operating procedures, Technical Specification (TS) requirements, Administrative Technical Requirements (ATRs), system diagrams, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing its intended functions.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Walkdowns

a. Inspection Scope

The inspectors performed fire protection walkdowns of the following four risk-significant plant areas:

Mitigating Systems Cornerstone

- Unit 1 Main Steam Valve Enclosure (Zone 33)
- Unit 1 Switchgear Room Cable Vault (Zone 55)
- Unit 1 Auxiliary Cable Vault (Zone 56)
- Unit 1 Refueling Water Storage Tank Pipe Tunnel (Zone 116)

The inspectors verified that fire zone conditions were consistent with assumptions in the licensee's fire hazard analysis. The inspectors walked down fire detection and suppression equipment, assessed the material condition of fire control equipment, and evaluated the control of transient combustible materials.

b. Findings

No findings of significance were identified.

.2 Temporary Instruction 2515/146, Hydrogen Storage Locations

a. Inspection Scope

The inspectors walked down the licensee's bulk hydrogen storage locations to verify that the licensee was complying with applicable codes and to ensure that unrecognized conditions do not exist. Additionally, the inspectors reviewed documents and discussed hydrogen storage locations with engineering personnel.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Facility Operating History

a. Inspection Scope

The inspectors reviewed the plant's operating history from January 2001 through January 2002, to assess whether the Licensed Operator Requalification Training (LORT) program had addressed operator performance deficiencies noted at the plant.

b. Findings

No findings of significance were identified.

.2 Licensee Requalification Examinations

a. Inspection Scope

The inspectors performed a biennial inspection of the licensee's LORT program. The inspectors reviewed the annual requalification operating and written examination material to evaluate general quality, construction, and difficulty level. The operating portion of the examination was inspected during March 27-28, 2002. The operating examination material consisted of two dynamic simulator scenarios and five job performance measures (JPMs). The biennial written examination was administered on March 28, 2002. The biennial written examination consisted of 37 open reference multiple choice questions. The inspectors reviewed the methodology for developing the examinations, including the LORT program two year sample plan, probabilistic risk assessment (PRA) insights, level of difficulty, and previously identified operator performance deficiencies. The inspectors assessed the level of examination material duplication during the current year annual examinations and with last year's annual examinations. The inspectors also interviewed members of the licensee's management, and training staff and discussed various aspects of the examination development.

b. Findings

No findings of significance were identified.

.3 Licensee Administration of Requalification Examinations

a. Inspection Scope

The inspectors observed the administration of the requalification operating test to assess the licensee's effectiveness in conducting the test and to assess the facility evaluators' ability to determine adequate performance using objective, measurable performance standards. The inspectors evaluated the performance of 12 licensed operators for one operating shift crew during two dynamic simulator scenarios in parallel with the facility evaluators. The operating shift was divided into three simulator shift crews for evaluation purposes. Each evaluation crew consisted of two Senior Reactor Operators, two Reactor Operators, and a Shift Technical Advisor. In addition, the inspectors observed licensee evaluators administering five JPMs on a select number of operators. The inspectors observed the training staff personnel administering the operating test, including pre-examination briefings, observations of operator performance, individual and crew evaluations after dynamic scenarios, techniques for JPM cuing, and the final evaluation briefing. The inspectors noted the performance of the simulator to support the examinations. The inspectors also reviewed the licensee's overall examination security program.

b. Findings

No findings of significance were identified.

.4 Licensee Training Feedback System

a. Inspection Scope

The inspectors assessed the methods and effectiveness of the licensee's processes for revising and maintaining its LORT program up to date, including the use of feedback from plant events and industry experience information. The inspectors interviewed licensee personnel (operators, instructors, training management, and management) and reviewed the applicable licensee's procedures. In addition, the inspectors reviewed the licensee's quality assurance/quality control oversight activities, including licensee's training and department self-assessment reports, to evaluate the licensee's ability to assess the effectiveness of its LORT program and to implement appropriate corrective actions.

b. Findings

No findings of significance were identified.

.5 Licensee Remedial Training Program

a. Inspection Scope

The inspectors assessed the adequacy and effectiveness of the remedial training conducted since the previous annual requalification examinations and the training planned for the current examination cycle to ensure that they addressed weaknesses in licensed operator or crew performance identified during training and plant operations. The inspectors reviewed remedial training procedures and individual remedial training plans, and interviewed licensee personnel (operators, instructors, and training management). In addition, the inspectors reviewed the licensee's current examination cycle remediation packages for unsatisfactory operator performance on the written examination and operating test to ensure that remediation and subsequent re-evaluations were completed prior to returning individuals to licensed duties.

b. Findings

No findings of significance were identified.

.6 Conformance with Operator License Conditions

a. Inspection Scope

The inspectors evaluated the facility and individual operator licensees' conformance with the requirements of 10 CFR Part 55. The inspectors reviewed the facility licensee's program for maintaining active operator licenses and to assess compliance with 10 CFR 55.53(e) and (f). The inspectors reviewed the procedural guidance and the process for tracking on-shift hours for licensed operators and which control room positions were granted credit for maintaining active operator licenses. The inspectors also reviewed eight licensed operators' medical records maintained by the facility's contracted medical staff for ensuring the medical fitness of its licensed operators and to assess compliance with medical standards delineated in ANSI/ANS-3.4 and with 10 CFR 55.21 and 10 CFR 55.25. In addition, the inspectors reviewed the licensee's LORT program to assess compliance with the requalification program requirements as described by 10 CFR 55.59(c).

b. Findings

No findings of significance were identified.

.7 Written Examination and Operating Test Results

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of individual written tests, JPM operating tests, and simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee during calender year 2002.

b. Findings

No findings of significance were identified.

.8 Resident Inspector Quarterly Review

a. Inspection Scope

The inspectors assessed licensed operator performance and the training evaluators' critique during a licensed operator annual requalification evaluation in the D. C. Cook Plant operations training simulator on March 6, 2002. The inspectors focused on alarm response, command and control of crew activities, communication practices, procedural adherence, and implementation of emergency plan requirements.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

The inspectors evaluated the licensee's implementation of 10 CFR 50.65 (the Maintenance Rule). The inspectors assessed: (1) functional scoping in accordance with the Maintenance Rule, (2) characterization of system functional failures, (3) safety significance classification, (4) 10 CFR 50.65 (a)(1) or (a)(2) classification for system functions, and (5) performance criteria for systems classified as (a)(2) or goals and corrective actions for systems classified as (a)(1). The inspectors reviewed the following risk-significant systems and components:

Initiating Events Cornerstone

- Circulating Water System

Barrier Integrity Cornerstone

- Hydrogen Ignitor System

Mitigating Systems Cornerstone

- Compressed Air System
- Component Cooling Water System

In addition, the inspectors reviewed the issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance. The inspectors also reviewed the licensee's corrective actions for Maintenance Rule related issues that were documented in selected condition reports (CRs).

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for maintenance activities on the following equipment:

Mitigating Systems Cornerstone

- Unit 1 East Essential Service Water (ESW) Pump Replacement
- Unit 2 East Centrifugal Charging Pump (CCP) Oil Change and Relay Calibration
- Unit 2 West Component Cooling Water Pump Oil Change
- Unit 1 CD Diesel Generator Outage Maintenance Work Window

These activities were selected based on their potential risk significance relative to the mitigating systems cornerstone. As applicable for each of the above activities, the inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified that plant conditions were consistent with the risk assessment. The inspectors also reviewed TS and ATR requirements and walked down portions of redundant safety systems, when applicable, to verify that risk analysis assumptions were valid and applicable requirements were met.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following CRs to ensure that either: (1) the condition did not render the involved equipment inoperable or result in an unrecognized increase in plant risk, or (2) the licensee appropriately applied TS limitations and appropriately returned the affected equipment to an operable status.

Mitigating Systems Cornerstone

- CR 02047050, "Unit 2 West CCP Showed Signs of Air Entrainment"
- CR 02050022, "Control Switch 1-101-NRV-152 May Not Be in the Automatic Position Fully"
- CR 02057005, "Inability to Test 112 Percent Main Turbine Overspeed Trip Device"

The inspectors also reviewed the licensee's justification for not correcting existing degraded and nonconforming conditions during refueling outage U2C13 consistent with the timeliness guidance contained in Generic Letter 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," Revision 1.

In addition, the inspectors reviewed the issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance. The inspectors also reviewed the licensee's corrective actions for issues potentially affecting the operability of structures, systems, and components that were documented in selected CRs.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed the engineering analyses, modification documents and design change information associated with the following permanent plant modification:

Barrier Integrity Cornerstone

- Design Change 2-DCP-4821, "Install New Impellers In the Containment Spray Pumps (2-PP-9E & W)"

The inspectors verified the design adequacy of the modification and focused the inspection activities on the following parameters associated with the design change: heat removal, equipment protection, operations, flowpaths, process media, licensing basis, and failure modes.

Completed activities associated with the implementation of the modification were also inspected and the inspectors discussed the modification with the responsible engineers and operations staff. In addition, the inspectors reviewed the applicable sections of the TS, Updated Final Safety Analysis Report (UFSAR), and CRs associated with the design change packages and the installation of the modification.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the post maintenance testing requirements associated with the following scheduled maintenance activities:

Mitigating Systems Cornerstone

- Job Order (JO) 01094018, "Replace Diaphragm in Reactor Coolant Seal Return to Volume Control Tank Isolation Valve 2-CS-369"
- JO 01262081, "Rebuild the Unit 1 East ESW Pump 1-PP-7E"
- JO 020309004, "Troubleshoot and Repair 2-OME-150-CD, Unit 2 CD Diesel Generator"
- JO 02049054, "Troubleshoot and Repair 600 Volt Supply Breaker to the Unit 2 CD2 Battery Charger That Tripped Twice"

The inspectors reviewed test methodology and acceptance criteria to assess the appropriateness of assigned post maintenance testing for the scope of work performed. Documented test data was reviewed to verify that the testing was complete and that the equipment was able to perform the intended safety functions.

In addition, the inspectors reviewed the issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance. The inspectors also reviewed the licensee's corrective actions for post maintenance testing related issues that were documented in selected CRs.

b. Findings

b.1 Failure to Perform Adequate Maintenance and Testing on Valve 2-CS-369 Resulted in Gas Binding the Unit 2 West CCP

The inspectors identified an Apparent Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," associated with the licensee's failure to perform adequate maintenance and testing on valve 2-CS-369 (reactor coolant pump seal water heat exchanger to volume control tank (VCT) shutoff valve). This issue was self-revealed on February 16, 2002, when the Unit 2 west CCP exhibited indications of gas binding following swap over of the suction source from the VCT to the refueling water storage tank (RWST). Pending additional evaluation, the safety significance of this issue is "To Be Determined" (TBD).

Description

On February 16, 2002, while performing a vacuum refill of the reactor coolant system (RCS), control room operators aligned the RWST as the CCP suction source and isolated the VCT. Following isolation of the VCT, the Unit 2 west CCP exhibited indications of gas binding, including a drop in pump motor amperage and a reduction of charging system flow to near 0 gallons per minute (gpm). After operators unisolated the VCT, the CCP amperage and flow recovered to normal values. Operators then made a second attempt to swap the CCP suction source from the VCT to the RWST; but again, the gas binding symptoms returned when the VCT was isolated. Based on the unexpected system response, the licensee declared the Unit 2 RWST boration flowpath inoperable and initiated CR 02047050.

The licensee determined that the cause of this event was the failure to have 2-CS-369 fully closed, which, due to the pressure difference between the VCT and the RWST, allowed gas to vent from the top of the VCT directly to the CCP suction line. The reactor coolant pump seal return flow can be directed either to the CCP suction via 2-CS-370 or directly to the VCT via 2-CS-369. During normal operation, 2-CS-369 is sealed closed to prevent VCT cover gas intrusion directly to the CCP suction. On February 1, 2002, the licensee performed preventative maintenance to replace the 2-CS-369 valve diaphragm under JO 01094018. Because the valve was completely disassembled to replace the diaphragm, JO 01094018 included instructions for valve stem stop nut adjustment to ensure that the valve stroke would be correct. Proper adjustment of the stem stop nut allows full closure of the diaphragm valve without excessive crushing force on the valve diaphragm. The licensee later identified that the stem stop nut was incorrectly adjusted, which prevented full closure of the valve.

