June 14, 2000

Mr. R. P. Powers
Senior Vice President
Nuclear Generation Group
American Electric Power Company
500 Circle Drive
Buchanan, MI 49107-1395

SUBJECT: D. C. COOK INSPECTION REPORT 50-316/2000003(DRP)

Dear Mr. Powers:

On May 22, 2000, the NRC completed the Restart Readiness Assessment Team Inspection at your D. C. Cook Unit 2 facility. The purpose of the inspection was to evaluate the readiness of plant hardware, plant staff, and management programs to support a safe restart and continued operation of D. C. Cook Unit 2. The team focused on those processes and programs which could affect safe reactor startup, and included the areas of operations, maintenance, surveillance testing, engineering, and corrective actions for Restart Action Matrix Items. Additionally, the team observed control room activities during a continuous 72-hour period and performed extensive system walkdowns.

Through observation of routine operating, maintenance, and testing activities, the team concluded that shift turnovers, procedural adequacy and adherence, communications, log keeping, knowledge and awareness of equipment status, and control of plant activities were adequate. Additionally, we noted that the surveillance test activities reviewed were properly implemented. While the team concluded that operations personnel were capable of safely operating the plant, human performance errors of minor consequence, occurred, which indicated a need for continued management focus in this area. Specifically, deficiencies were identified in the areas of control room operator awareness of abnormal plant conditions and the work control process and its interface with the control room staff. We recognize that your staff has implemented corrective actions to address these problem areas. Overall, the team concluded that operator performance was adequate for restart.

The materiel condition of Unit 2 was considered adequate for the affirmed plant systems walked down by the team. However, the team identified a number of examples of materiel condition and equipment configuration issues, including an isolated example of an undocumented modification on the fuel oil storage tank vent line. These issues were entered into your corrective action program and we understood that your staff would perform additional plant area reviews before restart. Overall, substantial progress was observed in restoration of plant equipment in preparation for plant restart. However, due to the number of plant systems which had not yet been restored to an operational status, including containment, Case Specific Checklist (CSC) Item 13, Systems and Containment Final Readiness Review, remained open, at the conclusion of this inspection.

The team considered the programmatic and functional area readiness affirmation scope and process comprehensive. Detailed reviews and affirmations were completed for 94 programs and plant functional areas. Based on a sample of the program and functional area reviews, the team considered that the station programs and functional areas were ready to support restart. Therefore CSC Item 14/14G, Programmatic Final Readiness Reviews, and CSC Item 15/15B, Functional Area Final Readiness Reviews, were closed.

Previously, the NRC had identified as CSC Item 11, concerns associated with the Hydrogen Mitigation System Operability and Materiel Condition. Through testing and analysis, your staff adequately demonstrated that post accident containment hydrogen levels would remain below 4 percent and therefore, CSC Item 11 was closed. The team also reviewed a sample of modifications implemented during the extended shutdown. The modifications reviewed were properly designed, installed, and tested, which indicated that the modification process was functioning effectively. We also considered assessments of the engineering department effective and that the assessment findings were adequately resolved. However, the team identified examples of errors associated with calculations, which indicated a lack of coordination and control in the calculation process that warrants additional management attention.

Based on the results of this inspection, the NRC has determined that six Violations of NRC requirements occurred. These Violations are being treated as Non-Cited Violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the Violations or severity level of the NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region III, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter (and its enclosure) will be placed in the NRC Public Document Room and is available on the NRC Public Electronic Reading Room (PERR) link at the NRC home page, http://www.nrc.gov/NRC/ADAMS/index.html.

Sincerely,

/RA/

John A. Grobe, Director
Division of Reactor Safety

Docket No. 50-316
License No. DPR-74

Enclosure: Inspection Report 50-316/2000003(DRP)

See Attached Distribution

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Sincerely,

John A. Grobe, Director
Division of Reactor Safety

Docket No. 50-316
License No. DPR-74

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REGION III

Docket Nos:	50-316
License Nos:	DPR-74
Report No:	50-316/2000003(DRP)
Licensee:	American Electric Power Company 500 Circle Drive Buchanan, MI 49107-1395
Facility:	D. C. Cook Nuclear Generating Plant, Unit 2
Location:	1 Cook Place Bridgman, MI 49106
Dates:	May 8 through 22, 2000
Inspectors:	J. Lara, Team Leader, Region III M. Holmberg, Assistant Team Leader, Region III J. Brand, Resident Inspector, Region I C. Brown, Resident Inspector, Region III K. Coyne, Resident Inspector, Region III M. Giles, Resident Inspector, Region II T. Hoeg, Resident Inspector, Region I D. Kern, Senior Resident Inspector, Region I P. Krohn, Resident Inspector, Region III S. Thomas, Resident Inspector, Region III A. Walker, Reactor Inspector, Region III K. Walton, Resident Inspector, Region III
Approved by:	A. Vegel, Chief Reactor Projects Branch 6 Division of Reactor Projects

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EXECUTIVE SUMMARY

D. C. Cook Unit 2
NRC Inspection Report 50-316/2000003(DRP)

The Restart Readiness Assessment Team Inspection evaluated the readiness of plant hardware, plant staff, and management programs to support a safe restart and continued operation of D. C. Cook Unit 2. During this inspection period, the team conducted 72 hours of continuous control room observations to evaluate activities in the operations, maintenance, and engineering performance areas.

By letter dated September 17, 1999, the NRC transmitted the updated Case Specific Checklist (CSC) for the D. C. Cook Nuclear Power Plant which identified issues requiring resolution before restart of the Cook Plant. This inspection included evaluation of the licensee corrective actions for resolution of CSC Items 11, Resolution of Hydrogen Mitigation System Operability and Materiel Condition Issues, 13/13B, Systems and Containment Final Readiness Review, 14/14G, Programmatic Final Readiness Reviews, and 15/15G, Functional Area Final Readiness Reviews.

Open Items identified in NRC inspection reports and Licensee Event Reports requiring inspection/resolution prior to restart of the Cook Plant have been identified in the Restart Action Matrix (RAM) approved by the NRC Manual Chapter 0350 Oversight Panel. In the RAM, open Items were identified with designated inspection priorities. The higher priority inspection issues received a more in-depth review during this inspection. Based on adequate corrective actions for resolution of Items selected for the more in-depth review, reasonable assurance exists that corrective actions for the similar lower priority inspection issues are adequate. The intent of selecting a sample of Items for more in-depth review was to improve NRC efficiency in assessing the restart readiness of the plant and to ensure an appropriate focus on the issues most important from a safety and risk perspective.

Case Specific Checklist Items

- Because of the number of plant systems which had not yet been affirmed and restored to an operational status, Case Specific Checklist Item 13 associated with Systems and Containment Readiness, remained open at the conclusion of the inspection (Section O2.1).

- The licensee completed detailed reviews and affirmations for 94 plant programs. Based on a sample of program area reviews, the team considered that the station programs were functioning adequately to support restart. Therefore Case Specific Checklist Item 14/14G, Programmatic Final Readiness Reviews, was closed (Section O8.1).

- The team concluded that the functional area assessments were sufficiently objective, comprehensive and conducted in sufficient detail, with appropriate corrective action resolution, to ensure departmental readiness in support of Unit 2 restart. Therefore, Case Specific Checklist Item 15/15B, Resolution of Functional Area Final Readiness Reviews, was closed (Section O8.2).

- Through testing and analysis, the licensee adequately demonstrated that post accident containment hydrogen levels would remain below 4 percent. Therefore, Case Specific

Checklist Item 11 associated with Hydrogen Mitigation System Operability was closed (Section E8.1).

Operations

- Overall, the team concluded that operator performance was adequate for restart. While the team concluded that operations personnel were capable of safely operating the plant, human performance errors, of minor consequence, occurred, which indicated a need for continued management focus in this area. Specifically, weaknesses were identified in the areas of control room operator awareness of abnormal plant conditions and the work control process and its interface with the control room staff (Section O1.1).

- With a few exceptions, operational problems were being documented in accordance with the licensee's administrative procedures. Three-way communications were consistently and effectively used by operations department personnel for all observed orders and directions that involved operation of plant equipment or exchange of critical information related to the plant or plant equipment (Section O1.2).

- Briefings conducted by the unit supervisors were effective in conveying plant status, shift priorities, planned evolutions, problems with plant equipment, and evolutions in progress. Personnel in the control room were alert and performed their assigned duties in a professional manner throughout the period of observation (Section O1.2).

- The number of poorly planned work activities reaching the control room created excessive, unnecessary challenges to the operators in maintaining good control of plant configuration and status (Section O1.2).

- In general, the team observed control room shift personnel attentive to assigned duties. Operators responded to annunciators and alarms in accordance with applicable standards and procedures and were generally knowledgeable about equipment status (Section O1.3).

- The team identified a weakness in operator control board awareness relating to abnormal system configurations and ongoing work activities including operators failing to identify promptly loss of a steam generator level indicator and the operators failing to anticipate a pressure transient following a reactor coolant pump start (Section O1.3).

- The team identified that the boric acid flow rate was set too low for the existing reactor coolant system boron concentration, which was considered a Non-Cited Violation of Technical Specification 6.8.1. Setting the boric acid flow rate lower than required could have resulted in an unplanned boron dilution. Fortuitously, the system makeup blend control switch was in the off position, such that automatic system makeup flow (unplanned boron dilution) would not have occurred (Section O1.3).

- Control room shift staffing met Technical Specification requirements and was sufficient to support safe plant operation. Shift turnovers were conducted professionally, clearly conveying status changes for important plant equipment, and addressing planned/ongoing evolutions (Section O1.4).

- Non-licensed operators used formal communications and displayed good ownership of problems and challenges occurring in their assigned areas (Section O1.5).

- Increased attention to changing plant conditions was needed for non-licensed operators, as evidenced by indications of unexpected vacuum in a steam generator blowdown flashtank and an over-ranged residual heat removal pump suction pressure gage that were not identified by the operators. Overall, non-licensed operators were capable of adequately performing their required duties (Section O1.5).

- The team performed extensive assessments of plant performance during this inspection, including a 72-hour period of continuous control room observations. Based on these control room observations, the team determined that Restart Action Matrix Item C.3.3.e Assessment of Plant Staff Performance During Restart and Sustained Control Room Observations was closed (Section O1.6).

- A detailed readiness review process had been conducted on plant systems to ensure system readiness in support of plant startup and power operation. Further, the System Readiness Review Board was effective in reviewing and probing system manager readiness reports with a clear focus on reactor plant safety (Section O2.1).

- The team identified a number of material condition issues not previously identified by the licensee during system walkdowns. The licensee's corrective actions included additional area walkdowns to identify materiel condition issues prior to restart (Section O2.1).

- The licensee had developed and implemented a well defined and controlled process for ensuring the availability of Unit 1 equipment required for the safe shutdown of Unit 2 (Section O.2.2).

- The process to review and affirm systems as ready for restart was detailed and produced acceptable system status. For the systems reviewed by the team, the licensee had adequately returned the systems to service (Section O2.3).

- A number of systems remained to be affirmed and therefore, Restart Action Matrix Item C.4.a, Operability of Technical Specification Systems remained open (Section O2.3).

- The startup and power ascension plan specified appropriate individual secondary system readiness requirements for the various plant mode-hold milestones and 13 of 23 systems had been affirmed and reasonable controls were in place for readiness affirmation of the remaining systems before restart. Therefore, Restart Action Matrix Item C.4.b, Operability of Required Secondary and Support Systems, was closed (Section O2.4).

- A large amount of pre-startup testing was not yet complete and therefore, Restart Action Matrix Item C.4.c, Results of Pre-startup Testing remained open (Section O2.5).

- The team confirmed that six safety related systems were properly aligned and capable of performing their design function in the current mode of operation (Section O2.6).

- A number of systems remained to be affirmed and system lineups established prior to restart. Therefore, Restart Action Matrix Item C.4.d, Adequacy of System Lineups remained open (Section O2.6).

- The team considered the surveillance test and operating procedure instructions adequate and procedure use good, including pre-evolution briefings, communications, and peer-checking. Overall procedure quality was considered adequate for the operators to safely restart Unit 2 (Section O3.1).

- One Non-Cited Violation of Technical Specification 6.8.1 was identified regarding the failure to perform biennial reviews of active procedures (Section O3.1).

- Adequate controls for plant drawings were in effect, to ensure that the operating crews had accurate drawings which reflected the current plant configuration (Section O3.2).

- The Startup and Power Ascension Plan contained comprehensive test requirements, reviews, and verifications to ensure plant readiness for restart. Appropriate controls were established to ensure lessons learned from the Unit 2 restart were documented and tracked for management review and integration into the Unit 1 restart plan (Section O3.3).

- The Power Ascension Schedule was not sufficiently developed and reviewed at the close of the inspection to support plant restart. Therefore, Restart Action Matrix Item C.4.g, Adequacy of the Power Ascension Testing Program remained open (Section O3.3).

- Operator training in preparation for restart was effective in re-familiarizing personnel to operating conditions (O5.1)

- Performance Assurance audits were more critical of operations performance than the operations department self-assessment audits. The combined efforts of the Performance Assurance and operations department, provided sufficient assessment capability to identify problems challenging operators (Section O7.1).

Maintenance

- Observed surveillance activities were properly controlled and documented and demonstrated system operability. Pre-job briefings were detailed and effective in preparing station personnel for performing the tests (Section M1.1).

- Observed maintenance work was performed by knowledgeable personnel in accordance with approved job orders and administratively controlled by the station's work control center (Section M1.2).

Engineering

- The team reviewed a sample of modifications implemented during the extended shutdown. These modifications were properly designed, installed, and tested, which indicated that the modification process was functioning effectively (Section E1.1).

- A potential source of confusion for the operators was identified in the Control Room Temporary Modification Log Index associated with approved temporary modifications, which had not been installed. Based on review of the process, selected packages, and the corrective actions implemented, the overall temporary modification process was considered adequate (Section E1.2).

- The team considered the engineering department self-assessments effective and resolution of assessment findings adequate (Section E7.1).

- The team identified inadequate resolution of one engineering self-assessment finding associated with a calculation for the control room habitability, which was considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III. This issue stemmed from a lack of consideration for the operational alignment of the system and indicated a lack of coordination and control in the calculation process (Section E7.1).

- The team considered the Performance Assurance department audits of engineering adequate and the findings appropriately resolved (Section E7.2).

- The licensee demonstrated through post modification testing, on the 2 AB emergency diesel generator, that the modified emergency diesel generator air system would support sustained emergency diesel generator operation. Therefore, the team considered that operability of the emergency diesel generators was adequately resolved and LER 50-315/99011-00 (Restart Action Matrix Item R.1.28) was closed (Section E8.2).

- Inconsistencies were identified in calculations used to determine a minimum fuel oil storage tank level, which indicated a lack of coordination and control in the calculation process (Section E8.3).

- An uncontrolled document was used to make a surveillance procedure change, which directly contributed to the incorporation of an incorrect value for minimum fuel oil storage tank level, which was considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III. This issue stemmed from a lack of coordination and control in the calculation process (Section E8.3).

- The team identified a shroud installed on the CD fuel oil storage tank vent line, that had not been incorporated into the vent line drawing and was considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III. The failure to identify this issue during previous Expanded System Readiness Review walkdowns, indicated that this process was not fully effective in the restoration of system materiel condition (Section E8.3).

- The team identified that emergency diesel generator surveillance procedure acceptance criterion for the power factor was not supported by documented calculations and did not consider the potential instrument inaccuracies, which was considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III. The lack of supporting calculations for the emergency diesel generator power factor acceptance criteria indicated a lack of coordination and control in the calculation process (Section E8.3).

Report Details

Summary of Plant Status

The D. C. Cook Unit 2 facility remained shutdown during this inspection period. The licensee was completing system readiness activities and returning systems to service following an extended outage in preparation for entering Mode 4.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

Overall, the team concluded that operator performance was adequate for restart. While the team concluded that operations personnel were capable of safely operating the plant, human performance errors of minor consequence, occurred, which indicated a need for continued management focus in this area. Specifically, weaknesses were identified in the areas of control room operator awareness of abnormal plant conditions and the work control process and its interface with the control room staff. Examples of these weaknesses are discussed in the following sections.

