May 7, 1998

EAs 98-150, 98-151, 98-152, 98-186

Mr. E. E. Fitzpatrick
Executive Vice President
Nuclear Generation Group
American Electric Power Company
500 Circle Drive
Buchanan, MI 49107-1395

SUBJECT: INSPECTION REPORT NO. 50-315/98004(DRS); 50-316/98004(DRS) AND CONFIRMATORY ACTION LETTER (CAL) NO. RIII-97-011 VALIDATION

Dear Mr. Fitzpatrick:

On January 27, 1998, the NRC completed an inspection at your D. C. Cook, Units 1 and 2 reactor facility. The purpose of the inspection was to validate the corrective actions you initiated to address significant safety issues revealed through the NRC Architect/Engineer (AE) inspection conducted in August and September 1997. Those corrective actions are documented in Confirmatory Action Letter (CAL) No. RIII-97-011. We determined that you made satisfactory progress on the CAL commitments, but also identified a number of apparent violations of NRC regulations. The results of the inspection are documented in the enclosed report.

The corrective action commitments documented in the CAL included actions to address specific AE inspection issues and the completion of a short term assessment to provide reasonable assurance that similar issues did not adversely impact the operability of other safety systems at the Cook nuclear facility. While a number of items will continue to be reviewed by our staff, the results of our inspection indicate that you have made satisfactory progress in completing the actions specified in the CAL. Specifically, our inspection confirmed: the completion of physical modifications to the Unit 1 and Unit 2 recirculation sumps and compressed air systems; the completion of calculations and analyses that demonstrate the capability to safely shutdown and cooldown the plant in the event of a design basis accident; the revision of emergency and operating procedures to address single failure criteria and other concerns; the submittal of Technical Specification amendment requests to your facility licenses; the conduct of training for your staff; and the adequate completion of a short term assessment to bound the impact of the engineering deficiencies on equipment operability. We discussed your actions taken in response to the CAL during a number of public meetings conducted in late 1997 through January 1998.

In the long term, your corrective action plans include implementation of an expanded instrument uncertainty program, which is scheduled to be completed by the end of 1998. Further, the inspectors considered your staff's efforts good in identifying other avenues that could bypass the design control process.

During review of engineering activities to asses the adequacy of your response to the CAL issues, twelve apparent violations were identified that could be considered for escalated enforcement action in accordance with the “General Statement of Policy and Procedure for NRC Enforcement Actions” (Enforcement Policy), NUREG-1600.

Three apparent violations of 10 CFR 50.59(b)(1) were identified concerning the failure to perform a safety evaluation for proposed changes to the plant design basis. These apparent violations resulted from your staff’s failure to recognize that the implemented changes constituted a change to the plant’s design basis. Additionally, seven apparent violations of 10 CFR 50.59(b)(1) were identified pertaining to inadequate safety evaluations. This issue is of particular concern as two of the deficient evaluations had recently been reviewed as part of your self-assessment and found acceptable by your staff.

One apparent violation of 10 CFR 50 Appendix B, Criterion III, “Design Control,” was identified pertaining to the failure to assure that the containment spray heat exchanger room heat gain calculation incorporated design input values that were consistent with the UFSAR. This was of concern because the nonconservative input values used allowed temperatures to exceed design for the containment spray heat exchanger room under accident conditions.

One apparent violation of 10 CFR Appendix B, Criterion XVI, “Corrective Action,” was identified concerning the failure to implement effective corrective actions. Specifically, corrective actions taken for previous occurrences did not prevent the installation of leak collection devices prior to performing an engineering review. In addition, our inspection identified weaknesses in your quality assurance (QA) organization audit methodology which contributed to your inability to self-identify AE inspection findings.

No Notice of Violation is presently being issued for these apparent violations. The actions necessary to correct the above apparent violations would be similar to planned or completed actions that you will discuss during the predecisional enforcement conference currently scheduled for May 20, 1998. Therefore, you will be advised by separate correspondence of the results of our deliberations on this matter. No response regarding these apparent violations is required at this time.

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.