The inspectors reviewed the maintenance work instructions for the 2-CS-369 diaphragm replacement and determined that the work instructions were not correctly implemented. Specifically, maintenance personnel failed to adequately perform the instructions for valve stop nut adjustment contained in procedure 12 MHP 5021.001.023, "Manual Diaphragm Valve Maintenance," Revision 6. Steps 6.6.3, 6.6.4, and 6.6.5 of 12 MHP 5021.001.023 required that the stem stop nut be locked in position by tightening the stem lock nut after the valve was turned clockwise 1/8 of a turn beyond the closed seat contact point. The purpose of these steps was to ensure that the position of the stop nut would allow full closure of 2-CS-369. On February 16, 2002, the licensee identified that the stem lock nut was loose and that the position of the stop nut prevented full closure of 2-CS-369. The licensee performed several corrective actions for this condition, including: (1) adjustment of the stop nut and closing of 2-CS-369; (2) venting of the safety injection (SI) pump and CCP suction headers; and, (3) testing of the Unit 2 west CCP in accordance with procedure 02 OHP 4030.STP.052W, "West Centrifugal Charging Pump Operability Test." The licensee subsequently declared the RWST boration flowpath operable on February 17, 2002.

In addition, the inspectors determined that the post maintenance testing performed following diaphragm replacement was not adequate to identify the potential mis-positioning of the stem stop nut. The post maintenance testing requirements in JO 01094018 specified only an external leakage inspection. The inspectors noted that although full closure of 2-CS-369 was required to prevent gas intrusion into the suction of the CCPs, no testing was performed on 2-CS-369 immediately following diaphragm replacement to verify valve seat leak tightness. The inspectors determined that the failure to correctly implement maintenance instructions for valve stem stop nut adjustment and the failure to perform an adequate post maintenance test constituted a violation of NRC requirements.

<u>Analysis</u>

The inspectors assessed this issue using the Significance Determination Process (SDP). The inspectors concluded that this issue had a credible impact on safety and was therefore more than a minor concern. In particular, the gas intrusion into the suction of the running Unit 2 west CCP while aligned to the RWST impacted the capability of the high head injection system to provide inventory and reactivity control safety functions. Additionally, the inspectors concluded that gas intrusion affecting the west CCP could have reasonably affected the operability and availability of the redundant Unit 2 east CCP. Consequently, the inspectors determined that this issue was associated with the mitigating systems cornerstone. The inspectors concluded that 2-CS-369 was degraded when the diaphragm was replaced (February 1, 2002) until completion of the corrective action to adjust the valve stem stop nut (February 16, 2002). Therefore, the inspectors concluded that this issue should be reviewed using the guidance provided in Inspection Manual Chapter (IMC) 0609, Appendix G, "Shutdown Operations Significance Determination Process." The inspectors considered the following during the initial risk assessment:

- The 2-CS-369 diaphragm was replaced on February 1, 2002 with Unit 2 defueled. Unit 2 entered Mode 6 (Refueling) on February 10, 2002 and completed core reload on February 12, 2002. Because the degraded condition of 2-CS-369 was identified and corrected on February 16, 2002, the safety function provided by the CCPs was degraded for approximately 6 days with fuel in the reactor vessel.

- Based on the observed Unit 2 west CCP performance during the gas intrusion event on February 16, 2002 (decreased pump amperage and near 0 gpm flowrate), the inspectors concluded that the degraded condition of 2-CS-369 would render the CCPs unavailable when aligned to the RWST.

- The licensee determined that both SI pumps were available during the period, except for 2-1/2 hours on February 12, 2002. During the time that the SI pumps were unavailable, the unit was in Mode 6 with refueling cavity level greater than 23 feet above the active fuel level.

- To support low temperature over-pressure protection (LTOP) requirements, the breakers for both SI pumps were racked out. The licensee estimated that approximately 30 minutes would be required to restore an SI pump to service. Use of the SI pumps to restore RCS inventory during a loss of inventory was addressed in abnormal procedure 02 OHP 4022.017.001, "Loss of RHR [Residual Heat Removal] Cooling."

- The inspectors determined that gas intrusion into the suction of the CCPs would not be expected to cause a similar failure for the SI pumps. Although the SI pumps share a common suction with the CCPs from the RWST, check valve 2-SI-185 would prevent migration of gas to the suction of the SI pumps. The licensee seat leak tested 2-SI-185 on February 8, 2002 and measured a seat leakage rate of 0 gpm.

- Based on a review of the Unit 2 shutdown risk status sheets during the period of February 15 and 16, 2002, the inspectors determined that the minimum time to boil upon a loss of core cooling was 13 minutes. The time to boil with the reactor coolant not in a reduced inventory condition was estimated to be approximately 2 hours.

- The licensee entered a mid-loop reduced inventory condition on February 15, 2002 to support vacuum refill of the RCS. The licensee exited the mid-loop condition on February 16, 2002. The inspectors estimated that the unit was in reduced inventory condition for approximately 23 hours.

- Because the reactor coolant had not been fully refilled prior to the event, the steam generators were unavailable for core cooling.

- The remote unit has the capability to provide high head injection via unit cross-tie valves. Although procedure 02 OHP 4025.001.001, "Emergency Remote Shutdown," addresses use of the charging system cross-tie during certain Appendix R fire protection events, it did not include specific instructions for inventory control during loss of shutdown cooling events.

Based on the above information, the inspectors concluded that the most appropriate IMC 0609, Appendix G checklist to use for this issue was the checklist for "Pressurized Water Reactor Cold Shutdown and Refueling Operation - Reactor Coolant System Closed and No Inventory in Pressurizer, Time to boiling less than 2 hours." Because of the unavailability of the high pressure injection CCPs due to the degraded condition of 2-CS-369, the inspectors concluded that the minimum equipment specified in Section II.C were not met from February 14, 2002 (when the unit entered Mode 5) to February 16, 2002 (when the licensee identified and corrected the degraded condition of 2-CS-369). Consequently, the inspectors concluded that this issue degraded the licensee’s ability to add inventory to the RCS and therefore required a Phase 2 analysis.

The risk significance of this issue will be determined following completion of a Phase 2 analysis for shutdown risk. The inspectors discussed the safety significance of this issue with the Regional Senior Reactor Analysts (SRAs), and, pending the completion of additional evaluation, the safety significance of this issue is to be determined (TBD).

Enforcement

10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, the licensee failed to (1) correctly accomplish the instructions provided in 12 MHP 5021.001.023, Section 6.6, for valve stroke adjustment of 2-CS-369, an activity affecting quality, and (2) provide appropriate acceptance criteria to ensure that valve stop nut adjustment was satisfactorily accomplished. Specifically, steps 6.6.3, 6.6.4, and 6.6.5, which were performed on February 1, 2002, required that the handwheel for 2-CS-369 be turned clockwise 1/8 of a turn beyond the point where the valve made closed seat contact, and the stem stop nut be turned clockwise until it made contact with the handwheel and then locked in position by tightening the stem lock nut. On February 16, 2002, the licensee identified that the stem stop nut was not locked and its position prevented full closure of 2-CS-369, which allowed VCT cover gas to flow to the CCP suction header. In addition, the instructions provided in JO 01094018 did not include appropriate acceptance criteria to ensure that 2-CS-369 valve stroke adjustment had been satisfactorily accomplished after valve maintenance. Consequently, on February 16, 2002, the Unit 2 west CCP became gas bound following alignment of the pump suction to the RWST. This issue is considered to be an Unresolved Item pending a final safety significance determination (URI 50-316-02-02-01(DRP)).

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors continued their evaluation of the licensee’s conduct of Unit 2 refueling outage activities during this inspection period to assess the licensee’s control of plant configuration and management of shutdown risk. The inspectors reviewed configuration management to verify that the licensee maintained defense-in-depth commensurate with the shutdown risk plan and reviewed major outage work activities to ensure that correct system lineups were maintained for key mitigating systems. Other major outage activities evaluated included the licensee’s control of the following:

- Containment penetrations in accordance with the TS
- Systems, structures, and components (SSCs) which could cause unexpected reactivity changes
- Flow paths, configurations, and alternate means for RCS inventory addition and control of SSCs which could cause a loss of inventory
- RCS pressure, level, and temperature instrumentation

- Switchyard activities and the configuration of electrical power systems in accordance with the TS and shutdown risk plan
- SSCs required for decay heat removal

The inspectors also observed portions of the restart activities to verify that requirements of the TS and administrative procedure requirements were met prior to changing operational modes or plant configurations. Major restart inspection activities performed included:

- Verification that RCS boundary leakage requirements were met prior to entry into Mode 4 (Cold Shutdown) and subsequent operational mode changes
- Verification that containment integrity was established prior to entry into Mode 4
- Inspection of the Containment Building to assess material condition and search for loose debris, which if present could be transported to the containment recirculation sumps and cause restriction of flow to the emergency core cooling system (ECCS) pump suctions during loss-of-coolant accident conditions
- Verification that the material condition of the Containment Building ECCS recirculation sumps met the requirements of the TS and was consistent with the design basis
- Observation and review of reactor physics testing to verify that core operating limit parameters were consistent with the core design so that the fuel cladding barrier would not be challenged

The inspectors interviewed operations, engineering, work control, radiological protection, and maintenance department personnel and reviewed selected procedures and documents.

In addition, the inspectors reviewed the issues that the licensee entered into the corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance. The inspectors also reviewed the licensee's corrective actions for refueling outage issues documented in selected CRs.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

For the surveillance test procedures listed below, the inspectors observed selected portions of the surveillance tests and reviewed the test results to determine whether risk significant systems and equipment were capable of performing their intended safety functions and to verify that testing was conducted in accordance with applicable procedural and TS requirements:

Barrier Integrity Cornerstone

- 02 OHP 4030.STP.007E, "East Containment Spray System Operability Test"

Mitigating Systems Cornerstone

- 02-OHP-4030-202-060, "Pressurizer Relief Valve Testing"
- 02-OHP 4030.001.002, "Containment Inspection Tours"
- 02-OHP-4030-232-217A, "DG2CD Load Sequencing & ESF Testing"

The inspectors reviewed the test methodology and test results in order to verify that equipment performance was consistent with safety analysis and design basis assumptions. The inspectors also reviewed CRs concerning surveillance testing activities to verify that identified problems were appropriately characterized.

b. Findings

b.1 Failure to Use Valid Acceptance Criteria for Stroke Time Testing the Unit 2 Pressurizer Power Operated Relief Valves (PORVs)

The inspectors identified a finding of very low safety significance (Green) associated with the licensee's failure to utilize valid acceptance criteria for stroke time testing the Unit 2 pressurizer PORVs. This finding was dispositioned as a Non-Cited Violation of 10 CFR 50, Appendix B, Criteria XI, "Test Control."

Description

The inspectors examined the results of stroke time testing of the Unit 2 pressurizer PORVs (2-NRV-152 and 2-NRV-153), which was performed on February 12, 2002 to obtain new in-service testing baseline stroke time values for the valves following maintenance and to demonstrate operability of the valves for LTOP prior Unit 2 entering Mode 5 (Cold Shutdown) upon completion of refueling activities. The two air-operated valves are provided with backup air supply bottles that are designed to provide sufficient air to cycle the PORVs for 10 minutes without operator action during an LTOP event. The minimum backup air supply bottle pressure (900 pound per square inch) and the minimum valve stroke cycle (open and closed) are therefore critical parameters. The licensee had previously had difficulty meeting the minimum stroke time acceptance criteria when testing the valves at the beginning of the Unit 2 refueling outage and revised the acceptance criteria based on its review of the original design calculation for sizing the backup air supply bottles. The inspectors compared the acceptance criteria in the completed surveillance test procedure (02-OHP-4030-202-060, "Pressurizer Relief Valve Testing," Revision 0, Change 0) with the approved acceptance criteria in Design Information Transmittal (DIT)-B-02327 and noted that the licensee had failed to correctly use the revised acceptance criteria. Specifically, DIT-B-02327 determined the following minimum valve stroke time requirements for both 2-NRV-152 and 2-NRV-153:

Open	Closed
2.39 seconds minimum	1.33 seconds minimum

or

Open	Closed	Open + Closed
2.0 seconds minimum	1.0 second minimum	3.72 seconds minimum

The second set of minimum stroke time values were provided in DIT-B-02327 as an alternative set of acceptance criteria with the stipulation that the sum of the minimum open and closed times be equal to or greater than 3.72 seconds. Based on the sizing calculation, the PORVs would not be considered operable if the sum of the minimum open and closed times was less than 3.72 seconds.

The acceptance criteria used in 02-OHP-4030-202-060 for 2-NRV-152 was:

Open	Closed
2.8 seconds minimum	1.0 second minimum

The acceptance criteria used in 02-OHP-4030-202-060 for 2-NRV-153 was:

Open	Closed
2.6 seconds minimum	1.0 second minimum

The inspectors first noted that the acceptance criteria used in the surveillance test procedure for both valves did not match the acceptance criteria specified in DIT-B-02327. This could be considered acceptable provided the sum of the minimum open and closed acceptance criteria values for each valve is less than 3.72 seconds. The inspectors then identified that although the sum of the minimum open and closed acceptance criteria values used in the surveillance test procedure for 2-NRV-152 (3.8 seconds) was greater than 3.72 seconds, the sum of the minimum open and closed acceptance criteria values for 2-NRV-153 (3.6 seconds) was less than 3.72 seconds. It was therefore possible to meet the acceptance criteria used in the surveillance test procedure for 2-NRV-153 with unacceptable test results and to consider an inoperable valve to be operable. The inspectors compared the as-found stroke times for the two valves with the correct acceptance criteria from DIT-B-02327 and concluded that the valves were operable.