O1.2 Control Room Observations

a. Inspection Scope

The team conducted observations of routine control room activities during a continuous 72-hour period using Inspection Procedure 93802, “Operational Safety Team Inspection,“ as guidance. During this observation period, the team observed ongoing plant operations, log-keeping practices, communications, command and control, control room decorum, and work control.

b. Observations and Findings

b.1 Log Keeping Practices

The team reviewed all control room Power Log Reports generated during the 72-hour continuous control room observation period, as well as a selection of Power Log Reports generated before the inspection week. The Shift Manager Logs were reviewed to verify compliance with Procedure OHI-2212 “Narrative Logkeeping.” Procedure OHI-2212 requires significant annunciators to be logged as well as sufficient detail to allow reconstruction of shift activities. The team performed an assessment to determine whether operational problems were being documented in accordance with the licensee's administrative procedures. In general, the types of information required to be recorded in the control room logs by site administrative procedures, were being recorded. A few examples were identified where operators did not log abnormal or plant conditions. Representative examples are discussed below:

- The Number 24 Reactor Coolant Pump (RCP) Number 2 seal standpipe level alarm was listed on the shift turnover sheet as alarming about every 20 minutes,

and the control room operators were timing the frequency of the alarms for trending purposes. However, no entries were made in the control room logs regarding this frequent annunciator alarm.

- Following receipt and followup to an unexpected low temperature alarm associated with the refueling water storage tank, the reactor operator (RO) failed to make a log entry about either the alarm or the results of the alarm investigation.

- The logs indicated that the containment spray nozzle surveillance test began at 3:25 p.m. on May 9, 2000. However, the test had been postponed for a day and additional log entries were not made. Therefore, the log did not accurately reflect plant configuration and activities.

b.2 Communications

During the control room observations, the team monitored communications among shift crew personnel within the control room and between the control room and plant personnel to confirm adherence with administrative procedures. Routine control room communications were effective, instructions were acknowledged, and receipt of instructions were verified. The control room operators' alarm responses and the ensuing communications with the unit supervisor (US) were consistent and in accordance with administrative procedures. Control room environment was observed to be adequate for clear communications. However, operations staff were not requiring other staff to meet three-way communication expectations in their dealings with the operators.

The team also observed numerous briefings for planned maintenance and surveillance activities. The briefings were normally conducted in an orderly and efficient manner, necessary information was clearly communicated and acknowledged. The US routinely stressed the importance of communication for evolutions to be successful and ensured that the responsibilities and authorities of all personnel involved in the evolution were clearly stated and understood.

b.3 Command and Control

The team observed numerous interactions and interfaces between shift management and other personnel during the control room observation period. The team observed that the US was the single point of accountability for the assigned unit, displayed command authority over the operators and plant operations within, provided direct oversight of the operators assigned to the unit, and routinely reviewed the Technical Specifications (TS) regarding existing and potential conditions associated with planned evolutions. The US was also observed to adequately monitor and control access to activities in the control room; authorize test, surveillance, and maintenance activities; and conduct acceptable briefings for infrequently performed evolutions and risk significant activities.

b.4 Control Room Decorum

During the 72 hours of continuous control room observation, the team was able to assess the formality of control room operations under a variety of conditions ranging

from periods of very low activity to periods intensely focused on specific evolutions. The USs exhibited direct responsibility for minimizing control room distractions and were cognizant of activities that could distract the attention of the control room operators from their assigned duties. Unit assist ROs were observed to routinely perform tasks and surveillances, thus allowing the Unit RO to monitor the unit without distraction. No activities were observed that could adversely affect the ability of individuals or equipment to perform their intended safety function.

b.5 Work Control

The team observed a high level of work activities coming to the control room, many of which had not received sufficient preparation in the work control center. Examples included the US or operators having to modify system tagouts, prevent tagging out both backup power supplies to Bus 21, not allowing a technician to manipulate a system valve, and declining to start a surveillance test that had conflicting requirements to a test already in progress. Additionally, on May 9, 2000, the operators un-necessarily tagged the East essential service water (ESW) and component cooling water (CCW) pumps out of service for over a day when no work was performed, due to maintenance and engineering staffs being unprepared to support the planned work. During this time the plant was unnecessarily placed in a higher risk configuration for a longer time until the ESW/CCW tagout was cleared. The number of poorly planned work activities reaching the control room created excessive, unnecessary challenges to the operators in maintaining good control of plant configuration and status.

c. Conclusions

The Unit Power Log Report and Shift Manager Log were in compliance with administrative procedure requirements. With a few exceptions, operational problems were being documented in accordance with the licensee's administrative procedures. Three-way communications were consistently and effectively used by operations department personnel for all observed orders and directions that involved operation of plant equipment or exchange of critical information related to the plant or plant equipment.

Briefings conducted by the USs were effective in conveying plant status, shift priorities, planned evolutions, problems with plant equipment, and evolutions in progress. The briefings were also determined to be effective in ensuring individuals involved in the pertinent evolutions were fully briefed. Personnel in the control room were alert and performed their assigned duties in a professional manner throughout the period of observation.

A significant number of work activities reaching the control room for approval had not received sufficient preparation in the work control center. The number of poorly planned work activities reaching the control room created excessive, unnecessary challenges to the operators in maintaining good control of plant configuration and status.

O1.3 Operator Attentiveness to Duty and Panel Monitoring

a. Inspection Scope

The team reviewed procedural guidance and requirements to assess operator awareness of control board indications, awareness of equipment status, and response to annunciators.

b. Observations and Findings

b.1 Control Board Awareness

Operations Head Instruction 4017, "Control Board Monitoring," required operators to be alert and attentive to control board indications and alarms at all times. This requirement ensured that the control room operators were alert for changing critical parameters, alarms, and trends, such that resolution of an abnormal trend could be addressed before plant safety was challenged.

In general, control room operators were attentive to changes in system parameters and alarming conditions. Procedure OHI-4017, Step 4.2.4, required ROs to walk down all control room panels every 60 minutes. Although the team observed the operators closely monitoring the residual heat removal system (RHR), chemical volume control system (CVCS), and reactor coolant system (RCS) parameters, operators did not consistently perform hourly panel walkdowns. As discussed in Section O 1.2, a high level of work activities, combined with system restorations from the extended shutdown, challenged the operating crew. The team observed several examples of poor operator control panel awareness associated with ongoing work activities and abnormal system configurations. These examples included the following:

- Operators fail to promptly identify loss of steam generator (SG) level indication.

  On May 9, 2000, operators tagged out a portion of the 120 volt vital instrumentation distribution circuit, which resulted in loss of power to the Number 21 and 24 SG wide range level indication. Although the operating crew had anticipated the loss of other control room indications associated with this work activity, the crew had not identified the loss of the SG wide range level indications. This condition was not identified until approximately 5 hours after the clearance was hung. This was an example of poor operator awareness in that the operators failed to anticipate or promptly identify an unexpected condition associated with a planned maintenance activity.

- Electrical bus inadvertently loaded to maximum procedural limit.

  To support maintenance activities, on May 10, 2000, the operating crew cross-connected the 21A and 21C 600 Volt alternating current (Vac) busses. Procedure OHI 4021.082.003, "Feeding 600 Volt Busses Through Tie Breakers," limited the combined loading of cross-tied busses to less than 225 amperes. On May 11, 2000, the operating crew started the south screen wash pump but did not verify that Bus 21A loading was less than 225 amperes after the pump start. Approximately 1 hour after starting the screen wash pump, an RO taking routine log readings noted that the loading on Bus 21A was approximately 225 amperes.

Once the high loading condition was identified, the operating crew took prompt action to lower bus loading. The failure to check bus loading following the start of a large electrical load with an abnormal electrical bus configuration was a poor operating practice.

- Failure to anticipate pressure transient after RCP start.

  On May 10, 2000, the operators started the Number 23 RCP with the loop four pressurizer spray valve fully open. The operators failed to anticipate the rapid pressure reduction caused by the increased pressurizer spray flow. Pressure decreased below the control band but remained above procedural limits. Once the operators recognized the decreasing RCS pressure, they took prompt and effective corrective action.

- Potential for RCS dilution, due to low setting for boric acid flowrate to blender.

  The team identified that the boric acid flow rate to the boric acid blender was set too low for current RCS conditions with the reactor coolant makeup blend control mode select switch in the automatic position. The boric acid flow rate was set for 30 gpm; however, with the current reactor coolant system (RCS) boron concentration, Procedure 12-OHP 4021.005.001, “Boron Makeup System Operation,” Step 4.1.1 required a flow rate of approximately 40 gpm. Setting the boric acid flow rate lower than required could have resulted in an unplanned boron dilution if the system provided automatic makeup to the volume control tank (VCT). Fortuitously, the licensee later determined that, the system makeup blend control switch was in the off position and automatic makeup to the VCT would not have occurred. The team noted that the 30 gpm setting provided a flow rate commensurate with a boron concentration approximately 500 parts per million boron less than RCS concentration, but above shutdown margin requirements.

  Technical Specification 6.8.1 requires, in part, that written procedures shall be established, implemented and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33, “Quality Assurance Program Requirements (Operation),” Revision 2, February 1978, Appendix A, recommended, in part, that procedures be written to cover operation of the chemical and volume control system. Procedure 12-OHP 4021.005.001 addressed requirements for operation of the boric acid flow controller. Step 3.9 of 12-OHP 4021.005.001 required the boron makeup system to be either: (1) in off, or (2) in automatic and set for the current reactor coolant system boron concentration. Steps 4.2.16, 4.3.13, 4.4.14, 4.5.15, and 4.6.15 of 12-OHP 4021.005.001 required the reactor coolant makeup blend control mode select switch to be in the off position if automatic makeup was not required. Contrary to the above, on May 11, 2000, the team identified the boric acid flow controller was set below reactor coolant system boron concentration with the makeup blend control mode select switch in auto. Failure to follow plant Procedure 12-OHP 4021.005.001 requirements was a Violation of Technical Specification 6.8.1. This Severity Level IV Violation is being treated as a Non-Cited Violation (50-316/2000003-01), consistent with Section VI.A.1 of the NRC Enforcement

Policy. This issue was documented in the licensee's corrective action program as CR 00-6837.

b.2 Equipment Status Awareness

The team observed watch turnover briefings, pre-job briefings, and questioned operators about equipment status. Watch turnovers were thorough and included a discussion of equipment status changes, abnormal configurations, and upcoming work activities. Operators performed detailed control panel walkdowns during turnovers and discussed alarm status. Operator awareness to equipment status was also evident during the conduct of shift turnover and pre-job briefs. With the exception of the control panel weaknesses discussed above, the operators were familiar with equipment status and knowledgeable about abnormal plant configurations.

Despite a number of poorly planned work activities arriving in the control room, discussed in Section O.1.2, the operators generally maintained good control of plant configuration and work activities. The US effectively screened incoming work activities and ensured that planned work and testing was compatible with other ongoing activities.

b.3 Annunciator Response

The team interviewed operators about causes for several standing alarms on the control room panels to evaluate the operators' awareness of abnormal conditions. During the team's observations in the control room, numerous annunciators were in the alarmed condition as a result of ongoing maintenance, testing, or equipment being out-of-service. The operators were knowledgeable about the causes of the alarms and required alarm responses.

c. Conclusions

In general, the team observed control room shift personnel attentive to assigned duties. Operators responded to annunciators and alarms in accordance with applicable standards and procedures and were generally knowledgeable about equipment status. Although operators frequently monitored significant plant parameters associated with the reactor coolant and residual heat removal systems, the team identified a weakness in control board awareness relating to abnormal system configurations and ongoing work activities.

The team identified that the boric acid flow rate was set too low for the existing RCS boron concentration, which was considered a Non-Cited Violation of TS 6.8.1. Setting the boric acid flow rate lower than required could have resulted in an unplanned boron dilution. Fortuitously, the system makeup blend control switch was in the off position, such that automatic system makeup flow (unplanned boron dilution) would not have occurred.

O1.4 Shift Manning and Shift Turnovers

a. Inspection Scope

The team evaluated control room shift manning and shift turnovers during the 72-hour continuous control room observation period to determine whether performance in these areas was sufficient to support unit restart.

b. Observations and Findings

b.1 Shift Manning

Shift manning consistently exceeded the levels required by TS 6.2.2. In addition to the shift manager (SM) (a senior reactor operator (SRO)), 1 RO, and non-licensed operator required by TS, a second SRO (Unit Supervisor), a second RO (balance of plant RO), and a shift technical advisor (STA) were assigned to each shift. Typically, 1 to 3 additional ROs were staffed in the control room to support testing or system restoration activities. The large volume of work requests processed through the control room placed a heavy administrative and configuration control burden on the control room staff. The additional SRO and RO staffing, beyond that required by TS, enabled the shift to safely accommodate the large work load. The team determined that the US properly controlled work authorization as necessary to ensure plant safety barriers were not jeopardized.

b.2 Shift Turnovers

Shift turnovers were thorough. Each oncoming watchstander conducted a detailed control board walkdown, log review, and verbal turnover with the off-going watchstander. Dual Unit pre-turnover crew briefings were generally detailed and included discussions of important planned evolutions and associated plant configurations for the upcoming shift. Each on-coming watchstander stated plant conditions/evolutions affecting his watch station. Mid-shift status briefings clearly discussed changes to the plant's safety function status and upcoming work activities. Minor distractions, due to ongoing test evolutions, were noted during some mid-shift control room status briefings. These distractions did not result in any unsafe plant conditions.

c. Conclusions

Control room shift staffing met TS requirements and was sufficient to support safe plant operation. Shift turnovers were conducted professionally, clearly conveying status changes for important plant equipment, and addressing planned/ongoing evolutions.

O1.5 Non-Licensed Operator (NLO) Tours

a. Inspection Scope

The team assessed the conduct and adequacy of NLO rounds by accompanying operators during the performance of their assigned duties. Two Unit 2 auxiliary equipment operators and one balance of plant operator were accompanied during containment, auxiliary building, and turbine building tours. The NLOs accompanied were from three different control room crews.

b. Observations and Findings

Non-licensed operators accompanied by the team displayed good ownership of plant equipment, pursued questions to resolution, and adequately monitored running pumps and equipment during rounds. Communications with control room staff and other departments were adequate and formal. Good foreign materiel exclusion controls were practiced during spent fuel pool tours. While several NLOs interviewed typically worked more than 60 hours per week, none exceeded the 72-hour administrative limit. Examples of good watchstanding practices observed by the team included:

- On May 9, 2000, the NLO observed plant laborers cleaning equipment associated with the Unit 2 west CCW pump. The components were associated with the running train of core decay heat removal and were posted as protected/guarded equipment requiring SM approval for work. The NLO stopped the cleaning activities and contacted the control room. The event represented a lack of work control associated with protected/guarded equipment. The event was entered in the licensee's corrective action program as CR 00-06686.

- On May 10, 2000, the NLO noticed that an extension ladder had been taken from its normal storage location and was being used to gain access to the overhead in the vicinity of the Unit 2 east CCW heat exchanger. The ladder was labeled as 'Operations Emergency Use Only' and had recently been placed in the plant with tamper-proof seals to prevent use by unauthorized personnel. The NLO reported the misplaced ladder to the control room and subsequently wrote CR 00-06780 to enter the event into the corrective action program.

The team reviewed the log recording sheets used by the NLOs and noted that they contained little detail concerning expected temperature, pressure, and flow parameters for operating equipment. Rather, the log recording sheets contained checks for having been in particular spaces and completed a general inspection of running and important equipment. Reference pages of the Operations Plant Tour Procedure, 02-OHP 5030.001.001, contained the expected system parameters. However, this additional information was not normally carried by NLOs during rounds. The team discussed this observation with the Assistant Operations Manager and were informed that a revision to the operations tour procedure was due to be completed prior to plant restart.

During the rounds the team noted two instances of NLO lack of attention-to-detail concerning changing plant conditions. On May 9, 2000, the team noticed that the Unit 2 normal SG blowdown flash tank, TK-99, contained 15 inch mercury vacuum. Investigation by the on-shift crew determined that a flash tank vent valve to the condenser, 2-BD-130, was leaking past the closed seat causing a vacuum to be pulled on the flash tank. Since the condenser had been at a full vacuum for approximately two days, at least three NLO tours had the opportunity to notice the unexpected vacuum in the flash tank prior to the team observation. Following the observation, deficiency tags were placed on the flash tank vent valve to the condenser.

In the second instance, the team noticed that the Unit 2 West and East RHR suction pressure gages were over-ranged. The suction pressure gages had a 0 to 60 pounds per square inch gage (psig) range and RHR system pressure was approximately 340 psig. The West RHR pump was a guarded/protected train for core decay heat removal at the time of the observation. The West RHR pump suction pressure gage

represented an important local parameter available to the NLO in evaluating the condition of the operating RHR pump. The gage, with its narrow range and isolated configuration provided no useful information to the NLO conducting the round. The plant pressure had been at 340 psig for several days at the time of the team observation and several NLO's had the opportunity to notice and report the over-ranged gages. Following the team observation, deficiency tags were placed on both RHR pump suction pressure gages.

c. Conclusions

Non-licensed operators used formal communications and displayed good ownership of problems and challenges occurring in their assigned areas. However, increased attention to changing plant conditions was needed, as evidenced by indications of unexpected vacuum in a SG blowdown flashtank and an over-ranged RHR pump suction pressure gage that were not identified by the operators. Overall, NLOs were capable of adequately performing their required duties.