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

Sincerely,

original /s/ J. A. Grobe

John A. Grobe, Director
Division of Reactor Safety

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

Enclosure: Inspection Report Nos. 50-315/98004(DRS);
50-316/98004(DRS)

cc w/encl: John Sampson, Site Vice
President
A. A. Blind, Vice President
Nuclear Engineering
Douglas Cooper, Plant Manager
Richard Whale, Michigan Public
Service Commission
Michigan Department of
Environmental Quality
Emergency Management
Division, MI Department
of State Police

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Division of Reactor Safety

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

Enclosure: Inspection Report Nos. 50-315/98004(DRS);
50-316/98004(DRS)

cc w/encl: John Sampson, Site Vice President
A. A. Blind, Vice President Nuclear Engineering
Douglas Cooper, Plant Manager
Richard Whale, Michigan Public Service Commission
Michigan Department of Environmental Quality
Emergency Management Division, MI Department of State Police

DOCUMENT NAME: G:\DRS\DCC98004.DRS (See Previous Concurrence)

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos.:	50-315; 50-316
License Nos.:	DPR-58; DPR-74
Report Nos.:	50-315/98004(DRS); 50-316/98004(DRS)
Licensee:	Indiana Michigan Power Company
Facility:	Donald C. Cook Nuclear Plant, Units 1 & 2
Location:	1 Cook Place Bridgman, MI 49106
Dates:	January 9 - 27, 1998
Inspectors:	David Butler, Team Leader Eric Duncan, Assistant Team Leader John Thompson, Lead 50.59 Inspector Robert Nujuch, Mechanical Design Inspector Dennis Vandeputte, Mechanical Design Inspector
Approved by:	Ronald Gardner, Chief, Engineering Specialists Branch 2 Division of Reactor Safety

EXECUTIVE SUMMARY

D. C. Cook Nuclear Plant, Units 1 & 2
NRC Inspection Report Nos. 50-315/98004 (DRS); 50-316/98004(DRS)

The purpose of this inspection was to validate actions that D. C. Cook took to address Confirmatory Action Letter (CAL) No. RIII-97-011 and to independently review additional calculations, modifications, and 50.59 screenings and safety evaluations. The inspectors concluded that the licensee had made substantial progress in addressing CAL requirements.

- The inspectors concluded that, overall, the licensee successfully completed job order activities and modifications to the Unit 1 and Unit 2 recirculation sump to re-install sump roof vent holes and add foreign material exclusion devices to prevent foreign material from entering the recirculation sump. However, the inspectors identified three (3) apparent violations of 10 CFR 50.59 where 10 CFR 50.59 screenings were not completed as required due to the licensee not recognizing that the plant design was being changed (Section C2.2).

- The inspectors concluded that the root causes applied to the CAL items and programmatic weaknesses, such as calculation control, were appropriate. However, AEP submittals to the NRC identified potential AEP to Westinghouse interface weaknesses (Section S2.1).

- Several calculations appeared to be obsolete but were still identified as valid calculations in the calculation index. A condition report was initiated to address calculation control issues (Section S2.2).

- The containment spray heat exchanger room heat gain calculation used design input values which were not consistent with the Updated Final Safety Analysis Report (UFSAR). This could result in the containment spray heat exchanger room temperature limits being exceeded during certain accident scenarios (Section S2.2.b.1.10).

- The licensee was adequately addressing other plant processes that could bypass the design control process. The review identified several processes, such as action requests, that had implemented changes to the plant (Section S2.3.b.3).

- The inspectors were concerned that safety evaluations continue to have deficiencies. Seven (7) apparent violations of 10 CFR 50.59 were identified. Two (2) of these examples were previously reviewed by AEP staff during the short term assessment reviews and were found to be acceptable. The inspectors concluded that weaknesses still exist in the safety evaluation program (Sections C2.2, S2.4 and S5.2).

- The licensee's 50.59 reviewer qualification training did not treat anticipated transients without scram and station blackout scenarios as accidents requiring the same level of review as UFSAR Chapter 14 accident scenarios. This was considered a weakness (Section S5.1).

- The licensee did not recognize that the refueling water storage tank (RWST) low level alarm setpoint change was a change to the plant. As a result, procedure specific safety evaluations were not performed (Section S5.2).

- The inspectors concluded that due to quality assurance (QA) organization audit methodology weaknesses, the licensee's QA organization did not identify the extent of the problems identified by the AE design inspection team (Section S7.1).

- Initial corrective actions implemented for the installation of leak collection devices appeared to be reasonable, however, leak collection devices were recently installed under the RWST overflow pipe without following the temporary modification procedure. It appeared that other contractor personnel were not properly informed that leak detection devices were considered a change to the plant. As such, the previous corrective actions did not preclude repetition (Section S7.2).