Analysis

The inspectors assessed the licensee's failure to utilize valid acceptance criteria for testing the Unit 2 pressurizer PORVs using the SDP. The inspectors determined that this issue could become a more significant safety concern if left uncorrected and was therefore more than a minor concern. The inspectors reviewed the licensee's corrective action program database and were concerned that there were several additional examples captured in the licensee's corrective action program, wherein incorrect acceptance criteria had been utilized for testing. Specifically, the failure to adequately perform surveillance testing with valid acceptance criteria could reasonably result in the failure to identify degraded or inoperable safety related components. The inspectors also concluded that this issue could credibly affect the operability of the pressurizer PORVs, which are mitigating system components under the SDP. The inspectors determined that, because the as-found stroke times were found within the correct acceptance criteria, this issue was of very low safety significance (Green).

Enforcement

10 CFR Part 50, Appendix B, Criterion XI, "Test Control," requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. Contrary to the above, the licensee failed to assure that 02-OHP-4030-202-060, "Pressurizer Relief Valve Testing," Revision 0, Change 0, incorporated the requirements and acceptance criteria contained in the applicable design document (i.e., Design Information Transmittal B-02327, "Stroke Time Acceptance Criteria for ½-NRV-152, 153," February 1, 2002). This is considered to be a violation of 10 CFR Part 50, Appendix B, Criterion XI. Because of the very low safety significance, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-316-02-02-02(DRP)). This violation is in the licensee's corrective action program as CR 02046050.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the temporary modification listed below to verify that the installation was consistent with design modification documents and that the modification did not adversely impact system operability or availability:

- 2-TM-00-54-R1 Installation of Noise Filtering Resistors on Cables 2-4450PB-2 for 2-ILA-111 and 2-5658PB-2 for 2-ILA-121

The temporary modification installed a 1000 ohm resistor between the shield and ground on each cable to alleviate unstable indication and spurious alarms for two SI system accumulator level channels. The inspectors verified that configuration control of the modification was correct by reviewing design modification documents and confirmed that appropriate post-installation testing was accomplished. The inspectors reviewed the design modification documents and the 10 CFR 50.59 evaluation against the applicable portions of the UFSAR.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiological Boundary Verification

a. Inspection Scope

The inspector conducted walkdowns of selected radiologically controlled areas to verify the adequacy of radiological boundaries and postings. The inspector reviewed the administrative controls for access to radiologically significant areas, as specified in radiation protection (RP) procedures and in radiation work permits (RWPs), and the physical controls established over those areas walked-down were assessed through direct observation. Specifically, the inspector walked-down several radiologically significant work area boundaries (high and locked high radiation areas) in the Unit 1 and Unit 2 Auxiliary Building and in the Unit 2 Containment Building and performed confirmatory radiation measurements in the Auxiliary Building to verify that these areas and selected radiation areas were properly posted and controlled in accordance with 10 CFR Part 20 and the licensee's TS.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Is-Reasonably-Achievable (ALARA) Planning and Controls (71121.02)

.1 Radiation Dose Goals and Trending

a. Inspection Scope

The inspector reviewed the station's historical outage exposure data for the last several refueling outages to establish its prior performance relative to the industry. Job specific and cumulative exposure performance and exposure trends for the first 20-days of the approximate 40-day Unit 2 refueling outage (U2C13) were reviewed to assess the licensee's current dose performance compared to pre-outage exposure projections. The inspector also reviewed the licensee's dose forecasting practices for those radiologically significant jobs that were being performed during the outage to determine if adequate technical bases for outage dose estimates existed. Dose forecasting practices were also reviewed to determine if outage experiences, craft work group defined job scope, resource estimates, and industry operating experiences were used to establish reasonable estimates. Additionally, the inspector reviewed the effectiveness of the RP organization's exposure tracking for the outage to verify that the licensee could identify problems with its exposure performance and take actions to address identified deficiencies.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspector reviewed the licensee's procedures for ALARA planning and evaluated several U2C13 ALARA plans to verify consistency with the procedure and to assess their overall adequacy relative to both current licensee practices and industry standards. Specifically, the inspector selected the following outage jobs that were projected to accrue cumulative doses in excess of 3.5 rem and assessed the adequacy of the radiological controls and the work planning for each:

- Temporary Shielding
- Insulation Activities in Containment
- Scaffold Erection/Removal in Containment
- Steam Generator Manway & Diaphragm Activities
- Steam Generator Primary Work and Platform Activities
- Control Rod Drive Mechanism Inspections
- Reactor Head Control Rod Drive Mechanism Penetration Weld Inspections
- Modify/Replace Pressurizer Spray Line Temperature Sensors

The inspector reviewed the RWP and the ALARA plan developed for each job and assessed the radiological engineering controls and other dose mitigation information specified in these documents to verify that plans included appropriate controls to reduce dose. These documents were also reviewed to determine if job history files, licensee lessons learned, and industry operating experiences were adequately integrated into each work package. The inspector discussed ALARA planning with several RP staff to verify that adequate interface existed between contractors, station work groups, and the ALARA staff during job planning. Additionally, plans to improve ALARA planning through more detailed task analysis were discussed with RP management and ALARA staff.

a. Findings

No findings of significance were identified.

.3 Implementation of ALARA Controls and Radiological Oversight of Work

a. Inspection Scope

The inspector selected the following high exposure or high radiation area jobs conducted during the outage and reviewed the execution of the ALARA program:

- Install, Modify and Remove Scaffolds in Containment (RWP # 022136)
- Shielding Activities in Containment (RWP # 022119)
- Modify/Replace Pressurizer Spray Line Temperature Sensor (RWP # 022170)

The inspector discussed job performance with involved RP staff, and total effective dose equivalent (TEDE) ALARA evaluations completed for these and a variety of other outage work activities, including steam generator work, were assessed for technical adequacy. Work in progress reports and radiological survey data for these and other selected jobs, as applicable, were also reviewed to assess their adequacy and consistency with licensee procedures. The pre-job brief for a transfer canal dive to repair a valve was attended to verify that the work activity was adequately planned and that radiological control information was exchanged effectively. The inspector evaluated the licensee's radiological engineering controls utilized at selected work locations to determine if the controls were consistent with those specified in the ALARA plans. The inspector also observed and questioned both RP staff that provided job coverage for various outage activities and radiation workers (radworkers) involved in outage work to verify that they had adequate knowledge of radiological work conditions and ALARA controls. Additionally, the inspector reviewed measurements and calculations completed by the RP staff to assess worker dose from skin contaminations and intakes to determine if the methodology was technically sound and if the results were accurate.

b. <u>Findings</u>

No findings of significance were identified.

.4 <u>Verification of Exposure Estimates and Exposure Tracking Systems</u>

a. <u>Inspection Scope</u>

The inspector reviewed the methods and assumptions used by the ALARA group to develop U2C13 dose estimates and compared collective outage and individual job dose performance and trends during the first 2 weeks of the outage to assess dose performance and to determine the accuracy of pre-outage projections. The inspector reviewed job dose history files, dose reductions anticipated through ALARA initiatives, and task specific breakdown analyses employed for certain jobs to verify that they were appropriately used to forecast outage doses. In particular, the inspector reviewed containment scaffolding work, which was anticipated to expend greater than 25 rem of exposure and to exceed original dose projections by more than 50 percent, and discussed its dose performance with ALARA staff. The review was conducted to determine whether the licensee had identified those factors that contributed to additional dose and/or inaccurate dose estimates. The inspector also reviewed the licensee's process used to revise dose estimates and capture lessons learned to verify compliance with the licensee's ALARA procedure. As of February 7, 2002, the licensee had recorded a collective outage exposure of approximately 105 rem, compared to its original estimate of about 95 rem for that stage of the outage. Selected work in progress reports were examined to evaluate the licensee's ability to assess the effectiveness of a job, to execute its ALARA plan, and to institute changes in work plans, if warranted. The licensee's exposure tracking system was also reviewed to determine if the level of exposure tracking detail, exposure report timeliness, and report distribution were sufficient to support the control of outage exposures.

b. Findings

No findings of significance were identified.

.5 Source Term Reduction and Control

a. Inspection Scope

The inspector reviewed the licensee's source term reduction activities, focusing on recent initiatives including those taken for the outage such as flushing, installation of shielding and changes in plant operations during the Unit 2 cool-down process. The inspector also evaluated the licensee's water chemistry control program implemented during the Unit 2 shutdown and its impact on source term reduction to determine whether the program was implemented consistent with station procedure and industry practices. First time water chemistry initiatives, which included a revised de-lithiation initiative to achieve acidic conditions earlier during cool-down and a revised RCS degas process to maintain corrosion products in soluble form, were reviewed by the inspector. These initiatives were reviewed to verify that the licensee implemented adequate practices for corrosion and source term control. The licensee's overall source term reduction program was assessed to verify that other initiatives such as cobalt reduction through stellite control were being pursued and to determine if a viable, progressive source term control program was in place.

b. Findings

No findings of significance were identified.

.6 Identification and Resolution of Problems

a. Inspection Scope

The inspector reviewed the results of an RP self-assessment completed as part of an ALARA outage planning readiness review and CRs generated by the RP staff during the outage to evaluate the effectiveness of the RP organization's ability to identify and correct problems. The inspector also reviewed outage related Performance Assurance Department field observations, RP program related CRs generated by other station departments, and investigation reports related to outage RP issues to verify that the licensee adequately identified individual problems and trends, determined contributing causes and extent of condition, and developed appropriate corrective actions.

a. Findings

On January 28, 2002, the licensee identified that a contract worker failed to stop work and leave the radiologically controlled area (RCA) as instructed by a radiation protection technician (RPT). The worker was instructed to leave the area because the individual's dose approached the RWP administrative limit established at 200 mrem for the day. The worker was conducting accumulator check valve testing in the Unit 2 lower containment. The test utilized an acoustic monitoring device, and the individual was an expert in setup and data results analysis. The RPT initially instructed the individual to leave containment just prior to the start of the data acquisition portion of the test. When the worker did not comply with the instruction, the RPT informed an RP supervisor of the problem, returned to the job site minutes later and heard the worker's electronic dosimetry (ED) accumulated dose alarm. The RPT then instructed the worker to leave the area a second time. The worker again failed to comply with the RPT's instructions, but shortly thereafter completed the data acquisition portion of the test, confirmed that good data was obtained, and then vacated the area.

After learning of the incident, radiation protection supervision immediately suspended the worker's access to the RCA and documented the occurrence in CR 02029016. The worker was counseled and coached by the licensee and allowed to return to work about an hour later to complete the testing. After the work was complete, the individual did not reenter the RCA. The licensee investigated the incident and on January 29, 2002, released the individual from the site because the licensee concluded that the individual chose not to comply with RP procedures. According to the licensee's preliminary investigation, the worker failed to obey the RPTs instructions because the individual: (1) spent considerable time setting-up the test equipment and was about to start the test; (2) anticipated completing the data acquisition portion of the test in a short time without significant additional dose; and (3) was an expert in the testing operation which involved "critical path" work that the worker felt pressure to complete without further delay. According to the licensee's preliminary investigation, the individual was aware of the requirement to comply with RP instructions and to immediately leave the work area upon receiving an ED alarm but decided not to comply for the reasons specified above. On January 31, 2002, the D. C. Cook station newspaper included an article that summarized the incident and reminded workers to follow RP procedures.

The dose received by the worker for the day was 201 mrem, just above the 200 mrem administrative dose limit established on the RWP that governed the check valve test work. The inspector reviewed area survey information to assess the radiological safety significance of the incident and determined that a potential for an overexposure did not exist had the worker continued to remain in the area longer. Work area radiation levels ranged from about 20 to 250 mrem/hour, depending on the worker's location relative to the valve being tested. At the time of the incident, the worker was positioned near the test equipment which was set-up in a lower radiation field. The worker accumulated a dose of about 3 mrem from the time he was initially instructed by the RPT to leave the area and several minutes later when he complied. Based on inspector discussions with members of the RP staff and review of the licensee's preliminary investigation, the inspector concluded that the worker's actions appeared to be in violation of RP procedure PMP-6010-RPP-001, "General Radiation Worker Instructions." This incident is considered to be an URI pending further NRC review to determine potential enforcement actions (URI 50-316-02-02-03(DRS)).