O1.6 (Closed) Restart Action Matrix (RAM) Item C.3.3.e, Assessment of Plant Staff Performance During Restart and Sustained Control Room Observations

The team performed extensive assessments of plant performance during this inspection, including a 72-hour period of continuous control room observations as discussed in Section O1.1 through O1.5. Based on these control room observations, the team determined that RAM Item C.3.3.e, Assessment of Plant Staff Performance During Restart and Sustained Control Room Observations was closed.

O2 Operational Status of Facilities and Equipment

O2.1 (Open) Unit 2 Systems and Containment Readiness Assessments (CSC Item 13/13B)

a. Inspection Scope

The NRC previously identified CSC Item 13, regarding the performance of systems and containment readiness, as an issue requiring resolution prior to restart. In order to assess these performance areas, the team reviewed RAP 13 "Systems and Containment Readiness," Unit 2 final system readiness review reports, system readiness affirmation reports, observed system readiness review board meetings, performed extensive system walkdowns, and interviewed several system managers and reviewed training records. The systems reviewed included the CCW, ESW, RHR shutdown cooling, Emergency Diesel Generator (EDG), 120 Vac, and 250 Vdc systems.

b. Observations and Findings

b.1 System Engineering Personnel Readiness

The team interviewed the licensee's system engineering manager, nuclear steam supply system supervisor, and several system managers in order to assess their knowledge base and their involvement in the Expanded System Readiness Review (ESRR) process. The individuals were knowledgeable with prior industry system readiness review experience. The system managers clearly understood the system's design and

license bases and demonstrated an overall good understanding of the system readiness review process.

The team reviewed the system engineering training requirements outlined in procedure PMP-7200.RST.004 “Expanded System Readiness Review Program.” The required training for designated system managers included human error reduction, system design and license bases, operability determination, and 10 CFR 50.59 training. Training lesson plans were reviewed and considered comprehensive.

b.2 Restart Action Plan for Systems and Containment Readiness Assessments

In order to address CSC 13, the licensee developed RAP 13. This RAP listed 17 action items focusing on system manager training and the system readiness review milestones as described in Procedure PMP 7200.RST.004 “Expanded System Readiness Review Program.” At the conclusion of this inspection period, the team verified that 13 out of 17 action items were completed. The remaining 4 action items were associated with final system readiness reviews and system affirmations which were continuing. Overall, the RAP was detailed and comprehensively addressed NRC concerns related to system and containment readiness. The completion of all 17 action items was scheduled to occur prior to Unit 2 restart.

b.3 System Readiness Review Board (SRRB) Effectiveness

The team observed portions of final expanded system readiness review presentations by system managers to the SRRB. On May 9, the team observed the containment system manager present the containment system readiness review report to the SRRB. The system manager presented the current status of previously identified significant issues and the results of a multi-disciplinary system walkdown. The system manager was knowledgeable and effective in communicating the system readiness report findings to the SRRB. The SRRB was observed to be probing in their review of the systems’ readiness presentation. The containment system’s readiness was initially considered not ready for restart by the SRRB due to many unresolved open issues. Most of the issues involved a lack of detailed information written in the report concerning open significant issues. The team considered the SRRB decision making process to be conservative with a proper focus on nuclear safety.

b.4 Limited Effectiveness of ESRR Walkdowns

The team performed extensive system walkdowns of the CCW, ESW, EDG, shutdown cooling RHR, 250 Vdc, 120 Vac, and the containment building. The physical condition of the systems and containment building was good with visible improvements noted in the form of design changes, coatings, pipe hanger and supports, valve packing gland leakage, pump seal leakages, and wire insulation integrity. In general, there was large amount of outage related equipment throughout the auxiliary building and containment. The equipment included ladders, scaffolding, temporary lighting, temporary power, temporary ventilation, welding equipment, and other equipment required to be removed prior to plant restart.

The team identified a number of conditions adverse to quality not previously identified by the licensee. The licensee promptly entered these items in their corrective action program. These items were of minor risk significance, and some were identified on

systems not yet affirmed by the licensee; however, the team determined that the licensee's final readiness walkdowns under the ESRR process had failed to identify these issues. These examples and the additional examples discussed in Sections O2.1.b.6 and Section E.8.3 indicated that the ESRR walkdown process was not fully effective in restoration of system materiel condition. Representative examples included the following:

CR 00-06898, Bending (kinks) in RCP Number 24 oil collection system tygon tubing due to incorrect installation.

CR 00-06870, Broken conduit on CCW containment isolation valve MOV 2-CCM-430.

CR 00-06829, Floor drains under RHR recirculation sump valve enclosures were blocked with a plastic covering.

CR 00-70138, Local valve position dial indicators for 2WMO-734 and 2WMO-738, reading 100 percent open when valves are actually shut.

CR 00-06707, Potential for SI pump bearing damage due to boron crystals blocking the SI pump seal leak-off drain path.

CR 00-07180, The corrosion and boric acid control programs did not provide standards for proper control of leachable chlorides and fluorides due to wetted insulation.

CR 00-06750, Several examples of unsecured valve chain operators which could challenge safety-related instruments during a seismic event.

CR 00-06886, Cable tray penetration is missing section of fire penetration seal.

Based on the results of the team's findings, the licensee developed an action plan to perform additional area walkdowns to ensure that equipment and plant conditions were in a condition to support restart and safe plant operation.

b.5 Detailed Expanded System Readiness Reviews

The team reviewed Procedure PMP-7200.RST.004 "Expanded System Readiness Review Program" which described a detailed process for ensuring system readiness. The team also reviewed completed Unit 2 final system readiness review reports for risk significant systems including ESW, EDG, 250 Vdc, 120 Vac, and RHR shutdown cooling. The reports had been approved by the SRRB and included a detailed summary of all significant issues required for plant restart. The report details were extensive and included a complete listing of all significant items including the status of their required resolution. At the conclusion of this inspection period, 49 out of 86 systems had been affirmed as ready for restart. However, because of the number of systems which remained to be affirmed and returned to an unrestricted operational status, CSC Item 13 remained open.

b.6 Containment Readiness and Walkdown Inspections

The team performed several walkdowns of the containment areas including the upper, lower, and ice condenser compartments. Overall, the materiel condition of the containment systems, structures, and components was good. The team identified several examples of minor maintenance and housekeeping issues, but recognized that the work in containment had not been completed and several final walkdowns by the licensee were yet to be performed. The team identified two spring can supports that appear to be outside the specified settings. The first issue involved one of two supports for all the incore detector guide thimbles. The second spring can support (2-GCTS-V696) was associated with the containment spray system. Both issues were entered into the licensee's corrective action program. Preliminary reviews performed by the licensee determined that no immediate operability concerns existed.

c. Conclusions

A detailed readiness review process had been conducted on plant systems to ensure system readiness in support of plant startup and power operation. The system managers clearly understood the system's design and license bases and demonstrated a good overall understanding of the system readiness review process. Further, the System Readiness Review Board was effective in reviewing and probing system manager readiness reports with a clear focus on reactor plant safety.

Overall, the licensee's system walkdowns were adequate in identifying system conditions adverse to quality. However, the team identified a number of material condition issues not previously identified by the licensee during the system walkdowns. The licensee's corrective actions included additional area walkdowns to identify materiel condition issues prior to restart.

Because of the number of plant systems which had not yet been affirmed and restored to an operational status, CSC Item 13 associated with Systems and Containment Readiness, remained open at the conclusion of the inspection.

O2.2 Unit 1 Equipment Required for Unit 2 Safe Shutdown

a. Inspection Scope

The team evaluated the effectiveness of the process for controlling the status of the Unit 1 equipment required for the safe operation and shutdown of Unit 2.

b. Observations and Findings

The team noted that Procedure 01-OHP 4030.066.4025 "Unit One Appendix R Requirements for Unit 2," provided a controlled framework with multiple layers of supervisory verification of equipment status. This procedure was implemented by 02-OHP 4021.001.001, "Plant Heatup From Cold Shutdown to Hot Standby." Awareness of the Unit 1 guarded equipment required for the safe shutdown of Unit 2 was established through discussion at the morning planning meetings, as part of the "Plan of the Day," during shift turnovers, and through postings using pink signs or caution tags. Additionally, work on sensitive equipment was to be screened and assessed by a SRO in the work assessment phase and prior to work release.

The team was informed that procedures which governed the work management activity scheduling process were also being revised to give specific guidance on how to deal with critical maintenance projects, in the outage unit, which would place the on-line unit in a Limiting Condition for Operation. For example, TS required that for the CVCS, ESW, Auxiliary Feedwater (AFW), and CCW systems, at least one flow path from each of the systems be "available" to support the opposite unit's shutdown function. Procedure 01-OHP 4030.066.4025 defined the term "Available" and included a list of Unit 1 components, for each system, which constituted an available flowpath for supporting a Unit 2 safe shutdown.

c. Conclusions

The licensee had developed and implemented a well defined and controlled process for ensuring the availability of Unit 1 equipment required for safe shutdown of Unit 2.

O2.3 (Open) RAM Item C.4.a, Operability of TS Systems

a. Inspection Scope (93802)

The team reviewed the current status of TS required systems as well as the licensee's programmatic controls for affirming systems ready for restart.

b. Observations and Findings

As defined in Procedure PMP 7200.RST.004, "Expanded System Readiness Review Program," the licensee had identified 86 Level I and II functional systems to be reviewed and affirmed as ready for restart. The TS required systems were classified as Level I systems. At the end of the inspection, the licensee had affirmed 8 of 21 Level I systems as ready for restart under the guidelines in PMP.7200.RST.010 "Functional Area Restart Readiness." As discussed in Section O2.1, the team performed system walkdowns and evaluated the operational status of various systems. From those reviews, the team determined that the licensee had established system readiness and the systems met TS operability requirements. The team found the licensee's process to review and affirm systems' readiness for restart to be detailed and comprehensive with multiple levels of management review. Further, the team did not identify any concerns with the status of the system surveillance tests or operability of the systems reviewed. However, with 13 Level I systems still remaining to be affirmed as ready for restart by the licensee, the team did not consider RAM Item C.4.a, Operability of TS Systems, ready for closure.

c. Conclusions

The process to review and affirm systems as ready for restart was detailed and produced acceptable system status. For the systems reviewed by the team, the licensee had adequately returned the systems to service. However, a number of systems remained to be affirmed and therefore, RAM Item C.4.a, Operability of TS Systems remained open.

O2.4 (Closed) RAM Item C.4.b, Operability of Required Secondary and Support Systems

a. Inspection Scope

The team reviewed the current status of several secondary plant systems as well as the licensee's programmatic controls for developing System Test Plans (STP) and verifying successful STP completion for system turnover. The team also reviewed the Startup and Power Ascension Plan to determine whether appropriate controls were in place to ensure secondary systems would be operable prior to the mode of plant operation for which the individual system was required for safe plant operation.

b. Observations and Findings

The team reviewed secondary system readiness with the balance of plant engineering supervisor. For secondary plant systems, 15 of 23 had been turned over to operations and 13 of 23 systems had been affirmed as ready to support unit restart. The team reviewed PMP-7200.RST.002 "Start-Up and Power Ascension" and determined that appropriate individual secondary system readiness requirements were specified for the various plant mode hold milestones (i.e., Mode 4, Mode 3, Mode 2, etc.). Additionally, PMP-7200.RST.004 "Expanded System Readiness Review Program," contained comprehensive instruction for system readiness affirmations.

Procedure PMP-7200.RST.005 "Restart and Power Ascension Testing Program" provided detailed instruction for developing, tracking, and verifying completion of individual STPs. The team reviewed STPs for the following systems: auxiliary steam, main steam, ESW, non-essential service water, and control air. These STPs contained appropriate test requirements to demonstrate system operability following the maintenance and modification activities performed during the extended plant shutdown. The team noted minor discrepancies in that several STPs did not address post modification testing requirements in Table 4, "Restart and Power Ascension Testing." Condition Report 00-07140 was initiated to address this deficiency. The team determined that post modification test requirements were adequately addressed elsewhere in the STPs or plant modification documents.

The team questioned engineers regarding whether the secondary system reviews had addressed several recent industry events which had the potential to cause plant transients or cause safety systems to fail. System engineers were aware of the industry events and actions had been taken when deemed appropriate. The team noted one exception where the potential for an ESW strainer vent failure to cause a water hammer pressure event had not been fully evaluated. Engineers initiated CR 00-07150 to address this issue. Overall, the team determined that engineers had effectively integrated industry experience into the secondary system readiness affirmation process.

c. Conclusions

The startup and power ascension plan specified appropriate individual secondary system readiness requirements for the various plant mode-hold milestones. System test plans contained appropriate test requirements to demonstrate system operability following the maintenance and modification activities performed during the extended plant shutdown. Engineers effectively integrated industry experience into the secondary system readiness affirmation process. The licensee had affirmed 13 of 23 systems and

had reasonable controls in place, to ensure readiness affirmation of the remaining systems before restart. Based on the results of this review, RAM Item C.4.b, Operability of Required Secondary and Support Systems, was closed.

O2.5 (Open) RAM Item C.4.c, Results of Pre-startup Testing

a. Inspection Scope

The team reviewed the programmatic controls established for system operational testing and several individual STPs to assess the pre-startup test program.

b. Observations and Findings

The team considered that PMP-7200.RST.004 “Expanded System Readiness Review Program” and PMP-7200.RST.005 “Restart and Power Ascension Testing Program” provided comprehensive instruction, programmatic controls, and reviews to verify system readiness. The team reviewed the EDG, 120 Vac, and 250 Vdc STPs in addition to the five secondary system STPs discussed in Section O2.4. These STPs contained appropriate test requirements. Specific plant mode constraints or test conditions were properly identified and tracked. The team concluded that pre-startup system testing was properly identified, controlled, and being performed to support system operability. However, a large amount pre-startup testing was not yet complete and therefore, RAM Item C.4.c, Results of Pre-startup Testing remained open.

c. Conclusions

Pre-startup system testing was properly identified, controlled, and being performed to support system operability and turnover. However, a large amount pre-startup testing was not yet complete and therefore, RAM Item C.4.c, Results of Pre-startup Testing remained open.

O2.6 (Open) RAM Item C.4.d, Adequacy of System Lineups

a. Inspection Scope

The team performed system walk-downs for selected systems based on their risk, safety significance, and operational status at the time of the inspection. Inspection attributes included equipment materiel condition, proper valve and switch positioning, and equipment labeling. Documents reviewed included system operating procedures, system flow diagrams, abnormal valve lineup logs, and control room operator workaround logs.

b. Observations and Findings

The team verified system lineup checks during the walkdowns on the CCW, EDG, ESW, shutdown cooling RHR, 250 Vdc, and 120 Vac systems and confirmed that the selected systems were properly aligned and capable of performing their design function for the current mode of operation. Specifically, the systems inspected were properly aligned and controlled by operations and components were properly labeled. However, a number of system remained to be affirmed and system lineups established prior to restart. Therefore, RAM Item C.4.d, Adequacy of System Lineups remained open.

c. Conclusions

The team reviewed system lineups of six safety-related systems and confirmed that they were properly aligned and capable of performing their design function in the current mode of operation. However, a number of systems remained to be affirmed and system lineups established prior to restart. Therefore, RAM Item C.4.d, Adequacy of System Lineups remained open.

O3 Operations Procedures and Documentation

O3.1 Procedures and Procedural Usage

a. Inspection Scope

The team observed control room operators using procedures, conducted interviews, reviewed selected operating procedures, and reviewed the operating procedure change backlog to determine whether procedure quality and usage was sufficient to support safe plant restart.

b. Observations and Findings

The team observed various plant evolutions including realignment of RHR cooling, SG sparging and fill, RCS check valve leak rate testing, RCP operation, RCS boration, CCW system operation, and response to various control room annunciators. Generally, procedure instructions were complete and appropriate for the specified activity. Procedure deficiencies which led to an unexpected plant response or unsuccessful test result included 2-IHP 4030.STP.226 “RCS Valve Leak Rate Test” and O2-OHP 4021.002.003 “RCP Operation.” In each case operators initiated a CR to correct the procedure deficiency. Further, pre-evolution briefings, communications during operations and maintenance/testing activities, procedure use, and peer checking were consistently performed in accordance with OHI-4000 “Conduct of Operations: Standards” and OHI-2000 “Operations Department Guidance Policy.”