Report Details

I. Confirmatory Action Letter (CAL) Items

C2 Status of Facilities and Equipment

C2.1 CAL Item No. 1: "Recirculation Sump Inventory/Containment Dead Ended Compartments Issue"

a. Inspection Scope

The inspectors evaluated licensee documentation and actions to validate the following: *"Analyses will be performed to demonstrate that the recirculation sump level is adequate to prevent vortexing, or appropriate modifications will be made."* The following documents were reviewed:

- Calculation No. TH-97-12, dated October 22, 1997, "Containment Sump Level Following a Large Break LOCA"
- Calculation No. TH-97-13 (FAI/97-104), dated October 6, 1997, "Small Break LOCA Analyses for the D. C. Cook Units 1 and 2"
- Calculation No. TH-97-18, dated December 12, 1997, "Minimum Active Sump Water Level at the Initiation of Transfer to Recirculation"
- Calculation No. TH-97-19, dated January 7, 1998, "Effect of Additional Isolated Water Volumes on Sump Fill Calculations"
- Calculation No. TH-98-01, dated January 16, 1998, "Active Sump Inventory at Time of Peak Containment Pressure"

b. Observations and Findings

Large break LOCA calculation No. TH-97-12 appeared to use conservative and bounding assumptions. Two cases were analyzed: (1) loss of offsite power with one emergency diesel generator failure and the opposite emergency core cooling system (ECCS) and containment spray (CTS) train available (the current licensing basis case for calculating peak containment pressure - UFSAR Section 14.3.4); and (2) loss of offsite power with no single failures and both ECCS and CTS trains available. For both cases, the analysis results demonstrated that the active sump water level would exceed the minimum required elevation (EL) level of EL 602′-10″ at the time that switchover to recirculation occurred, and in the long term after the pipe annulus filled to EL 612′-0″ and overflowed to the active sump.

Small break LOCA calculation No. TH-97-13 (FAI/97-104) considered a spectrum of breaks from a ½ inch to 6 inch size. The 2 inch break was determined to be the most limiting with regard to water inventory in the containment sump. In all cases, the water level in the active containment sump was sufficient to support long term ECCS and CTS operation. A summary of the small break LOCA analyses was submitted to the NRC as Attachment 5 to AEP letter No. AEP:NRC:0900K, dated October 8, 1997, "Request for Exigent Technical Specification Amendment," Technical Specification 3/4.6.5, "Ice Weight and Surveillance Requirement," and Technical Specification 3/4.5.5, "Basis for Refueling Water Storage

Tank Change." This letter identified that post-LOCA containment water inventory analyses must take credit for additional water sources including ice condenser ice melt, accumulator inventory, and reactor coolant inventory release. The TS amendment requested that the required ice mass be increased to be consistent with the value used in analyses. The NRC granted the change request with the issuance of License Amendment Nos. 220 (Unit 1) and 204 (Unit 2).

One assumption inherent in both the large break and small break analyses was that the active sump and inactive sump (pipe annulus) volumes were completely separated (water was not exchanged between the two volumes) by the crane wall below EL 612′-0″. The licensee's safety evaluation, dated October 29, 1997, stated, in part, that holes (passageways) in the crane wall below elevation 602′-10″ had been plugged. A revision to the safety evaluation, dated December 22, 1997, subsequently identified that the crane wall penetration seals were not leak tight and would allow water to flow between the active and inactive sump volumes. The minimum calculated active sump level (EL 603′-7.5″) would still be above the minimum required 602′-10″ elevation at the time of switchover to cold leg recirculation.

The inspectors reviewed Calculation No. TH-97-18 which assessed the impact of water leakage through the crane wall penetrations. This calculation determined the maximum additional holdup volumes that could be allowed without the active sump level falling below EL 602′-10″ during ECCS and CTS recirculation phase operation. The derived allowable value was 5232 gallons. Calculation No. TH-97-19 was subsequently performed to determine additional holdup volumes inside containment resulting from water accumulation on top of the steam generators, the pressurizer enclosures, and within channels formed by the steam generator and reactor coolant pump structural steel supports. This volume was 5312 gallons for a small break LOCA. This quantity exceeded the 5232 gallon allowable value identified in calculation No. TH-97-18 (by 80 gallons), and indicates that the minimum calculated active sump level could fall slightly below EL 602′-10″. To address this result, the licensee stated in calculation No. TH-97-19 and in internal memo from R. Sartor to J. G. Feinstein, dated January 16, 1998, that the water volume added to containment by the spray additive system tank (minimum volume of 4000 gallons each per TS Section 3.6.2.2) could make up the 80 gallon shortfall. The inspectors questioned this approach since it would be contrary to the basis for issuance of License Amendment Nos. 220 (Unit 1) and 204 (Unit 2), and would also modify the basis for the existing spray additive tank volume requirements stated in TS Section 3.6.2.2.

In response, the licensee stated that the small shortfall in volume (80 gallons) was acceptable given conservatisms that exist in calculation Nos. TH-97-12, TH-97-13, TH-97-18, and TH-97-19. Though the licensee did not specifically identify these conservatisms, the inspectors confirmed that the following conservatisms existed:

- Equipment on the steam generator and pressurizer enclosure roofs was neglected (calculation No. TH-97-19, Sheet 4 of 11, Item 8). This would reduce the volume of water that could accumulate on the roofs.