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification (71151)

.1 Unit 2 Turbine Driven Auxiliary Feedwater Pump (TDAFWP) Fault Exposure

(Closed) URI 50-316-01-19-03: "Apparent Violation of 10 CFR 50, Appendix B, Criterion V for the Failure to Incorporate Adequate Quantitative Acceptance Criteria in TDAFWP Maintenance Instructions."

a. Inspection Scope

On August 10, 2001, the Unit 2 TDAFWP failed to start during three successive start attempts. The inspectors documented a preliminary evaluation of this issue in NRC Inspection Report 50-315/316-01-019(DRP), Section 4OA1.1. To support additional risk evaluation of the TDAFWP failure in accordance with the SDP, the inspectors identified this issue as URI 50-316-01-19-03. Prior to the completion of the NRC staff's risk significance evaluation for this issue, an additional failure of the Unit 2 TDAFWP occurred on January 18, 2002. The inspectors reviewed the circumstances of this subsequent TDAFWP failure to fully assess the adequacy of the licensee's previous apparent cause evaluation and to evaluate the risk significance of the repetitive failure.

b. Findings

The inspectors identified an Apparent Violation of low to moderate risk significance (White) associated with failure of the licensee to take appropriate corrective actions to prevent a repetitive failure of the Unit 2 TDAFWP.

Description

On January 18, 2002, the Unit 2 TDAFWP failed to start during performance of time response testing. The licensee determined that the failure was due to the unlatching of the TDAFWP trip throttle valve (2-QT-506). A similar TDAFWP failure occurred on August 10, 2001. Following the January 18, 2002 failure, the licensee declared the TDAFWP inoperable but reset the trip latch mechanism to align the TDAFWP for auto-start capability. Although no corrective maintenance was performed on the TDAFWP, the pump started satisfactorily on January 19, 2002 following a pre-planned reactor trip to support the Cycle 13 refueling outage.

Following the January 18, 2002 TDAFWP failure, the licensee initiated CR 02018064 and performed a root cause evaluation to determine the cause of the repetitive pump failures. The licensee concluded that incorrect machining of the trip throttle valve trip hook, resulting in inadequate alignment of the trip hook and latching up lever faces, was the root cause of the repetitive failure. In order to open the trip throttle valve, the trip hook engages the latching up lever to permit admission of steam to the turbine. During a turbine trip, the trip hook would rotate on the trip hook pin and release the latching up lever to close the trip throttle valve. Incorrect machining of the trip hook resulted in a rotational force on the trip hook that would cause the latching mechanism to disengage.

A contributing cause to the pump failure was an the incorrect alignment specification for engagement between the trip hook and latching up lever previously discussed in NRC Inspection Report 50-315/316-01-19(DRP). Proper machining of the trip hook would result in a parallel alignment of the trip hook face and the latching up lever face (this would allow adequate surface area engagement to prevent inadvertent unlatching of the trip throttle valve).

Following the January 18, 2002 pump failure, the licensee performed a visual inspection of the trip throttle valve and determined that the faces of the trip hook and latching up lever were not in parallel alignment, a condition which would cause the trip hook to disengage the latching up lever under load. The licensee determined that the latch face of the trip hook had been machined at an incorrect angle, resulting in the failure to obtain parallel alignment between the faces of trip hook and latching up lever. The result of this defect was that the trip hook and latching up lever did not engage with full latch face surface contact, but instead engaged along a line at the edge of the latching up lever. The defective trip hook mechanism was originally purchased from the Terry Steam Turbine Company in 1985 under the vendor's quality assurance program. The trip hook was installed on the Unit 2 TDAFWP following a pump failure in June 14, 2000. The licensee determined that, because the critical dimensions and characteristics of the trip hook mechanism were not provided to D.C. Cook, it was previously unable to identify the condition. Because the trip hook and latching up lever engaged along a line at the end of the latching up lever rather than full surface area contact (due to the incorrect trip hook latch face angle), it would not have been possible to obtain a 75 percent surface contact during an alignment blue check. Consequently, the licensee determined that use of the incorrect blue check contact alignment acceptance criteria in trip throttle valve maintenance procedure 12-MHP 5021.056.007 (i.e., 75 percent line contact vice 75 percent surface area contact) may have delayed identification of this condition. Specifically, with the incorrect contact angle between the trip hook and latching up lever, a 75 percent surface area blue check contact alignment acceptance criteria would not have been attainable and the installation of the defective trip hook could have been discovered in June 2000. The Unit 2 TDAFWP was repaired and retested satisfactorily on February 24, 2002. After the second failure of the Unit 2 TDAFWP, the licensee performed a visual inspection of the Unit 1 TDAFWP and determined that the contact angle between the trip hook and latching up lever appeared acceptable. The inspectors concluded that the licensee's root cause evaluation was thorough and reasonable.

Because of the repetitive TDAFWP failures, the inspectors reviewed the effectiveness of the licensee's corrective actions for the August 10, 2001 TDAFWP failure. The inspectors determined that the licensee's failure to promptly evaluate information obtained during the investigation of the August 2001 TDAFWP failure contributed to the January 2002 pump failure. On December 13, 2001, the licensee received information from the trip throttle valve vendor regarding the required specifications for alignment between the trip hook and the latching up lever. Specifically, the vendor identified the necessary geometry of the trip hook to avoid generation of a force that would tend to unlatch the trip mechanism. Additionally, the vendor clarified that the 75 percent blue check acceptance criteria for alignment between the trip hook and latching up lever referred to a surface area contact rather than a line criteria. Because the correct blue check contact alignment criteria (i.e., line contact vice area contact) was not known to the licensee immediately following the August 10, 2001 TDAFWP failure, the licensee had previously aligned the trip mechanism using a 75 percent line contact acceptance criteria in August 2001. On December 20, 2002, the licensee performed an operability evaluation under CR 01354104 to evaluate the use of the line contact trip throttle mechanism engagement criteria and concluded that both the Unit 1 and Unit 2 TDAFWPs were operable based, in part, on previous successful testing of the pumps. Although the licensee planned to perform maintenance on the Unit 2 TDAFWP trip throttle valve during the Cycle 13 refueling outage, no corrective maintenance was performed on the Unit 2 TDAFWP to evaluate and correct these potential failure mechanisms prior to the January 18, 2002 failure. Subsequent evaluation by the licensee following the January 18, 2002 failure identified that the 75 percent area blue check contact alignment was not met and that the trip hook did not conform to the required geometric specifications. The inspectors concluded that timely corrective actions to verify trip hook alignment and geometry consistent with vendor recommendations could have prevented the January 18, 2002 pump failure.

Based on this corrective action weakness, the inspectors concluded that the licensee failed to take timely and appropriate corrective action to prevent a repetitive failure of the Unit 2 TDAFWP. As discussed in NRC Inspection Report 50-315/316-01-19(DRP), the inspectors previously determined that the licensee failed to specify the correct trip throttle valve alignment criteria in maintenance procedure 12-MHP 5021.056.007, "Turbine Driven Auxiliary Feed Pump Trip and Throttle Valve Linkage Adjustment," Revision 2. The inspectors concluded that the circumstances and issues associated with the failure to implement appropriate acceptance criteria in 12-MHP 5021.056.007 were closely related to these corrective action weaknesses. Because the failure to take timely corrective action for known deficiencies associated with the trip throttle valve alignment criteria resulted in a repetitive failure of the Unit 2 TDAFWP, the inspectors considered the corrective action weaknesses to be a more significant regulatory concern. Consequently, the inspectors evaluated the identified licensee performance deficiencies, including procedure and corrective action weaknesses, as a single problem resolution issue.

Analysis

The inspectors assessed this issue using the SDP. The inspectors concluded that the failures of the Unit 2 TDAFWP and associated fault exposure unavailability time had a credible impact on safety and was therefore more than a minor concern. Specifically, the TDAFWP provides secondary decay heat removal capability during certain accidents including transients, loss of electrical power events, and some losses of primary coolant events. Consequently, the repetitive failures of the Unit 2 TDAFWP resulting in the unavailability of a train of auxiliary feedwater was associated with the mitigating systems cornerstone. The inspectors performed an SDP Phase 1 assessment and determined that the fault exposure time represented an actual loss of safety function for a single train of auxiliary feedwater for greater than its TS allowed outage time. As discussed below, the inspectors estimated that the August 2001 and January 2002 TDAFWP failures represented approximately 80 days of fault exposure unavailability. Consequently, the fault exposure time exceeded the TS 3.7.1.2 allowed outage time of 72 hours for a single train of auxiliary feedwater. Based on the results from the Phase 1

SDP assessment, the inspectors determined that a Phase 2 SDP assessment was required.

Because of concerns regarding the accuracy of the D. C. Cook Phase 2 worksheets, especially with respect to crediting the motor driven auxiliary feedwater pump cross-tie capability from the other unit, it was determined that it would be more appropriate to perform a Phase 3 SDP assessment using insights from the licensee's updated PRA model. In coordination with the Region III SRA, the following factors were considered for this risk evaluation:

- Because the inspectors were unable to determine the exact time that the TDAFWP became incapable of fully performing its safety function during each of the two fault exposure periods, the inspectors used the "T/2" fault exposure methodology (i.e., one half the time between the pump failure and the previous demonstrated successful operation) to assess this issue. Several factors could degrade the ability of the trip throttle valve to remain engaged during the fault exposure period and result in the inability to determine an exact failure time, including: mechanism wear due to ambient vibration, latch face surface condition, and trip latch mechanism friction. Use of the "T/2"methodology was also consistent with the guidance provided in the response to Frequently Asked Question 291 documented in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2.

- The inspectors did not consider the ability to recover the TDAFWP following an unsuccessful start attempt. This conclusion was based on the inability of the licensee to achieve a successful TDAFWP start during three successive start attempts on August 10, 2001 and the nature of the repair activities required to restore the pump to an available status. The inspectors noted that the successful auto-start of the Unit 2 TDAFWP pump following the January 18, 2002 failure indicated that the TDAFWP could have potentially been recovered following this failure. However, due to the similarity of the root cause for the August 2001 and January 2002 pump failures, the inspectors determined that recovery credit was not warranted.

- Because the August 2001 and January 2002 TDAFWP pump failures shared a common root cause, the inspectors concluded that the fault exposure associated with these failures should be combined to appropriately characterize the risk significance of the issue. The inspectors determined that the last successful TDAFWP start attempt prior to the January 18, 2002 failure occurred on November 2, 2001. Therefore, the January 18, 2002 failure represented an additional 38 days of "T/2" fault exposure for the Unit 2 TDAFWP. Combining this fault exposure with the previous 42 days of "T/2" fault exposure from the August 10, 2001 failure resulted in a total "T/2" fault exposure of approximately 80 days. Based on six successful TDAFWP quarterly surveillance test starts between June 2000 and January 2002 (including a successful surveillance test between the August 2001 and January 2002 failures), the application of a single, longer, fault exposure period for this issue was not considered to be reasonable.

- Based on the licensee’s PRA, the TDAFWP had a risk achievement worth value of 1.41 and the plant had a baseline core damage frequency (CDF) of 4.85E-5 per reactor year.

Using the methodology and assumptions stated above, the SRA determined that 80 days of fault exposure unavailability resulted in an increase in CDF due to internal events to be approximately 4.4E-6 with a very small risk impact due to external initiating events.

Evaluating the impact of this issue on the large early release frequency (LERF), the SRA focused on dual station blackout transients where hydrogen ignitors would not be available. (The ignitors are designed to burn hydrogen at low concentrations and thus reduce the potential for large detonations that could challenge containment integrity.) The SRA reviewed the licensee’s Level 2 evaluation, which provided a more refined tool than IMC 0609, Appendix H, "Containment Integrity Significance Determination Process." Review of the licensee’s cutsets determined that the contribution of the dual unit station blackout was small and the probability of such an event was very low. The final review determined that the change in LERF was approximately 6E-7.

Based on all the contributing factors, the analyst concluded that the risk significance of the inspection finding due to the change in CDF due to internal, external and LERF considerations to be of low to moderate risk significance (White).

<u>Enforcement</u>

10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," 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. 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 failed to take corrective action to prevent repetition of the failure of the Unit 2 TDAFWP, a significant condition adverse to quality. Specifically, the Unit 2 TDAFWP failed to start on August 10, 2001 due to the failure of the trip throttle valve latch mechanism to remain engaged during pump start. On December 13, 2001, the licensee obtained information from the trip throttle valve vendor identifying critical parameters for the trip hook mechanism geometry and alignment. The licensee failed to promptly perform corrective actions to verify that the Unit 2 TDAFWP trip hook conformed to these critical parameters. Consequently, a second failure of the Unit 2 TDAFWP occurred on January 18, 2002 due to the failure of the trip throttle valve latch mechanism to remain engaged during pump start. Subsequent investigation determined that the cause of the August 10, 2001 and January 18, 2002 failures was due to incorrect trip hook geometry and alignment. This issue was determined to be of low to moderate risk significance (White) after a Phase 3 SDP review. Consequently, this issue is identified as Apparent Violation (AV 50-316-02-02-04(DRP)) and is in the licensee’s corrective action program as CR 02018064. URI 50-316-01-19-03 is closed.