The team noted that 81 operating procedures were on hold, pending revision prior to Unit 2 startup. The specific deficiencies and mode hold constraints associated with each procedure were clearly identified and tracked in the System Information Data Base System (SIDS) and on the appropriate Official Mode Hold List which required management review in accordance with PMP-7200.RST.002 “Startup and Power Ascension,” prior to each mode change. The team reviewed the procedure change backlog with the operating procedures upgrade program manager. Based on these reviews, the team determined that appropriate controls were in place to ensure that the required operating procedure revisions were approved and implemented prior to the plant operating mode at which they were needed. The licensee had also implemented an emergency operating procedure (EOP) upgrade project during the extended plant outage. The revised EOPs were approved and operators had received training on the EOPs. Two design changes remained to be completed prior to validating and fully implementing the revised EOPs. The team considered that appropriate controls were in place for implementing the revised EOPs.

The team reviewed a sample of 28 plant operating procedures which the licensee considered ready to support plant restart. The team determined that the selected

procedures provided adequate instruction for operators to safely conduct plant restart. However, the team noted that biennial procedure reviews had not been performed for 68 operating procedures currently issued for use during plant restart. Licensee representatives initiated CR 00-6992 to document this condition. The licensee's extent of scope investigation also found 1 engineering, 1 performance assurance, and 12 radiological procedures overdue, documented in CR 00-7058, CR 00-7066, and CR 00-7092. The team reviewed the recovery plan documented in these CRs and had no further questions. The licensee planned to revise Unit 2, Unit 12 (common), and Unit 1 procedures, required to support Unit 2 operations, before entering Mode 4 for Unit 2.

Technical Specification 6.8.1 requires, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide (RG) 1.33, "Quality Assurance Program Requirements (Operation),"Revision 2, February 1978. Appendix A of Regulatory Guide 1.33 recommended, in part, that procedures be written to cover procedure review and approval. Step 3.7 of PMP 2010.PRC.002, "Procedure Correction, Change, and Review," Revision 5, requires each department to perform a periodic review on all procedures covered by this program every 2 years. Contrary to these requirements, the licensee failed to perform periodic reviews within a 2-year frequency for 68 procedures as required by Procedure PMP 2010.PRC.002 which is a Violation of TS 6.8.1. This Severity Level IV violation is being treated as an Non-Cited Violation (50-316/2000003-02), consistent with Section VI.A.1 of the NRC Enforcement Policy. This issue was captured in the licensee's corrective action program in CR 00-7066, CR 00-6992, CR 00-7058, and CR 00-7092.

c. Conclusions

The team considered the surveillance test and operating procedure instructions adequate and procedure use good, including pre-evolution briefings, communications, and peer-checking. For procedure deficiencies which led to an unexpected plant response or unsuccessful test result, the licensee implemented appropriate corrective actions. Overall procedure quality was considered adequate for the operators to safely restart Unit 2.

Eighty-one operating procedures were on hold, pending revision prior to Unit 2 startup. Appropriate controls were in place to ensure required operating procedure revisions were approved and implemented prior to the plant operating mode at which they were needed. One Non-Cited Violation of TS 6.8.1 was identified regarding the failure to perform biennial reviews for active procedures.

O3.2 Operations Drawing Control

a. Inspection Scope

The team reviewed drawing controls and the adequacy of selected drawings available to operators in the Unit 2 control room and the SM office.

b. Observations and Findings

The team noted that adequate procedure guidance existed to ensure control of the plant drawings available to the operating crew and to ensure that the drawings reflected current plant configurations. For those systems with active design changes, a separate tracking system was available to control room operators which referenced the specific design change package and associated work requests for interim system configurations. Aperture cards were available to the Unit 2 control room staff to reference system drawings and configurations. The drawings available to the operating crew included selected flow, wiring, and logic diagrams. The team reviewed the selection of drawings available to the operators and determined that the selection covered important systems and functions and was adequate to support Unit 2 restart. The team sampled and viewed a number of the aperture cards across a range of systems in both the Unit 2 control room and the SM's office. All were stamped as controlled documents with the correct, controlled revision. The team sampled selected hard copied drawings and noted that all were properly controlled with the most current revision available to the operators.

The team sampled two active design change packages and noted that adequate interim drawing controls were in effect. The team sampled drawings associated with temporary modifications. With one exception, temporary modification tags were correctly attached to aperture cards informing the operators of an active temporary modification on the associated system. The team noted that although temporary modification 2-99-07 had been completed and removed from the Unit 2 refueling water storage tank to coolant charging pump suction valves, 2-IMO-910 and 911, a tag associated with the modification was still attached to the associated aperture card, OP-2-98273, in the Unit 2 control room. The STA pursued the team's observation and determined that the temporary modification had been correctly removed but that an administrative error had occurred in not removing the tag from the associated aperture card in the control room. While not safety significant, the error highlighted the confusion concerning equipment/drawing status that could occur when temporary modifications records were not completely cleared from controlled drawings.

c. Conclusions

Adequate controls for plant drawings were in effect, to ensure that the operating crews had accurate drawings which reflected the current plant configuration.

O3.3 (Open) RAM Item C.4.g, Adequacy of the Power Ascension Testing Program

a. Inspection Scope

The team conducted interviews and reviewed various documents to determine whether the Startup and Power Ascension Plan included appropriate activities and instructions to support a safe plant restart.

b. Observations and Findings

Procedure PMP-7200.RST.002, "Startup and Power Ascension" contained comprehensive reviews, verifications, and requirements for plant readiness for restart. Specific requirements were clearly identified for each of ten plant mode holds (Mode 6,

Mode 5, bumping RCPs, establishing condenser vacuum, Mode 4, Mode 3, Mode 2, Mode 1, 50 percent reactor power, and 90 percent reactor power). Appropriate levels of management review and approval were required for each individual mode hold. Reasonable controls were established to ensure lessons learned from the Unit 2 restart were documented and tracked for management review and integration into the Unit 1 restart. At the close of this inspection approximately 1500 items remained open, to be completed prior to Unit 2 entering mode 4 conditions.

The team discussed the Power Ascension Schedule with the SRO assigned responsibility to verify the schedule. The schedule was not ready for verification at the close of the inspection. The existing schedule was a template of previous plant startups. However, numerous operating procedures were not sufficiently revised to support plant restart and numerous system turnovers had not been conducted. Each of these items had the potential to generate additional testing or operational activities which would require integration into the Power Ascension Schedule. The team determined that the Power Ascension Schedule was not sufficiently developed and reviewed at the close of the inspection to support plant restart. Therefore, RAM Item C.4.g, Adequacy of the Power Ascension Testing Program remained open.

c. Conclusions

The Startup and Power Ascension Plan contained comprehensive test requirements, reviews, and verifications to ensure plant readiness for restart. Appropriate controls were established to ensure lessons learned from the Unit 2 restart were documented and tracked for management review and integration into the Unit 1 restart plan. However, the Power Ascension Schedule was not sufficiently developed and reviewed at the close of the inspection to support plant restart. Therefore, RAM Item C.4.g, Adequacy of the Power Ascension Testing Program remained open.

O5 Operator Training and Qualification

O5.1 (Closed) RAM Item C.3.3.d, Effectiveness of restart simulator/required training necessary to re-familiarize personnel with operating conditions

a. Inspection Scope

The team performed assessments to evaluate operators knowledge of significant system modifications implemented during the extended outage and to verify that the operators have been adequately trained to successfully operate the modified systems. The team reviewed applicable documents and interviewed licensed and non-licensed operations staff.

b. Observations and Findings

As documented in Inspection Report 50-315; 50-316/2000009, the NRC performed a review of recent plant modifications for proper incorporation of operator training. The licensee's training department was involved in maintaining control and coordination of recent plant modifications requiring training, or affecting the configuration of the simulator.

During this inspection, the team assessed operator knowledge of overall plant and systems readiness by conducting interviews with operations personnel. As discussed in Section O 3.1, the team observed that the licensee had also implemented an emergency operating procedure (EOP) upgrade project during the extended plant outage and operators had received training on the EOPs. At the time of the inspection, two design changes remained to be completed prior to validating and fully implementing the revised EOPs. The team considered that appropriate controls were in place for implementing the revised EOPs.

As discussed in Section O 8.1, the team reviewed the licensee's programmatic readiness review project developed to identify and correct programmatic problems station wide. Procedure "Programmatic Restart Readiness" was a detailed and comprehensive document for verifying readiness of important station programs. Ninety-four of 125 programs received detailed reviews and assessments based on their potential impact on safe plant operation. The baseline assessments and program affirmations were complete for various programs including operator training.

c. Conclusions

The licensee conducted operator training at an acceptable level to provide operators with the knowledge necessary to operate systems modified during the Unit 2 outage. The team determined that RAM Item C.3.3.d, Effectiveness of restart simulator/required training necessary to re-familiarize personnel with operating conditions, was closed.

O7 Quality Assurance in Operations

O7.1 Operations Department Performance Assurance Audits and Self-Assessments

a. Inspection Scope

The team reviewed resolution of findings and conclusions for Performance Assurance (PA) departments assessments associated with the operations department. The team assessed the effectiveness in resolution of the associated findings and the ability to develop long term operational objectives/plans were assessed. Additionally, effectiveness of the PA organization's involvement in tracking and resolution of identified issues was evaluated.

b. Observations and Findings

The team reviewed the operations department self-assessment (SA) schedule and noted that assessments focused on appropriate areas challenging plant operations including operator workarounds, operability determinations, progress in addressing Operations Leadership Plan issues, annunciator response procedures, and procedure adherence. Self-assessments had been completed close to or on scheduled dates. Self-assessment team membership contained sufficient diversity of peers and personnel from outside the operations department to be effective. Procedures used during the conduct of operations self-assessments were adequate in describing an effective SA process. Corrective actions were generally completed by the scheduled date with few actions overdue.

The team reviewed four recent operations department SAs and found the assessments to be sufficiently critical with generally acceptable corrective actions. In two instances, however, the corrective actions prescribed in the self-assessment were not detailed in describing how recommendations for improvement of identified problems should be accomplished. For instance, SA-2000-SPS-009 on the Clearance Permit System recommended continuous training for operators on the clearance process. The finding was discussed with the operations unit and assistant managers but no details on a specific continuous training regime or schedule were developed. In the second example, SA-1999-OPS-008 identified the need for a review process to reduce the number of longstanding temporary modifications installed in the plant. No specific actions were assigned to describe the structure of the review program or how the objective of reducing the number of temporary modifications would be accomplished.

The team reviewed the Operations Leadership Plan. The plan was comprehensive, detailed, and provided good direction for operations department performance improvements. The plan contained 402 action items, 289 required for restart and 113 designated as post-restart actions. As of May 10, 2000, 15 restart action items remained open with three of the 15 overdue. All 15 of the remaining open restart action items had been assigned to pending mode changes via a separate licensee tracking system.

The team reviewed PA and operations department monthly reports. The team found that the PA reports were more critical of operations performance than the operations department reports. The PA reports provided critical insights of operations performance in the areas of configuration control, the clearance permit system, and procedural adherence, quality and usability. The operations department monthly performance reports following January 2000, contained good and innovative analysis of operations performance. In the January report, for instance, a Burden Index was introduced which related problems with procedural adherence to the number of new procedures and changes being introduced to the operating crews.

The team noted an area of disagreement in the PA and operations department monthly reports concerning field observations involving procedural adherence. Performance Assurance observations recorded procedure adherence observations that were not being similarly noted during operations department field observations. While sufficient numbers of operations field observations or ‘scorecards’ were performed, they were not being sufficiently critical in finding the same deficiencies noted by PA. The operations department took actions to address this difference in self-criticalness in January 2000, by communicating the disparity to management staff and defining specific focus area expectations concerning procedural adherence monitoring during field observations. As of April 2000, increased effort was being made to correlate PA and operations field observations although PA observations continued to be more critical then those made by the operations department.

The team reviewed four recent root cause investigation reports concerning safety evaluations, equipment clearances, configuration control and a non-essential service water event to determine if effectiveness reviews of corrective actions were occurring. For each of the four root cause reports, effectiveness reviews were defined, however, only one of the four effectiveness reviews concerning equipment clearances was scheduled for completion at the time of this inspection. The team examined the equipment clearance effectiveness review and noted that it had been completed as

scheduled. This review concluded that the corrective actions had been effective in preventing reoccurrence of the identified problems.

c. Conclusions

Performance Assurance audits were more critical of operations performance than the operations department self-assessment audits. The combined efforts of the PA and operations department, provided sufficient assessment capability to identify problems challenging operators.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Programmatic Final Readiness Reviews (CSC 14/14G)

a. Inspection Scope

Several programmatic problems were identified during NRC inspections conducted following the Unit 2 shutdown in September 1997. The licensee established a programmatic readiness review process to identify and correct programmatic problems station wide. The team conducted interviews, and reviewed selected programmatic affirmation documents to determine whether the station's programs were functioning sufficiently to support safe unit restart.

b. Observations and Findings

Procedure "Programmatic Restart Readiness" was a detailed and comprehensive document for verifying readiness of important station programs. Peer industry experience from other sites which had implemented major station restart plans was integrated into the D.C. Cook Programmatic Readiness Baseline Assessment Questionnaire. Baseline assessments were performed on 125 programs. Ninety-four of these programs received detailed reviews based on their potential impact on safe plant operation. Discrepancies identified in each program were addressed through CRs and functional area leadership plans which were required to be complete before department managers could affirm readiness for plant mode changes. Station management completed affirmation of programmatic readiness on April 12, 2000.

The team interviewed the RAP owner for Programmatic Readiness and confirmed that the baseline assessments and program affirmations were complete for the 14 programs listed below:

Final Safety Analysis Report Revalidation/Update	Operator Training
Calculations	Procedures
Operating Experience	Human Performance
Design and Licensing Basis	Surveillances
Instrument Uncertainty	10 CFR 50.59
Motor Operated Valves	Design Change Process
Corrective Action Program	Performance Assurance

Additionally, the team performed a detailed review of the Operability Determination Evaluation (ODE) and Operating Experience (OE) program affirmation records. In response to the baseline program assessment, the ODE procedure was revised to

incorporate more industry experience and several self assessments were performed. Notable improvements resulting from these self-assessments included assignment of the operations department as program owner, more timely ODEs, and improved procedural guidance. The team determined that PMP 7030.OPR.001, "Operability Determinations," was comprehensive, the self-assessments were critical and provided meaningful recommendations, and ODEs performed during this inspection indicated the program was being effectively implemented. The OE program baseline assessment was critical and resulted in several noteworthy improvements. Operating experience issues for the past 5 years were reevaluated, PMP 7030.OE.001, "Operating Experience," was revised (Revision 4), and site-side access to an industry OE website was established. The programmatic reviews and independent inspection findings during this report period (ODE, OE, engineering calculations, and self-assessments) indicate that, in general, the station's programs were functioning properly.

c. Conclusions

The licensee completed detailed reviews and affirmations for 94 plant programs. Based on a sample of program area reviews, the team considered that the station programs were functioning adequately to support restart. Therefore CSC Item 14/14G, Programmatic Final Readiness Reviews, was closed.

O8.2 (Closed) Resolution of Functional Area Final Readiness Reviews (CSC 15/15B)

a. Inspection Scope (93802)

The licensee established functional area readiness reviews to ensure that departments were in a state of readiness to support plant startup and safe operation. The team conducted interviews and reviewed selected functional area affirmation documents to determine whether the plant's departments were functioning sufficiently to support safe unit restart.

b. Observations and Findings

The functional area assessments performed by the licensee included a critical review of department staffing, training and associated qualifications, backlog reductions, establishing improvement goals, and identifying performance deficiencies.

The team determined that the licensee's assessment of departmental readiness was thorough and comprehensive. To ensure an adequate assessment was performed, standardized actions were developed that were applicable to all functional areas. These included procedure preparation for conducting functional area assessments, establishing leadership plans for departmental team leads, criteria for presenting assessments reports to the Plant Operating Review Committee, and maintaining a systematic method for the tracking and resolution of corrective actions. In addition, departmental aggregate evaluations were performed to aid in identifying generic departmental issues. The implementation of these measures was objective and comprehensive while performing functional area assessments.