4OA3 Event Followup

.1 (Closed) Licensee Event Report (LER) 50-316-2000-012-01: "Failure to Perform Increased Frequency Surveillance on 2 East Containment Spray Pump," Supplement 1. The inspectors reviewed the original LER and determined that the licensee's failure to perform increased frequency surveillance testing on the containment spray pump as required by TS 4.0.5 was a minor issue. The licensee submitted Supplement 1 to LER 50-316-2000-012 to revise the root cause evaluation for the event. The inspectors determined that the information provided in Supplement 1 to LER 50-316-2000-012 did not raise any new issues or change the conclusions of the initial review, which were documented in NRC Inspection Report 50-315/316-00-20(DRP). This LER is closed.

.2 (Closed) LER 50-315-2001-002-00: "Power Range Nuclear Instrumentation Calibration Procedure Not in Conformance with TS". On June 22, 2001, the power range nuclear instrumentation (PRNI) channel functional test for the Unit 1 quarterly calibration was not conducted in accordance with TS 3.3.1.1, Table 3.3-1, Action 2a. This TS requires placing the inoperable PRNI channel in the tripped condition within 1 hour. To meet the TS requirement, the PRNI channel is placed in trip before the detectors are disconnected. Contrary to the TS , the calibration procedure for the PRNI directed that the bistables for the PRNI's be returned to an untripped state while the detectors are still disconnected and after the channel has been inoperable for greater than 1 hour. On August 8, 2001, the licensee received NRC approval of a license amendment to revise TS 3.3.1.1, Table 3.3-1, Action 2a to increase the amount of time allowed to place an inoperable PRNI channel in the tripped condition from 1 hour to 6 hours. On August 9, 2001, the licensee revised the functional test and calibration procedures to implement this TS change. The inspectors reviewed the LER and the licensee's corrective actions and did not identify any significant findings. Although this issue was corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee entered this violation into its corrective action program as CR 01192045. This LER is closed.

4OA6 Meetings

.1 Interim Exits

The results of the Occupational Radiation Safety - Access Controls for Radiologically Significant Areas and ALARA Planning Inspection were presented to Mr. J. Pollock and other members of licensee management at the conclusion of the inspection on February 8, 2002. The licensee acknowledged the findings presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

The results of the Licensed Operator Requalification Program Inspection were presented to Mr. B. Wallace and other members of licensee management at the conclusion of the inspection on March 29, 2002. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Resident Inspector's Exit

The inspectors presented the inspection results to Mr. C. Bakken and other members of licensee management at the conclusion of the inspection on April 5, 2002. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Proprietary information was examined during this inspection but is not specifically discussed in this report.

KEY POINTS OF CONTACT

Licensee

G. Arent, Manger, Regulatory Affairs
C. Bakken, Senior Vice President, Nuclear Generation
R. Brown, Manager, Operations Training
L. Dean, ALARA Supervisor
S. Freeman, Administrative Assistant, Training Department
R. Gaston, Regulatory Compliance Manager
J. Gebbie, Manager, System Engineering
S. Greenlee, Director, Nuclear Technical Services
N. Jackiw, Regulatory Affairs
E. Larson, Director, Operations
J. Mathis, Regulatory Affairs
R. Meister, Regulatory Affairs
D. Moul, Assistant Manager, Operations
W. Nichols, Supervisor, Operator Requalification Training
D. Noble, Manager, Radiation Protection
T. Noonan, Director, Performance Assurance
J. Pollock, Site Vice President
B. Robinson, General Supervisor, Radiation Protection Support
R. Smith, Assistant Director, Plant Engineering
B. Wallace, Manager, Training
D. Wood, Manager, RadChem Environmental
T. Woods, Regulatory Affairs

NRC
A. Vegel, Chief, Reactor Projects Branch 6
S. Burgess, Senior Reactor Analyst
H. González, Nuclear Safety Intern
D. Rivera-Martinez, Nuclear Safety Intern

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-316-02-02-01	URI	Failure to perform adequate maintenance and testing on valve 2-CS-369 resulted in gas binding the Unit 2 west centrifugal charging pump (Section 1R19)
50-316-02-02-02	NCV	Failure to use valid acceptance criteria for stroke time testing the Unit 2 pressurizer power operated relief valves (Section 1R22)
50-316-02-02-03	URI	Contract worker failed to comply with radiological protection instructions and to immediately vacate a work area upon receiving an electronic dosimeter alarm (Section 2OS2.6)
50-316-02-02-04	AV	Failure to take prompt corrective action to prevent repetitive failure of the Unit 2 turbine driven auxiliary feedwater pump (Section 4OA1)

Closed

50-316-02-02-02	NCV	Failure to use valid acceptance criteria for stroke time testing the Unit 2 pressurizer power operated relief valves (Section 1R22)
50-316-01-19-03	URI	Apparent violation of 10 CFR Appendix B, Criterion V for the failure to incorporate adequate quantitative acceptance criteria in turbine driven auxiliary feedwater pump maintenance instructions (Section 4OA1)
50-316-2000-012-01	LER	Failure to perform increased frequency surveillance on 2 east containment spray pump (Section 4OA3)
50-315-2001-002-00	LER	Power range nuclear instrumentation calibration procedure not in conformance with technical specifications (Section 4OA3)

Discussed

50-316-2000-012-00	LER	Failure to perform increased frequency surveillance on 2 east containment spray pump (Section 4OA3)

LIST OF ACRONYMS USED

ADAMS	Agency-wide Documents and Management System
AEP	American Electric Power
AFW	Auxiliary Feedwater
ALARA	As Low As Is Reasonably Achievable
ATR	Administrative Technical Requirement
AV	Apparent Violation
CCP	Centrifugal Charging Pump
CCW	Component Cooling Water
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
DC	Direct Current
DCP	Design Change Package
DIT	Design Information Transmittal
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
ED	Electronic Dosimeter
EHP	Engineering Head Procedure
ESW	Essential Service Water
gpm or GPM	Gallons Per Minute
IHP	Instrumentation Head Procedure
IMC	Inspection Manual Chapter
JO	Job Order
JPM	Job Performance Measure
KV	Kilo-volt
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOR	Licensed Operator Requalification
LORT	Licensed Operator Requalification Training
LTOP	Low Temperature Over-pressure Protection
MHP	Maintenance Head Procedure
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NUMARC	Nuclear Management and Resources Council
OA	Other Activities
OHP	Operations Head Procedure
ORAM	Outage Risk Assessment and Management
OSHA	Occupational Safety and Health Administration
PARS	Publically Available Records
PMI	Plant Manager’s Instruction
PMP	Plant Manager’s Procedure
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
PRNI	Power Range Nuclear Instrument
Radworker	Radiation Worker

RCA	Radiological Controlled Area
RCS	Reactor Coolant System
RO	Reactor Operator
RP	Radiation Protection
RPT	Radiation Protection Technician
RWP	Radiation Work Permit
RWST	Refueling Water Storage Tank
SDP	Significance Determination Process
SI	Safety Injection
SOER	Significant Operating Event Report
SRA	Senior Reactor Analyst
SRO	Senior Reactor Operator
SSC	Structures, Systems, and Components
STP	Surveillance Test Procedure
TBD	To Be Determined
TDAFWP	Turbine Driven Auxiliary Feedwater Pump
TDB	Technical Data Book
TEDE	Total Effective Dose Equivalent
TS	Technical Specification
U2C13	D.C. Cook Unit-2, 13th Refueling Outage
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VCT	Volume Control Tank

LIST OF DOCUMENTS REVIEWED

1R04 Equipment Alignment

Plant Manager’s Procedure (PMP) 5020.RTM.001	Restraint of Transient Material	Revision 1
12-MHP-5021.SCF.001	Scaffolding Guidelines	Revision 0b
01-OHP-5030.001.001	Operations Plant Tours	Revision 19b
01-OHP-4021.016.003	Operation of the Component Cooling Water System During System Startup and Power Operation	Revision 15a
Flow Diagram OP-1-5135-40	CCW [Component Cooling Water] Pumps and CCW Heat Exchangers	Revision 40
Flow Diagram OP-1-5135A-41	CCW Safety Related Loads	Revision 41
Flow Diagram OP-1-5135C-3	CCW Miscellaneous Services Auxiliary Building	Revision 3
Flow Diagram OP-1-5106A-50	Auxiliary Feedwater Unit 1	Revision 50
Condition Report (CR) 02067020	NRC Identified That Procedure 01-OHP-4023-SUP-002, "Restoration of Reserve Power to 4KV [Kilovolt] Buses" Needs to Be Revised to Correct Typographical Error	March 8, 2002
CR 02084028	1-CFA-421 (West CCP [Centrifugal Charging Pump] Coolers CCW Outlet Low Flow Alarm Switch) Indicates High Off-scale and Greater Than Limit of 80 Gallons Per Minute (GPM) Specified in 01-OHP-5030-001-001	March 24, 2002
CR 02085001	NRC Identified Several Scaffolding Installations That Were Contacting Safety Related Equipment	March 25, 2002
CR 02089018	NRC Identified Packing Leak on 1-CCW-404W	March 30, 2002
CR 02089019	NRC Identified Conduit From 1-CMO-420 Has Pulled Out of the Junction Box	March 30, 2002

CR 02089020	NRC Identified Packing Leak on 1-CCW-187W	March 30, 2002
CR 02089023	NRC Identified Packing Leak on 1-CCW-197S	March 30, 2002

<u>1R05</u> <u>Fire Protection</u>

Updated Final Safety Analysis Report, Section 9.8.1	Fire Protection System	
	D. C. Cook Nuclear Plant Fire Hazards Analysis, Units 1 and 2	Revision 8
	D. C. Cook Nuclear Plant Units 1 and 2 Probabilistic Risk Assessment, Fire Analysis Notebook	February 1995
National Fire Protection Association 50A	Standard for Gaseous Hydrogen at Consumer Sites	
Branch Technical Position 9.5-1, Appendix A, Section D.2	Storage of Flammable Gases	
PMP 2270.CCM.001	Control of Combustible Materials	Revision 1
PMP 2270.FIRE.002	Responsibilities for Cook Plant Fire Protection Program Document Updates	Revision 0
PMP 2270.WBG.001	Welding, Burning and Grinding Activities	Revision 0
Plant Manager’s Instruction (PMI) 2270	Fire Protection	Revision 26
12-QHP-4030-STP.009	Inspection of Fire Dampers Protecting Safety-Related Areas	Revision 0
12-PPP-4030-066-021	Inspection of Fire Dampers Protecting Safety-Related Areas	Revision 1
Design Change Package (DCP) 12-DCP-5012	Relocate Main Generator Hydrogen Bulk Storage Tanks from the Unit 1 Side to the Unit 2 Side	Revision 0a
Job Order (JO) R0084548	Perform 18 Month Surveillance of Administrative Technical Requirements Fire Dampers	August 20, 1999

JO R0096948	Perform 18 Month Surveillance of Administrative Technical Requirements Fire Dampers	April 2, 2001
Drawing 12-5717-15	Heating and Ventilating Auxiliary Building Center North, South & West Plan Floor Elevation 609'-0"	Revision 15
CR 99-18790	OSHA [Occupational Safety and Health Administration] Requirement Not Being Met for Reactor Hydrogen System	July 17, 1999
CR 02053067	NRC Identified That Cable Separation in the Unit 1 West CCP Room Did Not Conform to D. C. Cook Specification	February 22, 2002
CR 02064061	List of NRC Identified Issues in the Switchgear Cable Vault	March 5, 2002
CR 02064067	NRC Identified Issue, 1-EIC3 Cable Tray Missing Screws	March 5, 2002
CR 02064070	NRC Identified Excessive Combustible Trash in the Unit 1 Auxiliary Cable Vault	March 5, 2002

1R11 Licensed Operator Requalification Program

	Licensed Operator Requalification Training (LORT) Simulator Evaluation Scenarios for March 6, 2002	
LORT Plan	D. C. Cook Licensed Operator Requalification (LOR) 2 Year Training Plan	2001-2002
Written Exam RQ2526 A-R, RQ2526 A-S	2002 Licensed Operator Requalification Biennial Written Exam - Crew A Week Six - Reactor Operator (RO) and Senior Reactor Operator (SRO)	March 14, 2002
Operating Exam Simulator Scenarios	2002 Two Simulator Scenarios: RQ-E-1712A, RQ-E-2008A	March 15, 2002
Operating Exam Job Performance Measures (JPMs)	2002 Five JPMs: RO-O-E235 (Revision 3), RO-O-E026 (Revision 7), RO-O-S001 (Revision 3), AE-O-E217 (Revision 10), AE-O-N001 (Revision 6)	Various
TI-TROP-01	Training Program Examination Requirements	Revision 8, February 22, 2002

TAP-400	Systematic Approach to Training Implementation	Revision 2, September 25, 2001
TAP-400-040	Conduct of Training	Revision 0, October 8, 1999
TIF (IMP 03)	Weekly Training Attendance Sheets (Year 25 (2001), Crews B, C, D, and Validation)	Year 2001
TIF (IMP 10)	Remediation Qualification Attempt Reports	Year 2002
TIF (IMP 27)	Simulator Crew Evaluation Standards	Revision 5, February 21, 2002
TIF (IMP 29A)	SRO Individual Simulator Performance Evaluations - Crew A - Week Six	March 27-29, 2002
TIF (IMP 29B)	RO Individual Simulator Performance Evaluations - Crew A - Week Six	March 27-29, 2002
TIF (IMP 29D)	Shift Manager Simulator Evaluations - Crew A - Week Six	March 27-29, 2002
TIF (IMP 29E)	JPM Summary Sheets - Crew A	March 27-29, 2002
TIF (IMP 47)	Missed Scheduled Training Notifications	Year 2001-Various
TAP-600-030	Simulator Configuration Control	Revision 1, July 27, 2001
TPD-600-EPT	Emergency Plan Training Program Description	Revision 1, December 20, 2001
TPD-600-LOR	LORT Program Description	Revision 5, October 31, 2001
LORT Task List	Task List Review for LOR Years 26 and 27 (RO/SRO Requal years 2001/2002)	2001/2002
LORT 2 Year Matrix	2 Year Training Cycle (2001/2002) Matrix Listing Period, Theme, Dominant Accident Sequence from IPE, Selected Tasks, Topics, and Procedures	2001/2002
Feedback Forms	Ten LOR Crew Training Assessment Debrief Completed Forms	January 2001 through December 2001
OHI-2070	Training and Qualification	Revision 14, June 06, 2001

OHI-2070, Attachment 8	Operator License/Shift Technical Advisor Status Report	1st Quarter 2002
OHP-4025.001.001	Emergency Remote Shutdown	Revision 3, May 15, 2001
PMP 2070.600	Training Administration and Qualification	Revision 0, May 30, 2001
SA-2000-TRN-001	Training Comprehensive Self Assessment	September 22, 2000
SA-2001-TRN-009	Training Comprehensive Self Assessment	January 11, 2002
PA-01-16	Performance Assurance Audit on Training	February 9, 2001 through March 9, 2001
Computer Listing	Classroom Attendance Computer Listing for RQ-C-2534 (Technical Specifications and Bases for 3/4.1 & 3/4.2), RQ-C-2544 (Emergency Diesel Generator), RQ-C-2573 (Emergency Plan Procedures)	June 2000 through July 2001
Action Time Matrix	Operator Action Time Requirements by Procedure Based on DIT-B-01061-05	November 28, 2000
Medical Records	Selection of Eight Licensed Operator Medical Records (Four SROs and Four ROs)	Various
Medical Records	Computer Print Out - Periodic Report on License Medical Data (Medical Exam Due Dates)	Various
Watch Proficiency Log	Licensed Operator Proficiency Watch Record	1st Quarter 2002 - Various
CR P-00-09097	Condition Report Concerning Inconsistent Procedure Use	June 23, 2000
CR 01046023	Condition Report Concerning Repeat Failure to Properly Store Training Records	February 15, 2001
CR 01047027	Condition Report Concerning Apparent Cause and Extent of Condition Evaluation Not Conducted In Accordance With Requirements	February 16, 2001
CR 02052065	Discrepancies on Annual LOR Examination Material for the First Week of Examinations	February 21, 2002

CR 01054050	Condition Report Concerning Actions Taken for Apparent Cause Not Documented	February 23, 2001
CR 01057044	Condition Report Concerning Failure to Include Cross Reference to Condition Reports	February 26, 2001
CR 01067028	Condition Report Concerning Training Department Compliance with Procedure Requirements	March 08, 2001
CR 02074043	Lack of Validation for a New or Significantly Modified Scenarios	March 13, 2002
CR 02074044	Potential Examination Compromise During Written Exam Administration	March 14, 2002
CR 02087034	Incorrect Emergency Plan Classification Number Referenced in a Simulator Evaluation Scenario - RQ-E-2008A	March 27, 2002
CR 02088010	Requirement to Notify the NRC of Possible 10 CFR 55.25 Condition Based on Medication Prescribed to an Operator	March 29, 2002
CR 02092037	Adequacy of Completing the Plant Accident Notification Forms for Emergency Plan Notifications in Real Time	April 2, 2002
CR 02092039	Appropriateness of Scheduling and Administering the Biennial Written Examination During the First Year of the 2-Year Plan	April 2, 2002
CR 02092042	JPMs Selected During the Annual Operating Examination Having Greater Than 50 Percent Repeatability	April 2, 2002
CR 02092044	Emergency Remote Shutdown Procedure Inconsistencies	April 2, 2002

1R12 Maintenance Rule Implementation

12-EHP-5035-MRP-001	Maintenance Rule Program Administration	Revision 4
NUMARC 93-01	Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants	Revision 2

	Donald C. Cook Probabilistic Risk Assessment Hydrogen Ignitor (DIS) System Notebook	April 13, 1992
	Maintenance Rule Scoping Document for the Hydrogen Ignitor System	October 11, 2001
	Maintenance Rule Scoping Document for the Circulating Water System	Revision 1
	Maintenance Rule Scoping Document for the Compressed Air System	Revision 1
	Maintenance Rule (a)(1) Action Plan Briefing Sheet for the Unit 1 Circulating Water System	No Date
	Maintenance Rule (a)(1) Action Plan for the Unit 1 Circulating Water System	Revision 0 August 3, 2001
	Maintenance Rule (a)(1) Action Plan for the Unit 1 Circulating Water System	Revision 1 March 5, 2002
	Maintenance Rule Performance Monitoring Data for the Compressed Air System	February 27, 2000 through February 27, 2002
	Maintenance Rule Reliability Failures (3/18/00 to 3/18/02) for All Systems Where Failures Have Exceeded Performance Criteria By 50 Percent or Greater	March 18, 2002
EP 01-086	Maintenance Rule Expert Panel Meeting Minutes	May 17, 2001
	System Health Report for the Unit 1 Circulating Water System	October 1, 2001 through December 31, 2001
	System Health Report for the Unit 2 Circulating Water System	October 1, 2001 through December 31, 2001
	System Health Report for the Compressed Air System	October 1, 2001 through December 31, 2001
JO 01079034-01	2-HE-10E Inspect Condenser 24 Inch Supply Piping	January 23, 2002
Work Request 01088050	2-HE-10W Inspect Condenser 24 Inch Supply Piping	February 9, 2002

CR 00-8322	Low Voltage and Current on Unit 2 Trains A and B Lower Ignitors	June 7, 2000
CR 00-8410	Voltage Regulator 2-VR-LDISA-2 Voltage Cannot Be Adjusted	June 8, 2000
CR 00-8412	Voltage Regulator 2-VR-LDISB-4 Output Voltage Cannot Be Adjusted	June 8, 2000
CR 00-9307	The Glow Plug for Hydrogen Ignitor 2-UDISA-A6 Was Replaced but Post Maintenance Testing Was Not Performed as Specified in the JO	June 28, 2000
CR 00-10893	Unit 2 Plant Air Compressor Surged and Could Not be Reloaded to Provide Plant and Control Air	August 4, 2000
CR 00-11711	Expert Panel Approved (a)(1) Status for the Hydrogen Ignitor System Based on Exceeding the Performance Criteria for Unavailability	August 23, 2000
CR 00256041	2-VR-LDISB-4 Output Voltage out of Specification High 122.56 Volts (118 - 122 Volts)	September 12, 2000
CR 00310018	Distributed Ignition Voltage Regulator Transformers Are Defective	November 4, 2000
CR 01012015	The Unit 2 Containment Hydrogen Glow Plugs Are Obsolete and must Be Replaced	January 12, 2001
CR 01046054	A Manual Reactor Trip Was Performed Upon Recognition That the East Main Feedwater Pump Had Tripped on High Back Pressure	February 15, 2001
CR 01047054	Lower Containment Train B Voltage Regulator-4 (2-LDISB-4) Reading High Out of Specification at 230 Volts	February 16, 2001
CR 01061036	Installed Breaker Has Incorrect Size Current Transformers	March 2, 2001
CR 01159049	Re-perform a Maintenance Rule Evaluation for the Condition Described in CR 00-8322	June 8, 2001
CR 01163041	Problem Identified with Maintenance Rule Evaluation for CR 00-8321 Involving a Failure of Glow Plug A6	June 12, 2001

CR 01163043	Discrepancies Identified in Maintenance Rule Evaluation for CR 00256041	June 12, 2001
CR 01171032	CR 00-8412 Maintenance Rule Evaluation Is Inadequate	June 20, 2001
CR 01184053	Hydrogen Ignitor System Maintenance Rule Scoping Document Has No "Trigger Value"	July 3, 2001
CR 01207075	The Maintenance Rule Evaluation Performed Under CR 00-10893 Was Inadequate	July 26, 2001
CR 01277005	Review of Previously Completed Maintenance Rule Evaluation for CR 00330032 Indicates the Evaluation May Be Lacking in Detail, Incorrect, or the Conclusions Not Fully Supported	October 4, 2001
CR 01310021	2-VR-LDISB-4 Will Not Maintain Acceptable Voltage Value	November 6, 2001
CR 02080014	NRC Identified That Maintenance Rule Evaluation of CR 01163041 for a Glow Plug Failure Incorrectly Concluded That the Failure Was Not a Functional Failure	March 21,2002
CR 02080016	NRC Identified Inconsistency in Maintenance Rule Scoping Document for the Distributed Ignition System Regarding System PRA Risk Significance	March 21, 2002
	Maintenance Rule Scoping Document Component Cooling Water System	Revision 1
	System Health Report Component Cooling Water	Period 10/31/01 to 12/31/2001
CR 00356032	Component Cooling Water Maintenance Rule History Review	December 21, 2000
CR 01186039	Maintenance Rule Evaluation for CR 00323052 associated with low CCW flow to a CTS pump was inadequate	July 5, 2001
CR 01101073	2-CCR-440 failed to indicate closed during IST testing	April 11, 2001
CR 00241011	CCW Surge Tank Level Indicator 2-CLR-410 failed	August 28, 2000

CR 01268056	Indications Found in Welds for CCW Heat Exchanger Divider Plate	September 25, 2001
CR 01277001	1-CCR-440 Failed IST Stroke Time Testing	October 4, 2001

1R13 Maintenance Risk Assessments and Emergent Work Control

PMP-2291-OLR-001	On-Line Risk Management	Revision 2
NUMARC 93-01	Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Section 11, "Assessment of Risk Resulting From Performance of Maintenance Activities"	Revision 2
PMP 2291-OLR-001 Data Sheet 1	On-Line Risk Management Work Schedule Review and Approval Form Cycle 40, Week 9	March 10-16, 2002
PMP 2291.OLR.001 Data Sheet 1	On-Line Risk Management Work Schedule Review and Approval Form Cycle 40, Week 11	March 24 - 30, 2002
	Unit 2 Control Room Logs	March 23-24, 2002
	Unit 1 and 2 Supervisors Turnover Logs	March 14, 2002
	Clearance Log, Units 1 and 2	March 14, 2002
JO R0214681	2-PP-10W, Change Oil in Bearing Reservoir	August 16, 2001
JO R0220047	2-PP-10W, Change Oil in Bearing Reservoir	March 24, 2002
CR 02075007	NRC Identified Several Issues Involving Housekeeping, Scaffolding, and Restraint of Transient Material	March 14, 2002
CR 02082003	Failure of Main Turbine Control Valves During Testing	March 23, 2002
CR 02082006	Unit 2 Control Rods Withdrew Continuously Without Temperature Error Mismatch	March 23, 2002
CR 02098031	NRC Identified That Post Maintenance Testing for the 2 West CCW Pump on March 24, 2002 Was Not Performed In Accordance With the Associated Job Order	April 8, 2002