The team reviewed the closure documents for Corrective Action Items 3.d and 4.a of the Closure Package for RAP 15. These items pertained to the affirmation of functional areas for restart readiness and performance of an aggregate effect evaluation on the

results of the 1999 departmental assessments. The Leadership Plan developed for the operations functional area was reviewed and noted to be similar in nature to plans used in other functional areas. The plan outlined specific problem statements in the operations functional area, the intended objectives and results, and a detailed list of required actions to ensure the objectives could be achieved. The Leadership Plan incorporated the findings and recommendations from the functional area assessment and problematic assessments and remained the controlling assessment document. The team determined that this process appeared to be an effective tool in verifying functional area readiness. In the corrective action closure documentation, the licensee concluded that no new generic issues existed which represented challenges for safe startup and operation of Unit 2.

c. Conclusions

The team concluded that the functional area assessments were sufficiently objective, comprehensive and conducted in sufficient detail, with appropriate corrective action resolution, to ensure departmental readiness in support of Unit 2 restart. Therefore, CSC Item 15/15B, Resolution of Functional Area Final Readiness Reviews, was closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments on Surveillance Testing Activities

The team inspected several surveillance activities, and observed that these activities were properly controlled and documented, the pre-job briefings were detailed and effective in preparing station personnel for performing the tests. In addition, the surveillance tests observed effectively demonstrated system operability. However, for the RHR surveillance evolution conducted on May 9, 2000, involving retesting check valves 2SI157L1 and 2SI157L4, the valves failed their leakage test. Further, the test was delayed due to the licensee's identification that the testing procedure was inadequate. Condition Report 00-06752 was initiated and a procedure change was implemented to correct the procedure inadequacies. The team considered the licensee's corrective actions to be appropriate.

M1.2 Maintenance Activities

a. Inspection Scope

The team observed a limited number of maintenance activities due to the minimal amount of risk significant work performed during the inspection period. The team reviewed and made direct observations of the following work:

JO C0053722, West Auxiliary Feed Pump Room Ventilation Rewiring
JO C0052673, EDG "CD" Starting Air Compressor Replacement
JO C0056914-01, Speed Increaser Oil Pump Replacement

b. Observations and Findings

The team confirmed that the personnel conducting the maintenance work activities were cognizant of their procedure requirements, used proper documentation and properly followed the job order requirements. These work activities had appropriate supporting administrative controls provided by the station's work control center.

c. Conclusions

Observed maintenance work was performed in accordance with approved job orders and administratively controlled by the station's work control center. The maintenance personnel were knowledgeable about the maintenance and had the required documentation at the job site.

III. Engineering

E1 Conduct of Engineering

E1.1 Plant Modifications

a. Inspection Scope

The team reviewed six safety-related modifications of plant components to evaluate engineering department performance in resolution of the condition which necessitated the modification and actions taken to ensure preservation of the system design basis. The team reviewed post modification testing for the each of the modifications selected to confirm adequate demonstration of component design functions in support of returning equipment to service.

b. Observations and Findings

b.1 Replacement of Emergency Diesel Generator Aftercoolers

The team reviewed 02 DCP-0168 "Replace EDG Aftercoolers." The licensee replaced the EDG aftercoolers to resolve degraded conditions created by corrosion over a long period of use. Identical replacement aftercoolers were not available, and the licensee installed aftercoolers of similar design and comparable weight recommended by the EDG vendor. The aftercooler was leak tested and no leakage was identified following installation. The licensee performed a post modification test run of the diesel to confirm proper operation of the aftercooler. The team considered that this modification was properly designed and installed, with appropriate post modification testing to confirm that the system design basis had been preserved.

b.2 Removal of Auto Closure Interlocks on RHR Suction Valves

The team reviewed 02 DCP-0183 "Remove Auto Closure Interlocks/RHR Suction Valves IMO-128 and ICM-129." The licensee made this change to allow power to be removed from these valves while the RHR system was in use to eliminate the possibility of an automatic isolation of the RHR system during long term cooling. The licensee identified and initiated the required changes to the Updated Final Safety Analysis Report (UFSAR)

and Sections 3.5.2 and 3.5.3 of the Technical Specifications (TS), which described the automatic isolation feature. Additionally, the licensee correctly identified the required administrative changes to calculation PS-EDGL-005, "Emergency Diesel Generator Momentary Loading." The licensee completed post modification test 21HP4030.STP.509, "Residual Heat Removal Suction Valve Interlock Bistable Functional Test," which confirmed the expected system operation. The team considered that this modification was properly designed and installed, with sufficient post modification testing to confirm that the system design basis had been preserved.

b.3 Installation of an RHR System Test Flow Loop

The team reviewed 02 DCP-4344 “Install RHR Test Flow Loop” and supporting calculations. The licensee installed the RHR test loop to resolve a concern for unmonitored leakage from the containment sump to the refueling water storage tank (RWST) during the recirculation phase of ECCS operation (Reference NRC Inspection Report (50-315/99029(DRS); 50-316/99029(DRS)). The original piping configuration would not allow adequate testing to quantify the leakage of six valves. To confirm that unmonitored leakage was less than assumed in off-site dose calculations, the licensee initiated this design change which permitted monitoring the leakage through the double disk gate valves in the RHR and containment spray systems. This modification installed test connections (tubing and isolation valve) on the valve bodies for the isolation valves between containment re-circulation water and the RWST. The licensee leak tested the modified systems and no leakage was detected. The team considered that this modification was properly designed, installed, and tested to confirm that the system design basis had been preserved.

b.4 Unit 2 CCW Heat Exchanger Inspections

The team reviewed 02 DCP-0561 “CCW Heat Exchanger (2HE-15E, 2HE-15W) Tube Plugging” and supporting calculations. Supporting calculations included determining the heat transfer characteristics under design basis accident conditions and worst case operating conditions with 5 percent (113) of the tubes plugged. Additionally, the licensee calculated the minimum design allowable tube wall thickness to provide tube inspection and plugging criteria. Inspection, cleaning, plugging and final pressure test required by this design change was performed in accordance with Procedure 12MHP5030.016.001 “Component Cooling Water Heat Exchanger Inspection, Cleaning and Tube Plugging.” Based on the inspections performed, 33 tubes in the East heat exchanger and no tubes in the West heat exchanger were plugged. During the final post modification pressure test, twelve cubic centimeters of water was collected from the outlet drain for the 2-HE-15E heat exchanger as documented in CR 99-24474. The licensee determined based on chemical testing of the water collected, that this water was condensation and not lake water. Thus, this water did not constitute leakage and the test was considered acceptable. The team considered that this modification was properly designed and installed, with sufficient calculations and post modification testing to demonstrate that the system design basis had been preserved.

b.5 Installation of ESW System Taps

The team reviewed 02 LDCP-5480 “Install ESW System Taps with Isolation Valves” and the supporting stress analysis calculation. For this design change, taps were added to the ESW system consisting of a valve, piping and pipe cap to support addition of a

cooling water supply to AFW pump room coolers installed under 02 DCP 4261. These 2 inch diameter pipe taps were located on the 4 and 6 inch diameter supply lines for AFW and the 20 inch ESW system return header. The licensee performed a stress analysis to confirm that the design basis of the ESW piping had been maintained. The licensee demonstrated the system pressure boundary integrity by performing an ASME Code VT-2 visual examination for system leakage at normal operating pressure following this modification. No leakage was identified. The team considered that this modification was properly designed and installed, with an appropriate calculation and post modification test to confirm that the system design basis had been preserved.

b.6 AFW System Modifications to Maintain Design Flow

The team reviewed 02 DCP-0667 “Modify AFW to Maintain Design Flowrate While Taking a Suction from ESW.” The licensee modified the ESW system and AFW suction strainers to resolve a concern for inadequate AFW flow caused by suction strainer plugging when aligned to the ESW system (Reference NRC Inspection Report (50-315/98017(DRS); 50-316/98017(DRS)). This modification resolved the original problem associated with rapid debris loading on the suction stainers by changing the configuration of the ESW supply piping for the west motor driven AFW pump to eliminate a debris trap and changing the suction filters to a courser mesh. The licensee identified and qualitatively evaluated the impact of the system changes on hydraulic flow resistance and pump performance. The licensee completed a VT-2 visual examination for leakage of the modified ESW piping at normal operating pressure to confirm system integrity. No leakage was identified. In addition, the licensee scheduled performance of 02-DCP-667-TP.01 “Unit 2 West MDAFP [motor driven auxiliary feedwater pump] Strainer Flow Test” to demonstrate that while in the backup ESW supply mode, the AFW system can maintain design basis flow requirements. The team reviewed the proposed test and considered that the acceptance criteria would adequately confirm system required design flow. Additionally, the licensee scheduled the performance of EHP 4030.219.001 “ESW Flow Balance” at 18-month intervals. This test performed system flushes to confirm system flows and flushed debris buildup from the lines. The team considered that this modification was properly designed, installed and appropriate post modification testing scheduled to confirm the system design basis.

c. Conclusions

The team reviewed a sample of modifications implemented during the extended shutdown. These modifications were properly designed, installed, and tested, which indicated that the modification process was functioning effectively. The supporting calculations and post modification tests demonstrated that the modifications accomplished the intended purpose and preserved the system design basis.

E1.2 Temporary Modifications

a. Inspection Scope

The team reviewed the temporary modification (TM) process, included the implementing procedure. The process was used for both safety and nonsafety-related changes and the TMs were categorized as regular temporary modifications and proceduralized temporary modifications. The review included the Temporary Modification Log Indexes, located in the control room, and four selected TM packages for both categories of TMs.

b. Observations and Findings

b.1 Regular Temporary Modifications

The team reviewed the packages for the two Unit 2 TMs and two of the TMs, applicable to both units, which were listed as installed on the Control Room Temporary Modification Log Index for regular TMs. The index listed two Unit 2 TMs and three TMs, that were applicable to both units, as installed. The TM packages for the installed TMs, including 10 CFR 50.59 screenings and evaluations were considered adequate.

The Control Room Temporary Modification Log Index for regular TMs listed six Unit 2 TMs that had not been installed, some of which had been issued for over one year. This method of logging non-installed TMs appeared to be a potential source of confusion for the operators and could have resulted in the installation of out-dated TMs. The team questioned this practice, which prompted the licensee to remove the non-installed TMs from the index. Additionally, an installed proceduralized TM was incorrectly identified as not installed on the regular TM index. The licensee subsequently documented the teams concerns in CR 00-07021 and implemented a revision to Procedure 12 EHP 5040.MOD.001, to eliminate the potentially confusing log practices. With the corrective actions taken, the team considered TMs to be adequately controlled.

b.2 Proceduralized Temporary Modifications

The team reviewed TM packages for two Unit 2 TMs and two TMs, applicable to both units, which were listed as installed on the Control Room Temporary Modification Log Index for proceduralized TMs. The index listed five Unit 2 TMs and five TMs, applicable to both units, as installed. This index also listed five TMs as having been installed and subsequently removed. The team considered the log entries for the removed proceduralized TMs another potential source of confusion for the operators. No problems were noted with the proceduralized TMs reviewed and the installed TM packages were considered adequate.

c. Conclusions

A potential source of confusion for the operators was identified in the Control Room Temporary Modification Log Index associated with approved TMs, which had not been installed. Licensee corrective actions included a procedure change and deletion of the non-installed TMs from the control room index. Based on review of the process, selected packages, and the corrective actions implemented, the overall TM process was considered adequate.

E7 Quality Assurance in Engineering Activities

E7.1 Engineering Department Self-Assessments

a. Inspection Scope

The team reviewed conclusions and resolution of a sample of findings for self-assessments of the plant engineering, design engineering and fuel safety and analysis departments.

b. Observations and Findings

b.1 Plant Engineering Self-Assessment

The team reviewed RST-1999-001-ENP "Plant Engineering Functional Area Assessment." The licensee assessment documented 23 findings, 4 recommendations for improvement, and 5 strengths. Six of the findings were considered major and 25 CRs were written on the findings. The team concluded that the assessment was thorough and the corrective actions were appropriate to resolve the issues.

b.2 Design Engineering Self-Assessment

The team reviewed RST-1999-001-NED "Design Engineering Functional Area Assessment." This assessment identified 95 findings, 16 recommendations for improvement, and 1 strength. From these findings 8 major issues were identified and the 87 CRs adequately captured the identified issues. The team reviewed 16 of these CRs to evaluate corrective actions. The team concluded that the assessment was thorough and that appropriate corrective actions had been taken to resolve the assessment findings.

b.3 Fuel Safety and Analysis Self-Assessments

The team reviewed RST-1999-001-NFG "Functional Area Assessment Report of the Nuclear Fuel Safety and Analysis Department (NFG)." The licensee's stated objective was to identify strengths, weaknesses, as well as areas for improvement, and to determine the overall readiness of the NFG. The scope of this assessment included interviews of NFG as well as other departments supported by NFG, reviews of department procedures and closed CRs assigned to NFG. The assessment identified findings in 19-key attribute areas such as department staffing levels, procedure quality, department backlogs, and personnel training. The licensee concluded that upon completion of all restart items identified, that the NFG would be in the appropriate state of readiness for restart. The team considered the assessment scope and methodology appropriate and conclusions supported by the findings.

The team reviewed licensee corrective actions to a finding identified in RST-1999-001-NFG associated with a lack of a procedure for review of Westinghouse WCAP or other vendor reports (CR 99-10066). The licensee issued Procedure 12-EHP 5043.OAR.001 "Owner's Acceptance Review" to address this issue which the team considered an adequate resolution.

The team reviewed licensee corrective actions to a finding discussed in RST-1999-001-NFG associated with an error identified in a fuel vendor computer code used for fuel rod internal pressure calculations, which resulted in reduced internal pressure margins when compared to the previous licensed model (CR 97-3022). This generic issue identified by the vendor was applicable to Westinghouse fuel rods containing integral fuel burnable absorber. The vendor was investigating root causes and recommended corrective actions on a generic basis. The licensee determined that this issue potentially placed the plant in noncompliance with the 17 percent clad oxidation requirements of 10 CFR 50.46(b)(2) and reported this condition in LER 50-315/1997-027-01. The licensee subsequently determined based on a vendor calculation that compliance with 10 CFR 50.46 would be maintained for Unit 1 and for

Unit 2. However, at 257 effective full power days for Unit 2, the pellet-to -clad gap reopening would need further evaluation. The licensee identified in CR 97-03022 that a justification for continued operation should be completed before the time at which fuel clad gap reopening may occur. For operation of Unit 2 beyond this point the licensee specified in Action 1 of CR 99-26376, to completed a justification for continued operation or demonstrate through revised analysis that a non-conformance did not exist with respect to fuel clad lift off by March 1, 2001. The licensee actions to date, were consistent with actions found acceptable to the NRC as described in Information Notice 98-029 "Predicted Increase in Fuel Rod Cladding Oxidation." Therefore, LER 50-315/1997-027-01 was closed.

The team reviewed SA-1999-004-NFG "Assessment Report of the AEP [American Electric Power]/Westinghouse Interface." The purpose of this assessment was to evaluate the readiness of the AEP/Westinghouse design interface and the quality of the current Westinghouse products to support restart activities. The assessment scope included interviews, review of procedures controlling the interface, and review of work products that crossed the AEP/Westinghouse interface. Based on a number of findings the licensee concluded that the AEP/Westinghouse interface was not adequate to support restart. The team considered the assessment scope and methodology appropriate and conclusions supported by the findings. The licensee completed actions documented in CR 99-23555 to correct the key issues identified. The licensee issued six procedures, formally endorsed the "Westinghouse Project Quality Plan, Q&ES 1374, Revision 3" and completed augmented training in this area. Previously the NRC had identified an inspection followup item (IFI) 50-315/98004-17; IFI 50-316/98004-17 which identified that the AEP to Westinghouse interface was a potential root cause to several of the Confirmatory Action Letter items and identified that additional reviews were warranted. Based on licensee corrective actions which included additional reviews of the AEP/Westinghouse design interface IFI 50-315/98004-17; IFI 50-316/98004-17 was closed. The team considered the corrective actions to resolve the assessment findings adequate.

The team reviewed SA-1999-008-NFG "Engineering Technical Issues Resolution." The licensee's objective was to identify how technical issues were being resolved within the plant engineering, design engineering and fuels, safety and analysis departments. A team of AEP and contract personnel evaluated five technical issues which crossed the functional boundaries of these three departments. The licensee concluded that the technical solution team concepts were sound and that the issues were effectively resolved. This assessment also identified issues with scheduling and single point-of-accountability, which the licensee took actions to resolve as documented in CR 99-21528. The team considered the assessment scope and methodology appropriate and conclusions supported by the findings.

The team reviewed licensee corrective actions to a finding identified in SA-1999-008-NFG. The licensee identified a concern for the habitability of the control room due to the presence of ventilation system chiller (Freon) relief valves and piping (CR 99-02199) which are within the control room envelope. The licensee performed calculation MD-12-HV-016-N "Control Room Habitability Following R-22 Release from Chiller Units HV-ACR-1 and HV-ACR-2," which demonstrated that the Freon concentration would remain below an Occupational Safety and Health Administration limit of 1000 parts per million on a time waited average basis with an expected fresh air makeup of in excess of 700 cubic feet per minute. The team identified that per

Step 4.4.1 of Procedure PMP 2080EPP.110 “Toxic Gas Release Guidelines,” that when toxic or unknown gas is detected, the control room envelope is isolated. The team noted that this action would isolate makeup air to the control room and invalidate the habitability conclusions of calculation MD -12-HV-016-N. This issue appeared to stem from a lack of consideration for the required operational system alignment impact on the calculation assumptions.