1R15 Operability Evaluations

	D.C. Cook Nuclear Plant Unit 2 Technical Specifications	
	D. C. Cook Nuclear Plant Updated Final Safety Analysis Report	
	NRC Safety Evaluation Report for Cook Nuclear Plant Unit 2 Amendment 185	September 1, 1995
Generic Letter 91-18	Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions	Revision 1
PMP-7030-ORP-001	Operability Determinations	Revision 6
02 OHP 5030.050-001	Main Turbine Oil Overspeed Operability Check	Revision 1
02 OHP 5030-050-002	Main Turbine Overspeed Test	Revision 0
Letter AEP NRC 1168A	Technical Specification Change Request to Delete Turbine Overspeed Protection Requirements	February 15, 1994
	Cook Plant Operations Review Committee Meeting Minutes	February 16, 2002
	Unit 2 Caution Tag Log	March 18, 2002
CR 98-06995	Unit 1 West Essential Service Water (ESW) Pump Room Supply Fans Are Freewheeling Opposite of the Direction for Rotation Indicated by Rotation Arrow Mounted on Fan Housing	November 13, 1998
CR 99-02455	Residual Heat Removal Pumps May Be Experiencing Cavitation	February 11, 1999
CR 99-07602	Calculation PS-4KVD-002 Shows That the Momentary Ratings on the 4 KV Circuit Breakers Are Exceeded for Fault Conditions	April 5, 1999
CR 99-15072	4 KV Degraded Voltage Relay Technical Specification Lower Allowable Limit Is Not Adequate to Protect Connected Safety Related Motors	June 9, 1999

CR 99-17063	The Acceptance Criteria for Filter Maximum Allowable Pressure in Procedure 01-OHP-5030.001.001 Is Not Consistent With Maximum Pressure Considered in Calculation DCCHV12FH01S	June 28, 1999
CR 99-29182	A Revised Control Room Dose Analysis From Westinghouse Will Be Submitted to the NRC for Their Approval	December 15, 1999
CR 00-01079	The Supply Air to the Valve Actuators of ½-CCR-460, ½-CCR-462, ½-CRV-412 Exceeds the Manufacturer's Maximum Allowable Casing Pressure	January 20, 2000
CR 00-01973	Existing Unit 2 Small Bore Piping Concerns That Resulted in Post Restart Design Changes Based on Operability Criteria	February 2, 2000
CR 00-02125	Unit 2 Large Bore Piping Modifications Which Were Identified in the 02-DCP-0164 and 02-DCP-0647 and Most of These Modifications Will Be Implemented Post Restart	February 4, 2000
CR 00-03032	Some of the Small Bore CCW Piping Attached to the Reactor Coolant Pump Thermal Barrier Is Not Adequately Supported to Accommodate the Thermal Movement of the Pumps	February 22, 2000
CR 00-07070	Calculation MD-12-CCW-818-N, Revision 0, Does Not Evaluate the Outside of Containment Forged Head Assembly	May 16, 2000
CR 00279011	The Evaluation for CR 00-6696 Improperly Evaluated the Possibility of Hydraulic Locking in Non-essential Service Water Containment Isolation Valves	October 5, 2000
CR 01032027	Current Procedures Preferentially Align Residual Heat Removal System to Flowpaths That Do Not Have the Required Ventilation From the Hot Sleeve Ventilation System	February 1, 2001
CR 01275031	During Unit 2 ESW Flow Verification Testing, ESW Flow to the Unit 2 West CCW Heat Exchanger Was 30.4 GPM Below the Acceptance Limit of 5520.6 GPM	October 2, 2001

CR 02036021	Document an Aggregate Operability Determination Evaluation to Support Unit 2 Restart Following the February 2002 Refueling Outage	February 5, 2002
CR 02050022	Control Switch 1-101-NRV-152 May Not Be in the Automatic Position Fully	February 19, 2002
CR 02057005	During Performance of 02-OHP-5030-050-001, an Actual Turbine Trip Occurred on the Second Attempt at Overspeed Operability Checks	February 22, 2002

1R17 Permanent Plant Modifications

2-DCP-4821	Install New Impellers in the Containment Spray Pumps (2-PP-9E&W)	Revision 0
Design Change Package Procedure 02-DCP-4821-TP.1	East Containment Spray Pump Performance and Flow Test	Revision 0
Calculation MD-02-ECCS-005-N	Unit 2 Emergency Core Cooling System Pumps Net Positive Suction Head Analysis	Revision 1
Calculation MD-12-CTS-117-N	Spray Additive Eductor Performance	Revision 3
Calculation MD-12-CTS-135-N	Minimum Operability Limits for Containment Spray Pumps	Revision 1
JO 01102007	2-DCP-4821: 2-PP-9E, Install 5 Vane Impeller	February 19,2002
CR 02040037	During Pump Performance Run of 2-PP-9E East Containment Spray Pump Per 2-DCP-4821-TP.1, the Pump Developed Head Was less than the Acceptance Criteria	February 9, 2002

1R19 Post Maintenance Testing

Administrative Technical Requirement 2-EDG-1	Emergency Diesel Generators	
01 OHP 4030-119-022E	East Essential Service Water System Test	Revision 2

12 IHP 6030-RLY-008	ABB Solid State Differential Relay Type 87M Series 419M Calibration and Maintenance	Revision 0, Change 0
12 IHP 6030-RLY-009	ABB Solid State Differential Relay Type 87T Series 419 Calibration and Maintenance	Revision 2a, Change 0
12 MHP 5021-001-023	Manual Diaphragm Valve Maintenance	Revision 6, Change 12
PMP 4043.SLV.001	Sealed/Locked Valves	Revision 4
PMP 2291.PMT.001	Work Management Post Maintenance Testing Matrices	Revision 2
PMP 2291.TRS.001 Data Sheet 1	Troubleshooting Plan for 2 CD Diesel Generator Speed Variations (CR 02039004)	February 8, 2002
Vendor Manual VTD-ITEV-0016	ITT Engineered Valves Maintenance and Instruction Manual for Handwheel Operated Diaphragm Valves	Revision 0
Vendor Manual VTD-ITEV-0017	DIA-FLO Diaphragm Valves Installation, Operation, and Maintenance Manual	Revision 0
Vendor Manual VTD-ITEV-0027	DIA-FLO Handwheel Operated Diaphragm Valves	Revision 2
Engineering Programs Technical Data Book, Figure 1-15.1	Safety Related Pump In-service Test Hydraulic Reference	Revision 73
Engineering Programs Technical Data Book, Figure 1-15.2	Safety Related Pump In-service Test Vibration Reference	Revision 65
JO 01094018	2-CS-369, Replace Diaphragm	February 22, 2002
JO 01225007	2 CD Diesel Generator Returned Fuel Injection Linkage to Approved Configuration	February 11, 2002
JO 01262081	Rebuild the Unit 1 East ESW Pump 1-PP-7E	March 13, 2002
JO 01323026	Investigate Motor Electrical Short of 1-PP-7E	March 13, 2002
JO 02032010	Perform Overcurrent Testing on 2-EZC-C-2B	February 20, 2002

JO 02039004	Troubleshoot/Repair 2-OME-150-CD Control Circuitry	February 12, 2002
JO 02047020	Replace 24 Volt DC [Direct Current] Power Supply PS2 at 2-PS-CGC-19	January 2, 2002
JO 02049054	Troubleshoot and Repair 600 Volt Supply Breaker to the Unit 2 CD2 Battery Charger That Tripped Twice	February 21, 2002
JO 02049080	Investigate, Calibrate, Replace Relay 2-87-DGCD-3 As Required	February 19, 2002
JO 02050025	Investigate, Calibrate, Replace Relay 2-87-T21C-1 As Required	February 20, 2002
JO 02050026	Investigate, Calibrate, Replace Relay 2-87-T21D-1 As Required	February 20, 2002
JO R0208707	Calibrate East ESW Header Pressure Switch	March 12, 2002
JO R0209205	Calibrate Time Delay Relays for East ESW Pump Strainer	March 12, 2002
Dedication Plan HP-0035	Inspection and Refurbishment of Emergency Diesel Generator Governor or Procurement of New Governor	Revision 7
CR 97-3562	SOER [Significant Operating Event Report] 97-1, Potential to Gas Bind Pumps Providing Safety Boron Injection Function	December 10, 1997
CR 02039033	Between February 2, 2002 and February 3, 2002 There Were Ten CRs Initiated to Document Snubbers Installed Backwards	February 8, 2002
CR 02042009	Dedication Plan HP-0035 Needs to Be Revised	February 11, 2002
CR 02047050	The Unit 2 West CCP Showed Signs of Air Entrainment During Attempts to Swap	February 16, 2002
CR 02047051	Check Stem Nut Setting on 2-CS-369	February 16, 2002
CR 02049054	The CD2 Battery Charger Failed to Control Bus Voltage Resulting in Multiple Control Room Annunciators and a Large Current Loading on the Charger	February 18, 2002
CR 02049057	CD Battery Ground	February 18, 2002
CR 02049063	Observed Electrical Flash From 2-RPST-B	February 18, 2002

CR 02049080	During Investigation for 2-BC-CD-2, Found 2-87-DGCD-3 Relay As a Possible Issue for Repairs	February 18, 2002
CR 02049081	Per 2-BC-CD-2 Battery Charger Troubleshooting, Need to Investigate Unit 2 Solid State Protection System Equipment for Possible Damage	February 18, 2002
CR 02050025	Test, Repair, or Replace as Necessary, the Differential Relays for Transformer TR21C Following the 250 Volt DC System Anomaly on February 18, 2002	February 19, 2002
CR 02050026	Test, Repair, or Replace as Necessary, the Differential Relays for Transformer TR21D	February 19, 2002
CR 02050050	Verify Correct Stem Nut Setting on Valve 1-CS-369	February 19, 2002
CR 02072061	During the Coupled Run on the 1E ESW Pump the Instantaneous Overcurrent Alarm Came in and Smoke Was Noted at the Motor Termination Box	March 13, 2002
CR 02080039	NRC Identified That Post Maintenance Testing Specified in JO 02039004 Did Not Incorporate the Guidance Contained in PMP 2291.PMT.001 for Post Maintenance Testing Following Actuator Replacement	March 21, 2002

<u>1R20</u> <u>Refueling and Outage Activities</u>

	D.C. Cook Nuclear Plant Unit 2 Technical Specifications	
	D. C. Cook Nuclear Plant Updated Final Safety Analysis Report	
02-OHP-4021-001-001	Plant Heatup From Cold Shutdown to Hot Standby	Revision 26, C3
02-OHP-4021-001-002	Reactor Start-Up	Revision 22, C0
02-OHP-4021-001-006	Power Escalation	Revision 19, C0
2-OHP-4030-STP-041	Refueling Integrity	Revision 8
12-EHP-4030-002-356	Lower Power Physics Testing With Dynamic Rod Worth Measurement	Revision 0A, C1

12-MHP-4030.031.001	Inspection of Lower Containment and Recirculation Sumps	Revision 0, C1
PMP 4100-SDR-001	Plant Shutdown Safety and Risk Management	Revision 5, C1
	Daily Shift Manager's Logs	February 10, 2002 through February 28, 2002
Memo From R.W. Hennen to Shift Technical Advisors	Unit 2 Time to 200°F and Time to Boil Figures for the Refueling Outage	January 4, 2002
	U2C13 Outage Schedule Shutdown Risk Review	
	D. C. Cook Unit 2 2000 Final Core Map	
	D. C. Cook Unit 2 Cycle 13 Final Core Map	
	D. C. Cook Unit 2 Cycle XII - XIII Core Unload Fuel Handling Movement Sequence	
	D. C. Cook Unit 2 Cycle XII - XIII Core Reload Fuel Handling Movement Sequence	
	D. C. Cook Unit 2 Cycle 13 Core Operating Limits Report	Revision 0
JO R0203029	549 Day Surveillance for Unit 2 Containment Sumps	February 13, 2002
Drawing 12-3902A-0	Recirculation Sump & Screen Repair Containment Building Unit No. 1 & 2	Revision 0
Drawing 12-3902-9	Unit 1 & Unit 2 Containment Building Miscellaneous Frames	Revision 9
CR 02044004	NRC Identified Coating Degradation on Nuts Holding Level Instrumentation Well Lateral Support Brackets	February 13, 2002
CR 02044006	NRC Identified Screens Had a Gap Larger Than the 1/4 Inch Requirement Allowed Per Procedure 12-MHP-4030.031.001	February 13, 2002
CR 02044060	JO 195371-02 Was Taken to Complete Status Without Performing the Required Protective Coatings in the Recirculation Sump	February 13, 2002

CR 02058037	Corrupted Computer File Results in Incorrect Measured Control Rod Worth During Low Power Physics Testing	February 27, 2002