10 CFR Part 50, Appendix B, Criterion III, requires, in part, that design control measures shall provide for verifying or checking the adequacy of design such as by the performance of design reviews. Contrary to this requirement, for calculation MD-12-HV-016-N completed on December 2, 1999, the licensee had not performed adequate reviews to identify and verify the adequacy of the plant design ventilation configuration for the control room. Failure to complete an adequate design review of the control room ventilation system is a Violation of 10 CFR Part 50, Appendix B, Criterion III. However, this Severity Level IV Violation is being treated as a Non-Cited Violation (50-316/2000003-03), consistent with Section VI.A.1 of the NRC Enforcement Policy. The licensee documented in CR 00-07042 that the calculation impact assessment failed to recognize the conflict. The licensee subsequently identified in CR 00-07042, a requirement to add instructions to procedure PMP 2080 EPP.110, to not isolate the control room envelope upon detection of R-22 (Freon). The team considered the proposed action adequate to resolve this issue.

c. Conclusions

The team considered the engineering department self-assessments effective and resolution of assessment findings adequate. However, the team identified inadequate resolution of one assessment finding associated with a calculation for the control room habitability. The licensee had failed to recognize the required ventilation system configuration in the calculation evaluating the effects of a Freon release to the control room, which was considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III. This issue stemmed from a lack of consideration for the operational alignment of the system and indicated a lack of coordination and control in the calculation process.

E7.2 Performance Assurance Department Audits for the Engineering Department

a. Inspection Scope

The team reviewed conclusions and resolution of findings of PA department audits of the engineering department functions and programs.

b. Observations and Findings

The team reviewed audit PA-99-12/269, “Design Control and Design Changes,” and audit summary report. The purpose of this audit was to provide a basis for determining if the measures put in place to improve the design change and design control processes were effective. The scope of the audit included calculations, component evaluations, temporary modifications, design change packages, engineering hold, technical direction memos and design change deviation information requests. The team considered that the assessment personnel were well qualified for conducting an effective audit based on their education and work experience. The scope of the audit was appropriately

comprehensive and conclusions adequately supported by the observations. Findings had been entered into the corrective action system and appropriately resolved. Overall, the audit personnel concluded that training, design and configuration controls were acceptable.

The team reviewed PA-99-21 “ASME Section XI Repairs/Replacement Program (PMI-5075)” and audit summary report. The PA Department staff concluded that the plant ASME Section XI Repair/Replacement Program for components and supports met the requirements of ASME Section XI, 1989 Edition. The scope of this audit included the Unit 1 SG replacement and 11 ASME Code Repair/Replacement activities. The team considered the scope appropriate for a program review. However, the scope of the audit was focused on program documentation, vice evaluating in-process work conducted under this program (e.g., performance based audit). Specific program products which were not evaluated or were limited included: (1) the licensee had not observed any actual repair/replacement work and the SG replacement activity had not yet started, (2) only one weld procedure specification related to the SG replacement activity was documented as reviewed, and (3) no weld procedure qualification records were reviewed. This audit found all activities acceptable and did not identify any findings. The team considered this audit adequate, but narrowly focused on program documentation.

The team reviewed SR-99-0042 “Preservation of Nuclear Safety Margins,” dated January 19, 2000. The Performance Assurance department audited Westinghouse to assess the interface of Cook design information with plant accident analysis, focusing on the preservation of nuclear safety margins. The audit identified weaknesses in the control of design inputs to the Accident Analysis Input Assumptions Table values, but concluded that these weaknesses did not affect the conclusions of the accident analysis of record. Specifically, the audit identified slightly non-conservative discrepancies with respect to the values assumed in the accident analysis for start times for the centrifugal charging pumps, RHR pumps, and containment spray pumps. These issues were adequately evaluated and corrected by the licensee as documented in CR 99-22552 and 99-23423. The team considered the assessment scope and methodology appropriate and conclusions supported by the findings.

c. Conclusions

The team considered the Performance Assurance department audits of engineering adequate and the findings appropriately resolved. However, the team identified that the ASME Section XI Repair/Replacement audit was narrowly focused on program documentation, vice observations of in process work.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Resolution of Hydrogen Mitigation System Operability (CSC Item 11)

a. Inspection Scope

The NRC, identified as CSC Item 11, concerns associated with Hydrogen Mitigation System Operability and Materiel Condition. This issue had been previously reviewed during NRC Inspection 50-315/2000007(DRS); 50-316/2000007(DRS) and could not be closed because a revised hydrogen analysis had not been completed and insufficient

documentation existed to reach a conclusion on the operability of the hydrogen skimmer and air recirculation (CEQ) system. To evaluate licensee performance in resolving operability of the CEQ system, the team reviewed supporting calculations, test data, and other completed corrective actions documented in RAP 11 “Resolution of Hydrogen Mitigation System Operability and Materiel Condition Issues.”

b. Observations and Findings

The team reviewed MD-2-HV-011-N “Donald C. Cook Unit 2 Containment Air Recirculation/Hydrogen Skimmer System Pressure Drop Calculation.” The purpose of this calculation was to develop a thermal hydraulic model of the Containment Air Recirculation/ Hydrogen Skimmer System for predicting system flowrates under accident conditions. The predicted flowrates through branches of the CEQ system were compared to actual flow measured in the branches under different system configurations. The flow rates predicted by the model did not match the test data with reasonable accuracy. To adjust the model to more accurately match the test data the licensee used “Balancing Parameters” to change the modeled position of system valves to match the test data. The final model run (Case 2.2B) closely matched the test data except that for the pressurizer branch in which the model under-predicted the test data by 16 percent. The model was then used to predict the flows in each of the CEQ system branches under conditions of maximum and minimum ice condenser resistence (Case 3 and 4). The limiting flows predicted for these runs were then compared with the minimum flowrates used as input assumptions for analysis FAI/99-27 “Hydrogen Subcompartment Analyses for the D. C. Cook Unit 1 and 2 Containments Following DBA LOCAs [Loss of Coolant Accidents].” The predicted flowrates to each of the areas served by the CEQ system were greater than the minimum flows used in the hydrogen analysis FAI/99-27 by considerable margins. The lowest margin was 17 percent for the branch of system 2-HV-CEQ-2 serving the pressurizer enclosure. The licensee documented in action 10 of CR 00-02673 that the maximum instrument uncertainty of 10 percent when comparing the results of calculation MD-2-HV-011-N to the hydrogen analysis FAI/99-27, which was conservative with respect to the minimum 17 percent margin available. The licensee demonstrated that the predicted CEQ system flowrates (including assessments for uncertainty) would preclude local areas of hydrogen from exceeding 4 percent following a LOCA which was consistent with Regulatory Guide 1.7 “Control of Combustible Gas Concentrations in Containment Following a Loss-Of-Coolant Accident.” Based on this analysis the CEQ system would function adequately to mitigate subcompartment containment hydrogen buildup following a LOCA.

The team reviewed analysis AEP-99-274 “Transmittal of Post-LOCA Hydrogen Evaluation Report Rev. 4 and SECL 99-002 Rev. 3." This analysis provided an update of the previous post-LOCA global containment hydrogen analysis. This update was necessary, due to changes in the assumed fraction of the core subject to hydrogen production from the zirconium-water reaction, revised containment temperature profiles, revised masses of corrodible materials in containment, revised containment spray profiles, change in core and sump energy deposition and change in the existing inventory of hydrogen in the reactor coolant system. This analysis demonstrated for post-LOCA scenarios that containment hydrogen remained less than 4 percent. The team verified that input assumptions and conclusions were consistent with 10 CFR 50.44 requirements and Regulatory Guide 1.7.

c. Conclusions

Through testing and analysis, the licensee adequately demonstrated that post accident containment hydrogen levels would remain below 4 percent. Therefore, CSC Item 11 associated with Hydrogen Mitigation System Operability was closed.

E8.2 (Closed) RAM Item R.1.28 - Emergency Diesel Generator Air System

a. Inspection Scope

The licensee identified in LER 50-315/99011-00 that the air system for the EDGs might not support long term operability due to an error in the original system design. This issue had been previously reviewed during NRC Inspection 50-315/2000007(DRS); 50-316/2000007(DRS) and could not be closed because insufficient documentation existed to demonstrate the operability of this system. The team reviewed the licensee's revised Engineering Action Plan 99-282 "EDG Starting Air," supporting calculation and completed post modification testing to resolve this issue.

b. Observations and Findings

The air system of the EDG provided the function of EDG starting, instrument air supply for selected instruments and EDG shutdown via the throttle control cylinder. The system included two safety grade receivers capable of two EDG starts from each air receiver and air for the instrument air system. Based on preoperational test data the pressure in the air receiver s could decrease to as low as 132 pounds per square inch gauge (psig) following an emergency diesel generator start. 100 psig air pressure is needed to keep the pneumatically controlled throttle control cylinders actuation rod retracted to maintain fuel flow for the EDG. For long term EDG operation the system relied on air supplied by two nonsafety/nonseismic air compressor systems. To ensure long term operability the licensee performed modifications to install safety-related piping and compressors for makeup air supply to the EDG air start receivers as described in Engineering Action Plan 99-282.

The design change packages to install new safety-related piping and air compressors for the Unit 2 EDG air systems and supporting calculation had been previously reviewed by the NRC. The supporting calculation MD-12-DG-003-N "Capacity Requirement for Emergency Diesel Generators Starting Air System" did not demonstrate conclusively that the new safety-related compressors and piping would support long term EDG operation. Therefore, the team reviewed the completed post modification testing which measured system air leakage and demonstrated system performance under conditions which bound the worst case operating conditions discussed above. The team observed portions of the post modification test for the AB diesel 02-DCP-487-TP.2 "DG2AB Starting Air Compressor Test-2QT-142-AB2." The new compressor provided in excess of 30 cubic feet per minute of air to the air receiver which exceeded the design minimum flowrate of 25 cubic feet per minute. This testing demonstrated that the new safety-related compressors and piping would support continued air service for sustained EDG operation.

c. Conclusions

The licensee demonstrated through post modification testing, on the 2 AB EDG, that the modified EDG air system would support sustained EDG operation. Therefore, the team considered that operability of the EDGs was adequately resolved and LER 50-315/99011-00 (RAM Item R.1.28) was closed.

E8.3 Emergency Diesel Generator Fuel Supply & Surveillance Procedure

a. Inspection Scope

The NRC had identified an unresolved item (URI) 50-315/99007-04(DRS); 50-316/99007-04(DRS) concerning demonstration of the EDG fuel oil storage tank capacity and identification of the plant license basis for the EDG fuel oil storage tanks. The team reviewed the licensee's corrective actions for this issue documented in CR 99-19773 and CR 99-19705.

b. Observations and Findings

The team evaluated the licensee's investigation and corrective actions for URI 50-315/99007-04(DRS); 50-316/99007-04(DRS) concerning demonstration of the EDG fuel oil storage tank capacity. To address this issue, the licensee made changes to the EOPs to conserve and replenish the diesel fuel oil supply, and completed calculation MD-12-DG-004-N "Diesel Fuel Oil Consumption Rate, Verification of DG Fuel Oil Storage and Day Tank Volumes, and Transfer Pump and Diesel Exhaust Line Sizing." The licensee also identified that the licensing basis sizing for the EDG fuel oil supply was based on one EDG in operation for 7 days. Based on these corrective actions the team considered URI 50-315/99007-04(DRS); 50-316/99007-04(DRS) had been adequately addressed and was closed. However, the team identified that an incorrect minimum tank level value was incorporated into the EDG surveillance procedure and that the licensee had installed an undocumented tank vent line modification as discussed in the following sections.

b.1 Incorrect Level Uncertainty Incorporated Into The Fuel Oil Storage Tank (FOST) Level Surveillance Procedure

Technical Specification 3.8.1.1 and 3.8.1.2 required that each separate diesel fuel storage system contain a minimum indicated volume of 46000 gallons of fuel to consider the EDGs operable. The licensee fuel oil storage system included two buried FOSTs, which supply diesel fuel oil to EDGs in both Units. Each bulk storage tank is approximately 12 feet in diameter, 70 feet long and anchored to a concrete pad with a slope of 9 inches over the tank length. The indicated tank level is measured at the downslope end of the FOST.

The team reviewed calculation MD-12-DG-004-N and confirmed that the usable EDG storage capacity of the tanks was in excess of that required to support a single EDG running for 7 days. In Section 7.2.4 of this calculation, the licensee established the required fuel level of "approximately 8.51 feet" and stated that this is the level that the fuel oil storage tanks must be filled to meet NRC Regulatory Guide1.137 and was conservative with respect to TS requirements. This calculated tank level, neglected the impact of instrument error and tank slope on the indicated tank level and did not

reference calculation 1-2-UNC-056, Calc 1 “DG Fuel Oil Storage Tank Level” which did adjust for these factors. In calculation 1-2-UNC-056, Calc 1, the licensee had identified an indicated level uncertainty of +0.882 feet, -0.599 feet and recommended that the minimum indicated tank level to comply with TS be raised to 9.5 feet from the current level of 8.54 feet. However, as discussed below, this value was not correctly incorporated into the FOST surveillance procedure. The team also noted that these calculations differed in unusable tank volume and usable tank volume. The licensee issued CR 00-6786 to document the inconsistencies in these calculations, which were caused by failure of the licensee to perform an adequate impact assessment for calculation MD-12-DG-004-N. The inconsistencies between calculations indicated a lack of coordination and control in the calculation process.

An uncontrolled document was used to make a surveillance procedure change, that directly contributed to the incorporation of an incorrect value for minimum fuel oil storage tank level. The licensee had previously identified on April 5, 1999, in CR 99-07597, that the FOST level gauge instrument accuracy was not adequately addressed in the surveillance tests 01(02)-OHP.4030.STP.027AB and 01(02)-OHP.4030.STP.027CD. Action 4 of this CR was completed on April 3, 2000, when Revision 13 of 02-OHP.4030.STP.027AB “AB Diesel Generator Operability Test (Train B),” was issued. However, the team identified that the this procedure revision was inadequate. The author of Revision 13, of this procedure had inappropriately used uncertainty data from DIT S-00405-00 and an uncontrolled spreadsheet to establish an incorrect minimum tank level surveillance value of 8 feet 10.5 inches, vice a required minimum level of 9.5 feet as discussed above. Further, the procedure technical review and cross discipline review failed to identified this error, because of an inadequate review of source documents. 10 CFR Part 50, Appendix B, Criterion III, requires in part that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures and instructions. Failure to translate the appropriate design number for minimum fuel oil storage tank level on the AB FOST, into 02-OHP.4030.STP.027AB is a Violation of 10 CFR Part 50, Appendix B, Criterion III. However, this Severity Level IV Violation is being treated as a Non-Cited Violation (50-316/2000003-04), consistent with Section VI.A.1 of the NRC Enforcement Policy. The licensee initiated CR 00-06774 to identify that use of the diesel oil fuel oil storage tank level indication does not ensure tank levels above the TS minimum requirements and was evaluating the reportability requirements for the previously low tank levels. The licensee subsequently identified that use of the tank level indicators, vice a dip stick was not consistent with the plant license basis and that tank level alarms did not incorporate level uncertainties. Additionally, the licensee identified two other operations procedure writers who may have used an uncontrolled spreadsheet for the source of instrument uncertainty data in making procedure changes. The licensee issued CRs 00-06923 and 00-06774 to document these issues. The team considered that these errors stemmed from a lack of coordination and control (of an unapproved instrument uncertainty spread sheet) in the calculation process.

To confirm EDG operability the team reviewed the most recent surveillance tests completed for the EDG fuel oil storage tanks documented in Procedures 02-OHP.4030.STP.027AB “AB Diesel Generator Operability Test (Train B) and 02-OHP.4030.STP.027CD “CD Diesel Generator Operability Test (Train A).” The recorded levels where at or above 10 feet and thus the team had no current operability concerns. The lowest level reached in these tanks identified by the licensee, in review

of the previous 2 years worth of surveillance test data, was 9 feet 2 inches in the AB FOST recorded on February 23, 1998, and 9.0 feet recorded on July 19, 1999, in the CD FOST and the licensee was evaluating the reporting requirements of 10 CFR 50.72 for this condition.

b.2 Undocumented Modification On The FOST Vent Line

During a walkdown on May 9, 2000, of the FOST 12-TK-47-CD supplying the CD EDGs for each unit, the team identified a shroud (4-5 feet in length) covering the tank vent. The licensee believed that this shroud had been installed for a number of years and that it originally served to direct any fuel oil overflow into a berm below the tank vent. However, the licensee could not identify any documentation for installation of the shroud and the configuration was not consistent with the vent arrangement identified on drawing 1-5191-6 “Transformer Decks Drains & Piping Diesel Fuel Oil Storage Tank & Piping Unit No. 1," Revision 6. This drawing identified a “Buckeye # 786" on the end of the 4 inch vent pipe (a bell shaped vent cap). The vent cap serves to prevent intrusion of water or foreign material while allowing air to vent from the tank as it is filled or drained. If this vent cap was restricted/or blocked it would limit the supply of fuel for the EDGs. The failure to identify the undocumented modification during the previous ESRR walkdowns indicated that this process was not fully effective in supporting restoration of the system materiel condition. The team examined the AB FOST tank vent line and confirmed that it was in accordance with the design drawings.

10 CFR Part 50, Appendix B, Criterion III, requires in part that design changes including field changes shall be subject to design control measures commensurate with those applied to the original design. Contrary to this requirement, as of May 9, 2000, the licensee had not applied design controls including a documented design review for the modified the FOST 12-TK-47-CD tank vent line. Failure to apply design controls for modification of the 12-TK-47-CD tank vent line is a Violation of 10 CFR Part 50, Appendix B, Criterion III. However, this Severity Level IV Violation is being treated as a Non-Cited Violation (50-316/2000003-05), consistent with Section VI.A.1 of the NRC Enforcement Policy. The licensee considered that this shroud had not heretofore impacted the vent line function, because any plugging would have been identified during the periodic refilling of the tank. The licensee documented this issue on CR 00-06675 and removed the shroud from this tank to restore the original design configuration. The team considered this issue adequately resolved.

b.3 Emergency Diesel Generator Power Factor

The EDG load test surveillance requirements of Section 4.8.1.1.2 of the Unit 2 TS required that the generator be operated at a power factor of less than or equal to 0.86 for at least 8 hours. During plant walkdowns, the team noted that there was no installed power factor meter for the EDG generators and the requirement was met by maintaining the operation of the generator within a designated operating region described in Figure No. 1 of operating procedure 02-OHP 4030.STP.027AB, "AB Diesel Generator Operability Test (Train B)." The team identified that no documented calculations existed to support the acceptance criteria delineated as lines bounding an acceptable operating region on this figure. The team checked using applicable calculations, that the points on the acceptance criterion lines did accurately reflect the acceptable power factor. However, the points on the line were not adjusted for potential instrument inaccuracy, which could change the required location of these lines on this graph.

Criterion III of 10 CFR Part 50, Appendix B, requires, in part, that the design control measures shall provide for the adequacy of design, such as by the use of alternate or simplified calculational methods. Failure to perform an adequate design review (based on documented calculations) in determining the EDG power factor acceptance criteria defined in Figure No. 1 of 02-OHP 4030.STP.027AB is a Violation of 10 CFR Part 50, Appendix B, Criterion III. However, this Severity Level IV Violation is being treated as a Non-Cited Violation (50-316/2000003-06), consistent with Section VI.A.1 of the NRC Enforcement Policy. The licensee issued CR 00-07063 to document this issue in the corrective action system. The lack of supporting calculations for the EDG power factor acceptance criteria indicated a lack of coordination and control in the calculation process.

c. Conclusions

The licensee had completed a calculation to address URI 50-315/99007-04(DRS); 50-316/99007-04(DRS) associated with the EDG fuel oil storage tank capacity and this issue was closed. However, the calculation used to close this issue did not consider instrument uncertainty or tank slope in determining a minimum FOST level. The instrument uncertainty and tank slope was properly accounted for in a separate calculation, although this calculation did not reference or acknowledge the former calculation. The inconsistencies in these calculations indicated a lack of coordination and control in the calculation process.

An uncontrolled document was used to make a surveillance procedure change, that directly contributed to the incorporation of an incorrect value for minimum fuel oil storage tank level, which was considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III. This issue stemmed from a lack of coordination and control in the calculation process.

The team identified a shroud installed on the CD FOST vent line. This configuration was not incorporated into the vent line drawing and had reportedly been installed for a number of years. Failure to apply design controls in installation of the CD fuel oil storage tank vent line shroud is considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III. The failure to identify this issue during previous ESRR walkdowns indicated that this process was not fully effective in restoration of the system materiel condition.

The team identified that EDG surveillance procedure acceptance criterion for the power factor was not supported by documented calculations and did not consider the potential instrument inaccuracies. Failure to establish the design basis calculation for the acceptance criteria for power factor in the EDG surveillance procedure is considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III. The lack of supporting calculations for the EDG power factor acceptance criteria indicated a lack of coordination and control in the calculation process.

V. Management Meetings

X1 Exit Meeting Summary

The team discussed the progress of the inspection with licensee representatives on a daily basis and presented inspection results to members of the licensee management and public at the conclusion of the inspection on May 22, 2000. The licensee acknowledged the findings presented and did not identify any of the potential report input as proprietary.

PARTIAL LIST OF PERSONS CONTACTED

NRC Personnel
J. Grobe, Director, Reactor Safety, RIII
B. Bartlett, NRC, SRI
A. Vegel, NRC, Branch Chief, RIII

AEP Personnel
R. Powers, Senior Vice President
C. Bakken, Site Vice President
M. Rencheck, Engineering Vice President
J. Pollock, Plant Manager
M. Finissi, Plant Engineering Director
S. Greenlee, Design Engineering Director
D. Garner, Nuclear Fuels, Safety & Analysis, Director
J. Molden, Director, Operations
W. Kropp, Performance Assurance Director
R. Godley, Director Reg Affairs
T. Noonan, Restart Director
L. Weber, Operations Manager
S. Partin, Assistant OPS Manager
R. Crane, Regulatory Affairs
M. Danford, Correction Action Planning Manager
R. Gaston, Compliance Manager
R. Meister, Regulatory Affairs
B. Smalldridge, Operations
L. Thornsberry, Systems Engineering Manager
G. Mountain, Regulatory Affairs/Compliance

Members of the Public
R. Whale, MPSC/Engineer
D. Salter, HGP, INC.
R. Wilson, Associated Press
M. Galbraith, South Bend Tribune
D. Malone, Consumers Energy
C. Cox, The Herald-Pallendium
M. Poluhanycz, Citizen
D. Harris, WSJM
R. Thuraldses, WSJV 28
B. Bellinor, South Bend Tribune

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500	Corrective Action
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 93802:	Operational Safety Team Inspection

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-316/2000003-01	NCV	Failure to follow procedures for CVCS auto makeup
50-316/2000003-02	NCV	Failure to perform required periodic reviews of procedures
50-316/2000003-03	NCV	Failure to recognize the required ventilation system configuration in the calculation evaluating the effects of a Freon release to the control room
50-316/2000003-04	NCV	Failure to translate the appropriate level instrument uncertainty into the fuel oil storage tank surveillance procedure
50-316/2000003-05	NCV	Failure to apply design controls in installation of the CD fuel oil storage tank vent line shroud
50-316/2000003-06	NCV	Failure to establish a design basis calculation for the EDG power factor

Closed

11	CSC	Resolution of Hydrogen Mitigation System Operability and Materiel Condition Issues
14/14G	CSC	Resolution of Programmatic Final Readiness Reviews
15/15B	CSC	Resolution of Functional Area Final Readiness Reviews
C.3.3.d	RAM	Effectiveness of restart simulator/required training necessary to re-familiarize personnel with operating conditions
C.3.3.e	RAM	Assessment of Plant Staff Performance During Restart and Sustained Control Room Observations

C.4.b	RAM	Operability of Required Secondary and Support Systems
(RAM Item 1.28)/ 50-315/99011-00	LER	Air System for Emergency Diesel Generators (EDG) May Not Support Long Term Operability Due to Original Design Error
50-315/1997-027-01	LER	Westinghouse Integral Fuel Burnable Absorber Fuel Rods
50-315/99007-04 50-316/99007-04	URI	EDG Fuel Oil Storage Tank Capacity and License Basis
50-315/98004-17 50-316/98004-17	IFI	AEP to Westinghouse design interface was a potential root cause to several of the Confirmatory Action Letter items
50-316/2000003-01	NCV	Failure to follow procedures for CVCS auto makeup
50-316/2000003-02	NCV	Failure to perform required periodic reviews of procedures
50-316/2000003-03	NCV	Failure to recognize the required ventilation system configuration in the calculation evaluating the effects of a Freon release to the control room
50-316/2000003-04	NCV	Failure to translate the appropriate level instrument uncertainty into the fuel oil storage tank surveillance procedure
50-316/2000003-05	NCV	Failure to apply design controls in installation of the CD fuel oil storage tank vent line shroud
50-316/2000003-06	NCV	Failure to establish a design basis calculation for the EDG power factor

<u>Discussed</u>

13/13B	CSC	Systems and Containment Readiness
C.4.a	RAM	Operability of TS Systems
C.4.c	RAM	Results of Pre-startup Testing
C.4.d	RAM	Adequacy of System Lineups
C.4.g	RAM	Adequacy of the Power Ascension Testing Program

LIST OF ACRONYMS

AEP	American Electric Power
AFW	Auxiliary Feedwater
AR	Action Request
CCP	Centrifugal Charging Pump
CCW	Component Cooling Water
CEQ	Hydrogen Skimmer and Air Recirculation
CFR	Code of Federal Regulations
CR	Condition Report
CSC	Case Specific Checklist
CVCS	Chemical and Volume Control System
DCP	Design Change Package
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generators
EOP	Emergency Operating Procedure
ESRR	Expanded System Readiness Review
ESW	Essential Service Water
FOST	Fuel Oil Storage Tank
I&C	Instrumentation and Controls
IFI	Inspection Followup Item
IHP	Instrument Head Procedure
IMP	Instrument Maintenance Procedure
IST	In-Service Test
JO	Job Order
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MC	Manual Chapter
MDAFW	Motor Driven Auxiliary Feedwater
MHP	Maintenance Head Procedure
MOV	Motor Operated Valve
NCV	Non-Cited Violation
NFG	Nuclear fule safety and analysis department
NLO	Non-licensed Operator
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
ODE	Operability Determination Evaluation
OE	Operating Experience
OHI	Operations Head Instruction
OHP	Operations Head Procedure
PA	Performance Assurance
PMI	Plant Manager’s Instruction
PMP	Plant Manager’s Procedure
PMSO	Plant Manager’s Standing Order
PMT	Post Maintenance Testing
PDR	Public Document Room
PA	Performance Assurance
psig	Pounds Per Square Inch Gage
RAM	Restart Action Matrix

RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RO	Reactor Operator
RWST	Refueling Water Storage Tank
SA	Self-assessment
SM	Shift Manager
SRO	Senior Reactor Operator
SRRB	System Readiness Review Board
STA	Shift Technical Advisor
STP	System Test Plan
TM	Temporary Modification
TS	Technical Specification
URI	Unresolved Item
US	Unit Supervisor
Vac	Volts alternating current
Vdc	Volts direct current

ATTACHMENT A - List of Documents Requested Prior to Inspection

Site organizational charts
Copies of detailed work schedule for the two weeks onsite (planned operations evolutions, maintenance and surveillance testing)
Access to a copy of EOPs, abnormal procedures, IPE, TS, USAR, TS interpretations, system descriptions (accessible from work area at site)
Listing of points of contacts and phone numbers for personnel in Operations, Maintenance, Engineering, Operator training, and Quality Assurance (including system engineers for systems listed in 15)
Administrative/Operations procedures governing:

- Procedure Use and Adherence
- Conduct of operations
- Control room operator and SS Logkeeping
- Standards/expectations on communications, panel walkdowns, shift briefings
- Initiation of a work order, isolation of equipment, post maintenance testing control, return to service/operations
- Corrective Action Program procedure
- System configuration controls
- Operability Determinations
- Jumper/Bypass/Temporary Modifications
- Locked Valve and Breaker Program
- Independent Verification
- Operator Workarounds
- Reactivity management

Power ascension test schedule
Copies of station or Operations long term operational objectives/ operating plan (if one exists)
Plant Startup and Operations procedures, (from cold S/D thru full power Ops, including dilution to ECB, approach to criticality, etc.)
TS required operations surveillances - hourly, shiftly, and daily completed copies of each for a day when the plant was last operated at 100 percent power and blank copies of each to be taken when the plant returns to Mode 1 operation
Log sheets for all Unit 2 operator tours outside of the control room:

- completed copy for a day when the plant was last operated at 100 percent power
- completed copy for a recent day in the plant's current mode (e.g., Jan/00).
- blank copy of logs to be taken when the plant returns to mode 1 operation.

Last 21 days of Control Room Narrative Logs (Jan 26 '00 - 21 days)
List of Operator workarounds and control room deficiencies (as of 2 weeks prior to inspection)
List of outstanding jumper/bypass/temporary modifications (as of 2 weeks prior to inspection) (include system, #, date installed)
List of degraded equipment conditions (as of 2 weeks prior to inspection)
Normal system operating procedures, system P&IDs (11x17), and valve lineup checklists for the following systems: emergency service water, component cooling water, residual heat removal, diesel generator, safety injection
Planned simulator training schedule and objectives for on-site weeks
List all Unit 2 licensed ROs/SROs. Specify whether license is active or inactive.
Provide copies of shift assignments and schedules
List of open Operability evaluations (GL 91-18 issues) (as of 2 weeks prior to inspection)
List of outstanding safety-related work requests (as of 2 weeks prior to inspection; need minimum: No., description, system; sorted by system)
List of open condition reports (include description)

List of oldest safety-related work requests still open (for all systems; include ID, system, description, date initiated)
Listing of problem reports involving configuration control problems (i.e., components found out of position) for last 6 months and current status
Maintenance Rule system performance indicators/summaries for the last 6 months, for the systems
Copies of last completed surveillance test for the systems listed in 15.
Copies of the most recent run on each diesel generator (include operators logs (local and control room). Also provide DG air-start drawing, air-start logic, and electric control logic.
List of major design changes implemented in last 2 years (include ID, description, affected systems).
List of open and closed conditions adverse to quality/deviation reports/nonconformance reports for last 6 months
Administrative procedure governing self-assessments and performance of QA/PA assessments and audits
List of any self-assessments performed since 6/99 for Ops, Maint, Engr
List of QA/PA surveillances and audits in Ops, Maint, Engr since 2/99
List of findings (condition reports) that resulted from Engineering self-assessments since 2/99
List of QA/PA findings sorted by functional areas
System Final Readiness Review Reports for systems in 15
System Restart Deferred Items/Justification Lists for systems in 15 (if there are any)
System Readiness Review Restart Procedure for systems in 15
1 Copy of the associated PA audit for RAPs: 13, 14, 15
Closure package for RAPs 13, 14, 15 (CSCs 13/13B, 14/14G, 15/15B) which should include supporting documentation of the corrective actions completed
System notebooks as part of RAP 13 (CSC 13/13B) for system in 15 (only need access to notebooks if too voluminous)
RWST level instrumentation setpoint calculations
Engineering procedures governing control of instrument setpoints
Surveillance test procedures for RHR and SI system/valve interlocks
Administrative/engineering procedures for design changes and 10 CFR 50.59 safety evaluations
Containment close-out inspection procedure and results (if already performed)