1R22 Surveillance Testing

	D.C. Cook Nuclear Plant Unit 2 Technical Specifications	
	D. C. Cook Nuclear Plant Updated Final Safety Analysis Report	
Updated Final Safety Analysis Report, Section 8.4	Emergency Power System	Revision 17
Technical Specification 3.3.2.1	Engineered Safety Feature Actuation System Instrumentation	Amendment 187
Administrative Technical Requirement 2-EDG-1	Emergency Diesel Generators	Revision 10
	Rapid Event Response Report for CR 02020031	January 21, 2002
02-OHP 4030-001-002	Containment Inspection Tours	Revision 13
02-OHP 4030-202-060	Pressurizer Relief Valve Testing	Revision 0, C0
02-OHP 4030-232-217A	DG2CD Load Sequencing & ESF Testing	Revision 3
02-OHP 4030.STP.007E	East Containment Spray System Operability Test	Revision 16
Design Information Transmittal (DIT) B-00770	Test Procedure Acceptance Criteria for Containment Spray Pumps (1(2)-PP-9E, &9W)	Revision 6
DIT-B-01542	Acceptable Back-leakage Flow Rate Through 2-CTS-120E with Regards to Containment Spray and Recirculation Sump pH Analysis	Revision 0
DIT-B-01544	Acceptable Back-leakage Flow Rate Through Spray Additive Tank Check Valves with Regards to Containment Spray and Recirculation Sump pH Analysis	Revision 1

DIT-B-02327	Stroke Time Acceptance Criteria for 1(2)-NRV-152, -153	Revision 0
Calculation MD-12-CA-004-S	Determination of Available Pressurizer Power Operated Relief Valve Strokes Using the Auxiliary Air Supply	Revision 1
Calculation MD-12-CTS-117-N	Spray Additive Eductor Performance	Revision 3
Calculation MD-12-CTS-135-N	Minimum Operability Limits for Containment Spray Pumps	Revision 1
Engineering Programs Technical Data Book, Figure 2-15.1	Safety Related Pump In-service Test Hydraulic Reference	Revision 59
Engineering Programs Technical Data Book, Figure 2-19.1	Power Operated Relief Valve Stroke Time Limits	Revision 52
Engineering Programs Technical Data Book, Figure 2-19.1	Power Operated Relief Valve Stroke Time Limits	Revision 53
Engineering Programs Technical Data Book, Figure 2-19.9	Diesel Generator Pot Settings	Revisions 30 & 31
Flow Diagram OP-2-5144	Containment Spray Unit 2	Revision 50
Clearance Order 2012025	Isolate West Containment Spray Pump	February 16, 2002
CR 01173001	The Vibration Alert Limits Are Higher Than the Action Limits for the #2 Boric Acid Transfer Pump	June 21, 2001
CR 01255059	TDB Figure 2-15.1 Allows CCP Interaction Delta Pressure In Excess of Design Basis Calculation	September 12, 2001
CR 01270017	Untimely Engineering Evaluation, Resultant Re-baseline Determination, and TDB Change for Power Operated Relief Valve (PORV) 1-MRV-213 Delayed the Unit 1 Ascension to Mode 4	September 27, 2001
CR 01292027	Non-conservative Acceptance Criteria in TDB Figure 2-15.1 for 2-PP-26N	October 19, 2001

CR 01324040	Non-conservative Acceptance Criteria in TDB Figure 2-15.1 for 2-PP-10E	November 20, 2001
CR 02046013	Containment Annulus Pipe Tunnel Sump Pump 2-PP-61A Did Not Meet Acceptance Criteria at Step 5.1.5 of Surveillance Procedure 2-EHP-4030-231-240 for GPM	February 15, 2002
CR 02046050	NRC Identified Unit 2 Pressurizer PORVs 2-NRV-152 & 153 Were Retested Using TDB Stroke Times and a Testing Procedure That Had Not Been Revised to Contain the Corrective Actions to Ensure Operability In Accordance With Information Contained in DIT-B-02327-00	February 15, 2002
CR 02050067	NRC Identified Minor Quantities of Debris in Lower Ice Condenser Following Unit 2 Refueling Outage	February 19, 2002
CR02051076	Resident Inspector Identified Dry Boric Acid on 2-IRV-120	February 20, 2002
CR 02051077	NRC Identified Dry Boric Acid at the Pipe Caps of Valves 2-CS-441-1 and 2-CS-441-2	February 20, 2002
CR 02051078	NRC Identified Dry Boric Acid on Transmitter 2-NFP-212	February 20, 2002
CR 02052001	NRC Identified Dry Boric Acid on Valve 2-NPI-110-V1	February 21, 2002
CR 02052002	NRC Identified Dry Boric Acid on Valve 2-IMO-54	February 21, 2002
CR 02052003	NRC Identified Dry Boric Acid on Valve 2-CS-450-4	February 21, 2002
CR 02052008	NRC Identified Dry Boric Acid on Containment Spray Header Piping	February 21, 2002
CR 02052010	NRC Identified Containment Inspection Tour Deficiencies Following Unit 2 Refueling Outage	February 21, 2002
CR 02052039	NRC Identified That Abandoned Conduit Left in Containment Contrary to Design Change Instructions	February 21, 2002
CR 02053063	NRC Identified Minor Equipment Storage Deficiencies in the Auxiliary Building	February 22, 2002

1R23 Temporary Plant Modifications

	D. C. Cook Nuclear Plant Updated Final Safety Analysis Report	
Temporary Modification 2-TM-00-54-R1	Installation of Noise Filtering Resistors on Cables 2-4450PB-2 for 2-ILA-111 and 2-5658PB-2 for 2-ILA-121	November 16, 2001
12-EHP-5040-MOD-001	Temporary Modifications	Revision 9
JO 01320005	Install Temporary Modification 2-TM-00-54-R1 on Cable 2-4450PB-2 for 2-ILA-111	November 17, 2001
10 CFR 50.59 Safety Screening 2000-1940-00	Original Revision of 2-TM-00-54-R0, Installation of Noise Filtering Resistor on Cable 2-5658PB-2 for 2-ILA-121	September 19, 2000
10 CFR 50.59 Applicability Determination 2001-1408-00	Revision to Temporary Modification 2-TM-00-54-R1 to Include Cable 2-4450PB-2 for 2-ILA-111	November 16, 2001
Memo from T. Craven to D. Hafer	Waiver of Design Review Board for 2-TM-00-54-R1	November 16, 2001
CR 01355035	Replace the Currently Installed Foxboro Accumulator Level Alarm Transmitter With an Equivalent Rosemont Transmitter	December 21, 2001
CR 02086013	Lost Implementation Checklist (Data Sheet 8 of Temporary Modification Procedure 12-EHP-5040-MOD-001, Revision 8) for Temporary Modification 2-TM-00-54, "Installation of Noise Filtering Resistors on Cable 2-4450PB-2 for 2-ILA-111"	March 27, 2002

2OS1 Access Controls For Radiologically Significant Areas

PMP-6010-RPP-003	High, Locked High, and Very High Radiation Area Access	Revision 10
CR 02029056	Unit-2 Reactor Head Set High Radiation Area Posting	January 29, 2002

CR 02025007	Access to Restricted Areas Poorly Controlled During RCS [Reactor Coolant System] Cleanup Post Shutdown	January 25, 2002

2OS2 ALARA [As Low As Reasonably Achievable] Planning and Controls

	U2C13 RWP [Radiation Work Permit] Dose Totals Reports and Cook Plant Daily ALARA Reports	January 20, 2002 through February 7, 2002
	Listing of Outage Generated CRs Coded to RP [Radiation Protection] Issues	January 19, 2002 through February 7, 2002
PMP-6010.ALA.001	ALARA Program - Review of Plant Work Activities	Revision 11
12-THP-6010.RPP.006	Radiation Work Permit Processing	Revision 17
12-THP-6010-RPP-018	Controls for Radiological Risk Significant Work Activities	Revision 0
RWP # 022136 and Associated ALARA Plan	Scaffold Activities in the Containment and Auxiliary Buildings	RWP Revision 05
RWP # 022170 and Associated ALARA Plan	U2C13 DCP 525 - Modify/Replace Pressurizer Spray Line Temperature Sensor	RWP Revision 05
RWP # 022119 and Associated ALARA Plan	Temporary Shielding	RWP Revision 02
RWP # 022152 and Associated ALARA Plan	CRDM [Control Rod Drive Mechanism] Inspections	RWP Revision 00
RWP # 022134 and Associated ALARA Plan	Containment Insulation	RWP Revision 02
RWP # 022140 and Associated ALARA Plan	Steam Generator & Diaphragm Activities	RWP Revision 00
RWP # 022141 and Associated ALARA Plan	Steam Generator Primary Work - Platform Activities	RWP Revision 08
PMP-6010.ALA.001	ALARA In-Progress Review for Scaffold Support Activities	January 22, 24 and February 1, 2002
PMP-6010.ALA.001	ALARA In-Progress Review for Pressurizer Spray Line Temperature Sensor Replacement	February 5, 2002

PMP-6010.ALA.001	ALARA In-Progress Review for Steam Generator Primary Activities	February 4, 2002
CR 02019069	Reactor Flood Up Specification - Shutdown Chemistry	January 19, 2002
CRs 02022024, 02029013, 02019072, 02020020, 02020021, 02022024, 02021064, 02021065, 02023006, 02023008, 02024011, 02023043, 02028039, 02029013, 02029016, 02033063, 02033066, 02034034, 02035008, 02038002	Radworker [Radiation Worker] Performance Related Issues	January 19, 2002 through February 7, 2002
CR 02031019	Additional Dose During Scaffold Work	January 31, 2002
CR 02025001	Scaffold Activities	January 25, 2002
TEDE [Total Effective Dose Equivalent] ALARA Evaluations For RWP #s 02-2170; 02-2152; 02-2134; 02-2140; and 02-2141	Relocate Temperature Sensor; Under Reactor Head Inspections; Insulation Removal; Steam Generator Manway Activities; and Steam Generator Eddy Current Activities	Various dates between November 28, 2001 and January 24, 2002
Rad/Chem - Environmental Department Self-Assessment Report SA-2001-RPS-009	Readiness of ALARA Outage Planning for U2C13	August 2001
Performance Assurance Field Observations	Field Observations # 01-L-043, 02 A-003, 01-L-036, 01-K-061, 01-F-032, 01-K-040, 02-A-072, 02-A-112, 02-A-081, 02-A-107, 02-A-117, 02-B-005, 02-A-109, 02-A-130, 02-A-026, 02-A-122, 02-A-124	Various dates between November 14, 2001 and February 4, 2002
CR 02029016 and related preliminary investigation information	Individual Disregarded RP Technician Directive and ED Dose Alarm While Working in U2 Lower Containment	January 29, 2002 and related information through January 31, 2002
12-THP-6020-CHM-110	RCS Chemistry - Shutdown/Refueling	Revision 8(c)
	D.C. Cook Nuclear Power Plant 2001 Dose Reduction Five Year Plan	December 2001

4OA1 Performance Indicator Verification

02 OHP 4025.001.001	Emergency Remote Shutdown	Revision 3
02 OHP 4022-055-003	Loss of Condensate to Auxiliary Feedwater Pumps	Revision 6a
02 OHP 4025.LS-2	Start-Up AFW [Auxiliary Feedwater]	Revision 0
02 OHP 4025.LS-3	Steam Generator 2/3 Level Control	Revision 1
JO 02018064	2-PP-4 TDAFWP [Turbine Driven Auxiliary Feedwater Pump] Tripped Shortly After Startup	February 19, 2002
DIT-S-01037	Auxiliary Feedwater Pump Steam Turbine Drive Trip and Throttle Valve Latch Hook Linkage Machining Information	Revision 1
	Receipt Inspection Report Purchase Order/Contract 03157-821-5X	May 27, 1986
CR 01222001	While Performing Fill and Vent Procedure for the TDAFWP, the Pump Failed to Start	August 10, 2001
CR 01354104	Prompt Operability Determination for Both Unit’s TDAFWPs. Trip Throttle Valve Latch Faces Have Not Been Maintained as Per Vendor Information	December 20, 2001
CR 02018064	TDAFWP Trip Throttle Valve Tripped Shortly after Start of the Pump During Performance of Time Response Test	January 18, 2002
CR 02019071	Performance Assurance Identified That Operability Determination for CR 02018064 and CR 01354104 for the TDAFWP Were Inadequate	January 19, 2002

4OA3 Event Followup

	D.C. Cook Nuclear Plant Unit 1Technical Specifications	
	D.C. Cook Nuclear Plant Unit 2 Technical Specifications	

Licensee Event Report (LER) 50-316-2000-012-00	Failure to Perform Increased Frequency Surveillance on 2 East Containment Spray Pump
LER 50-316-2000-012-01	Failure to Perform Increased Frequency Surveillance on 2 East Containment Spray Pump, Supplement 1
LER 50-315-2001-002-00	Power Range Nuclear Instrumentation Calibration Procedure Not in Conformance with Technical Specifications