ATTACHMENT B - Partial List of Documents Reviewed During Inspection

Procedures and Instructions
Operations Leadership Plan, Revision 12
12 EHI 5043, Drawing Control, Revision 1
02-EHP 4030.232.217A, DG2CD Load Sequencing & ESF Testing
02-EHP 4030.232.217B, DG2AB Load Sequencing & ESF Testing
02-EHP 4030.209.216, Containment Spray Nozzle Air Flow, Revision 0
12 EHP 5040 DES.001, Control of Design Input, Revision 0
12 EHP 5040 DES.003, Calculations, Revision 3a
12 EHP 5040.MOD.001, Temporary Modifications, Revision 2
12 EHP 5040.MOD.001, Temporary Modifications, Revision 4
12 EHP 5040.MOD.006, Design Change Packages, Revision 3
12-EHP 5043.DES.004, Design Drawings and Interim Drawings, Revision 0
12 EHP 5043 DES.017, Vendor Drawings, Revison 0a
12-EHP 5043.OAR.001 Owner's Acceptance Review, Revision 1a
02-IHP 4030.STP.226, RCS Valve Leak Rate Test, Revision 4
OHI-2000, Operations Department Guidance Policy, Revision 4
OHI-2212, Narrative Logkeeping, Revision 1
OHI-2000, Operations Department Guidance Policy, Revision 4
OHI-4000, Conduct of Operations: Standards, Revision 1
OHI-4011, Conduct of Operations (Shift Staffing), Revision 13
OHI-4012, Conduct of Operations (Shift Turnover), Revision 17
OHI-4013, Operators: Authorities and Responsibilities, Revision 11
OHI-4016, Conduct of Operations: Guidelines, Revision 3
OHI-4017, Control Board Monitoring, Revision 0
OHI-4024, Annunciator Response, Revision 0
02-OHP 4021.001.001, Plant Heatup From Cold Shutdown to Hot Standby, Revision 22
02-OHP 4021.001.002, Reactor Start-Up, Revision 21
02-OHP 4021.001.006, Power Escalation, Revision 16
02-OHP 4021.001.004, Plant Cooldown From Hot Standby to Cold Shutdown, Revision 23
02-OHP 4021.002.003, Reactor Coolant Pump Operation, Revision 10
02-OHP 4021 003.001, Letdown, Charging, and Seal Water Operation, Revision 15
12-OHP 4021.005.001, Boron Makeup System Operation, Revision 20
02-OHP 4021.005.007, Operation of Emergency Boration Flow Paths, Revision 4
02-OHP 4021.008.002, Placing Emergency Core Cooling System in Standby Readiness, Revision 12
02-OHP 4021.011.001, At-Power Operation Including Load Swings, Revision 5
02-OHP 4021.016.001, Filling and Venting the Component Cooling Water System (CCW), Revision 9
02-OHP 4021.016.003, Operation of the Component Cooling Water System During System Startup and Normal Operation, Revision 10
02-OHP 4022.017.001, Loss of RHR Cooling, Revision 11
02-OHP-4021.017.002, Placing in service the Residual Heat Removal System , Revision 10
12-OHP 4021.019.001, Operation of the Essential Service Water System, Revision 17
02-OHP 4021.032.001, AB DG2AB Operation, Revision 6
02-OHP 4021.056.002, Operation of Auxiliary Feed Pumps During Plant Start-Up and Shutdown, Revision 9
02-OHP 4030.001.002, Containment Inspection Tours, Revision 12
01-OHP 4030.066.4025, Unit One Appendix R Requirements for Unit 2, Revision 0
02-OHP 4030.232.001, Simultaneous Start Of AB And CD Diesel Generators

12-MHP 5021.001.154, Inspection of Rubber Expansion Joints, Revision 1
12-MHP5030.016.001 Component Cooling Water Heat Exchanger Inspection, Cleaning and Tube Plugging, Revision 2
02-IHP 4030.STP.226, RCS Valve Leak Rate Test, Revision 4
02-OHP 4030.STP.030, Daily and Shift Surveillance Checks, Revision 27
02-OHP.4030.STP.027AB AB Diesel Generator Operability Test (Train B), Revision 12 & 13
02-OHP 4030.STP.027CD, CD Diesel Generator Operability Test (Train A), Revision 15
02-OHP 4030.STP.020E, East Component Cooling Water Loop Surveillance Test
02-OHP 4030.STP.020W, West Component Cooling Water Loop Surveillance Test
02-OHP 4030.STP.054E, East Residual Heat Removal Train Operability Test - Shutdown
02-OHP 4030.STP.054W, West Residual Heat Removal Train Operability Test - Shutdown
02-OHP 4030.STP.008Q, East Residual Heat Removal Discharge Check Valve Test
02-OHP 4030.STP.008Q, West Residual Heat Removal Discharge Check Valve Test
02-OHP 4030.STP.008Q, ECCS Safety Valves Discharge Header Check Test Connection
02-OHP 4030.STP.022E, East Essential Service Water System Test
02-OHP 4030.STP.027AB, AB Diesel Generator Operability Test (Train B)
02-OHP 4030.STP.022W, West Essential Service Water System Test
02-EHP-4030-STP.226, RCS Pressure Isolation Valves Leak Rate Test
02-EHP-4030.209.216, Unit 2 Containment Spray System Nozzle Air Flow Test
02-OHP 5030.001.001, Operations Plant Tours, Revision 14
02-OHP 5030.APR.001, Appendix R Toolbox and Ladder Inventory, Revision 0
02-DCP-487-TP.2 DG2AB Starting Air Compressor Test-2QT-142-AB2, completed on May 12, 2000
21HP4030.STP.509, Residual Heat Removal Suction Valve Interlock Bistable Functional Test, Revision 1
PDP-7020.001, Internal and NSDRC Audits, Revision 2
PDP-7020.002, Field Observation Process, Revision 1
PDP-7020.003, Surveillance Process, Revision 1
PDP-7022.001, Performance Assurance Corrective Action Follow-Up and Escalation, Revision 0
PMI-2010, Procedures, Revision 27a
PMI-2294, Past Maintenance Testing Program, Revision 0
PMI-4010, Plant Operations Policy, Revision 12
PMI-4015, Reactivity Management Control, Revision 0
PMI 5043, Configuration Management System, Revision 0
PMI-7034, Self-Assessment Program, Revision 1
PMP-1040.SES.001, Safety Screenings/Evaluations, Revision 10
PMP-2010.PRC.002, Procedure Correction, Change, and Review, Revision 5
PMP 2010.PRC.003, Procedure Use and Adherence, Revision 1
PMP-2030.DOC.001, Document Control, Revision 0
PMP 2080EPP.110, Toxic Gas Release Guidelines, Revision 2
PMP 2110.CPS.001, Clearance Permit System, Revision 2
PMP-2110, Clearance Permit System, Revision 25
PMP-4010.OWA.001, Oversight and Control of Operator Workarounds, Revision 0
PMP-4030.216.001, CCW Flow Balance, Revision 0a
PMP-4043.APC.001, Abnormal Position Control, Revision 0
PMP-4043.CTP.001, Caution Tags, Revision 0
PMP-4043, Operational Configuration Control, Revision 0
PMP-4043.VLU.001, Valve Lineups and Position Control, Revision 0
PMP-4043.EQC.001, Equipment Control, Revision 0
PMP-4043.ICV.001, Independent and Concurrent Verification, Revision 0

PMP-7030.OPR.001, Operability Determination, Revision 4
PMP 7030.OE.001, Operating Experience, Revision 4
PMP 7034.SAP.001, Conduct of Non-Regulatory Self-Assessments, Revision 2
PMP 7200.RST.001, Restart Action Plans, Revision 6
PMP-7200.RST.002, Startup and Power Ascension, Revision 0b
PMP 7200.RST.003, System Turnover to Operations, Revision 2a
PMP-7200.RST.004, Expanded System Readiness Review Program, Revision 12b
PMP-7200.RST.005, Restart and Power Ascension Testing Program, Revision 0a
PMP-7200.RST.009, Programmatic Restart Readiness, Revision 2
PMP.7200.RST.010, Functional Area Restart Readiness, Revision 3
POL-7020, Audit Program Policy, Revision 1
UO-C-6200, Auxiliary Building Inspection Tour Training Lesson Plan, Revision 4
12-QHP-5070.NDE.001, Visual VT-2 Examination RCS System leakage Test, Revision 2

Design Changes
02 DCP-0561 -- CCW Heat Exchanger (2HE-15E, 2HE-15W) Tube Plugging, Revision 1
02 LDCP-5480 --Install ESW System Taps with Isolation Valves, Revision 0
02 DCP-0667 -- Modify AFW to Maintain Design Flowrate While Taking a Suction from ESW, Revision 0
DCP 181 -- Pressure Locking Modification for Valves 2-IMI\O-330/331 and 2–NMO-151/152/153
DCP-12-0168 -- Replacement of Aftercoolers in Emergency Diesel Generators
DCP-12-0183 -- Remove Auto-Close Feature for RHR valves IMO-128 and ICM-129
LDCP-02-4344 -- Leak Testing of Double Disc Gate Valves on the RWST Boundary

Temporary Modifications
02-97-0023 -- Installation of Drip Pots in Seal Oil System
02-98-0002 -- Drain hose from air handling unit at 2-WD-301
12-97-0043 -- Installation of Alternate Heating Boiler
12-99-0009 -- Connection to the 12KV System for power to SGRP Warehouse
2 IHP5021.EMP.022 -- Temporary power for containment weld receptacles
2 IHP5040.EMP.001 -- Install and remove temporary power to plant lighting transformers
12 IHP5021.EMP.009 -- Unit 2 battery AB individual cell charging
12 MHP5040.001.001 -- Temporary power and air supply to ice condenser

Calculations
ENSM990305AF Determine CCW Heat Exchanger UA Value During Recirculation Operation Revision 0
MD-12-CCW-001-N Component Cooling Water Heat Exchangers (1, 2HE-15E and 1,2HE-15W) Tube Minimum Wall Thickness Evaluation, Revision 0
MD-12-CCW-002-N, Mode 6 Heat Loads Impact Evaluation For Elevated Lake Water temperature, Revision 1
SD-991228-001 Stress Analysis of Essential Service Water Taps for Future Auxiliary Feed Pump Cubical Cooling System, Revision 3
00AE-G-0030 Reload Safety Evaluation Donald C. Cook Nuclear Plant Unit 2 Cycle 12 Revision 4, dated March 28, 2000
MD-12-HV-016-N Control Room Habitability Following R-22 Release from Chiller Units HV-ACR-1 and HV-ACR-2, Revision 0
FAI/99-27 Hydrogen Subcompartment Analyses for the D.C. Cook Unit 1 and 2 Containments Following DBA LOCAs, Revision 0

AEP-99-274 Transmittal of Post-LOCA Hydrogen Evaluation Report Revision 4 and SECL 99-002 Revision 3
MD-12-DG-004-N Diesel Fuel Oil Consumption Rate, Verification of DG Fuel Oil Storage and Day Tank Volumes, and Transfer Pump and Diesel Exhaust Line Sizing, Revision 0
1-2-UNC-056, Calc 1 DG Fuel Oil Storage Tank Level, Revision 0
MD-2-HV-011-N Donald C. Cook Unit 2 Containment Air Recirculation/Hydrogen Skimmer System Pressure Drop Calculation, Revision 1

Condition Reports

99-08545	99-09796	99-19705	99-19773
99-28370	99-24474	99-23555	99-21528
99-22552	99-23423	99-09964	99-09987
99-10084	99-10212	99-10448	99-10453
99-11224	99-11246	99-11271	99-11353
99-11448	99-12196	99-12345	99-12352
99-13730	99-13818	99-14400	00-03250
00-07021	00-07063	00-07141	00-07042
00-07026	99-26106	98-02078	99-14175
99-17286	99-18475	00-01269	99-28209
99-27438	99-29657	00-00759	99-28213
00-04895	00-02687	00-06011	00-06399
00-07026	99-26106	00-07051	00-07076
00-06780	00-06686	00-06745	99-29256
00-7071			

Deficiency Tags

032354	2-PI-323, 2W RHR Pump Suction Pressure Indicator Reads >60# (Greater than Scale) Gage is Isolated
032355	2-PI-313, 2E RHR Pump Suction Pressure Indicator Reads >60# (Greater than Scale) Gage is Isolated

Drawings
1-2-5197-7 Miscellaneous Tanks Revision 7.
Interim Drawings from 02 DCP-667 - INT-2-ESW-3,INT-2-ESW-85-DEMO, INT-2-ESW-85, INT-12-5249, INT-OP-2-5113
Interim Drawings from 02 LDCP-5480 - INT-2-ESW-85, INT-2-ESW-55, INT-2-ESW-62, INT-2-ESW-63, INT-0P-2-5113, INT-OP-2-5113A
1-5191-6 Transformer Decks Drains & Piping Diesel Fuel Oil Storage Tank & Piping Unit No. 1 Revision 6.
Drawing OP-2-5113-56 (ESW P&ID)
Drawing OP-2-5135-34 (CCW P&ID)
Drawing OP-2-5143-49 (RHR P&ID)
Drawing OP-2-5151B-53 (“AB” EDG P&ID)
Drawing OP-2-5151D-50 (“CD” EDG P&ID)
Drawing OP-2-5144-44 (CS P&ID)
Nuclear Document Information System Drawing Index, Dated 5/11/00, Unit 1 and 2 List of Controlled Drawings in the Control Rooms

Drawing OP-12-5126A	58	Plant Heating Boiler Fuel Oil Storage & Piping
Drawing OP-12-5146	40	Ice Condenser Configuration
Drawing OP-2-5104B	6	Composite Flow Diagram Chemical and Volume Control
OP-2-5105B-38	38	Flow Diagram Main Steam Unit No. 2

Drawing OP-2-5109D 1	0	Drip Piping
Drawing OP-2-5135	34	CCW [Component Cooling Water] pumps and CCW Heat Exchangers
Drawing OP-2-98044	35	4KV Diesel Generator 2CD ACB [Air Circuit Breaker]
Drawing OP-2-98229	1	Rod Control Logic Detail Diagrams Sheet 1 of 5
Drawing OP-298287A	16	emergency Core Cooling Residual Heat Removal Sheet 2
Drawing OP-2-98357	1	Rod Position Indication System Detailed Diagram
Drawing OP-2-98361	8	Solid State Reactor Protection & Safeguard System NIS [Nuclear Instrumentation System] Trips Train A
Drawing OP-2-98381	12	Solid State Protection & Safeguard System Primary Coolant Trips Train B
Drawing OP-2-98616	22	Reactor Coolant Annunciator Sheet 1
Drawing OP-2-99001	2	Reactor Coolant Delta T protection Channel 1
Drawing OP-2-99017	0	SG [Steam Generator] 4 Level Control
Drawing OP-2-99023	2	PRZ [Pressurizer] Pressure Control
Drawing OP-2-99026	1	Lower Containment Sump and Containment Level
Drawing OP-2-980761	1	Reactor Protection and Control Instrumentation DC [Direct Current] Power Supply Assemblies
Drawing OP-2-985413	1	Reactor Coolant Flow Protection Channel 3

Drawing OP-2-5113-56 (ESW Flow Diagram)

Assessments & Audits

RST-1999-001-NFG, Functional Area Assessment Report of the Nuclear Fuel Safety and Analysis Department (NFG), Revision 2, dated October 21, 1999
RST-1999-001-ENP, Plant Engineering Functional Area Self-Assessment
RST-1999-002-ENG, Functional Area Assessment Report of Design Engineering
SA-1999-004-NFG, Assessment Report of the AEP/Westinghouse Interface, dated September 23, 1999
SA-1999-008-NFG, Engineering Technical Issues Resolution, dated October 25, 1999.
PA-99-12/269, Design Control and Design Changes," Revision 0, and audit summary report dated June 23, 1999
PA-99-21, ASME Section XI Repairs/Replacement Program (PMI-5075) and audit summary report completed January 17, 2000
SR-99-0042, Preservation of Nuclear Safety Margins, dated January 19, 2000.
Performance Assurance Assessment Reports - October 1999 through April 2000
2000 Performance Assurance Annual Master Audit Plan
1999 Performance Assurance Annual Master Audit Plan
SA-19990OP-010S-008, Progress In Addressing Functional Area Assessments and Performance Assurance Findings and Recommendations for Restart
SA-2000-OPS-008, Annunciator Response Procedures
SA-2000-OPS, Shutdown Risk
SA-2000-SPS-009, Clearance Permit System

Job Orders

C0051359
C0054030
C0054009

Other Documents

Final Expanded System Readiness Report for Unit 2 ESW, (SRRB Mtg. # 00-428)
Final Expanded System Readiness Report for Unit 2 RHR, (SRRB Mtg. # 00-429)

Final Expanded System Readiness Report for Unit 2 EDG, (SRRB Mtg. # 00-397)
Final Expanded System Readiness Report for Unit 2 250 vDC, (SRRB Mtg. # 00-425)
Final Expanded System Readiness Report for Unit 2 120 vAC, (SRRB Mtg. # 00-407)
Final Expanded System Readiness Report for Unit 2 ESW (3/28/2000)
Final Expanded System Readiness Report for Unit 2 Containment (5/31/2000)
Initial Expanded System Readiness Report for Unit 2 CCW
Initial Expanded System Readiness Report for Unit 2 Containment
System Affirmation Report for Unit 2 ESW, (dated 4/5/00)
System Affirmation Report for Unit 2 RHR, (dated 4/5/00)
System Affirmation Report for Unit 2 EDG, (dated 3/31/00)
System Affirmation Report for Unit 2 250 vDC, (dated 4/2/00)
System Affirmation Report for Unit 2 120 vAC, (dated 3/24/00)
Operations Leadership Plan, Revision 12
Cook Nuclear Plant 10 CFR Part 50 Appendix R Safe Shutdown Capability Assessment
Response to NRC Information Notice 88-23, Supplement 5, Potential Gas Binding Of high Pressure SI Pumps During a LOCA.
Restart Action Packages 13, 14, and 15