- Active sump level calculations did not account for all equipment located in the sump spaces (internal memo from R. Sartor to ENSA calculation Nos. TH-97-12 and TH-97-13 Files. A larger equipment volume would result in higher sump level for a given volume of contained water.

  Based on the above conservatisms and the small size of the volume shortfall (80 gallons) relative to the total active containment sump volume (approximately 114,000 gallons of water at EL 602′-10″), the inspectors determined that the licensee's calculations provided reasonable assurance that the active containment sump level would be maintained above the minimum required 602′-10″ elevation for a wide spectrum of LOCA breaks without the spray additive system water volume.

  The licensee identified an additional calculation that credited the volume in the CTS spray additive system tank. Calculation No. TH-98-01 determined the containment active sump inventory at the time of peak containment pressure. This volume could impact the peak calculated containment pressure because the heat capacity of the sump water affects the containment spray water temperature. This impact was identified in original FSAR, Appendix N, "Ice Condenser Containment System Performance Evaluation Report," Question 23, dated July 1973. The licensee provided the sump inventory value calculated in TH-98-01 to Westinghouse for inclusion in their peak containment pressure evaluation. The inspectors did not disagree with the licensee's inclusion of the spray additive system tank volume in calculation
  No. TH-98-01 since that calculation was not related to ECCS/CST pump operability and would not alter the basis for the NRC's issuance of License Amendment Nos. 220 (Unit 1) and 204 (Unit 2).

c. <u>Conclusions</u>

The team concluded that analyses performed by the licensee were adequate and provided reasonable assurance that the containment recirculation sump water level will remain above the minimum level required to prevent vortexing (potential air entrainment) when the RHR and CTS pumps take suction from the recirculation sump. The analyses used suitably conservative assumptions and considered a wide spectrum of large and small break LOCA cases. This CAL Item is considered closed.

C2.2 <u>CAL Item No. 2</u>: "Recirculation Sump Venting Issue"

a. <u>Inspection Scope</u>

The inspectors evaluated licensee documentation and actions to validate the following: *"Venting will be re-installed in the recirculation cover. The design will incorporate foreign material exclusion requirements for the sump."* The following documents were reviewed:

Job Order Activity (JOA) Nos. C42318 (Unit 1), C42316 (Unit 2), C33231 (Unit 1), C35223 (Unit 2), C43199, and C43200

Design Change Deviation of Information Request (DCDIR) No. 09-25-0943-1

Design Change Package (DCP) No. 12-DCP-852, "Recirculation Sump Vent Holes in Unit 1 and Unit 2 Containment"

DCP No. 12-DCP-869, “Restore the Containment Sump Screens to the Original Design Drawing Configuration and Intent”

Design Drawing Nos. 1-2-3178 - Plan J-8 and Section J-7, and 1-2-3902 - Section F-6

Procedure No. 12MHP 4030.STP.008, “Inspection of Containment Sumps”

Procedure No. PMP 1040.SES.001, “Safety Evaluation Screening”

Procedure No. PPM 227400-STG-5400-03, “Design Change Packages”

Checklist No. 860540-ADM-5400-01, “Design Change Walkdown Checklist”

b. Observations and Findings

b.1 Background

The licensee documented in a 1978 letter to the NRC proposed modifications to the containment recirculation sump. These modifications were enhancements resulting from recommendations contained in a 1978 Alden Research Laboratory Report. In 1979 (Unit 2) and 1980 (Unit 1) the licensee completed modifications to the recirculation sumps to improve hydraulic performance and minimize the potential for vortex formation. As part of the modification package, ¾ inch holes were drilled into the containment recirculation sump roof to vent air that could be trapped beneath the roof.

In 1996, after questioning by the NRC resident inspector regarding the function of the holes (IR Nos. 50-315/96005; 50-316/96005), the licensee sealed the holes because they were not described in the UFSAR or indicated on plant flow drawings. The licensee did not verify the design requirements for the vent holes or identify that the ¾ inch holes deviated from the maximum ¼ inch containment recirculation sump foreign material exclusion (FME) requirement. However, the Alden test report did indicate that the sump would perform adequately without the vent holes.

b.2 Re-Installation of Sump Vents

The licensee re-drilled the ¾ inch sump vent holes that had previously been sealed. This activity was performed under a JOA since the licensee believed the work was to restore the sump back to its original design. The inspectors reviewed JOA Nos. C42318 (Unit 1) and C42316 (Unit 2). The licensee identified during the maintenance activity that the previously drilled holes were not in accordance with the design drawing. As discussed in DCDIR No. 09-25-0943-I, licensee personnel identified that the two vent holes in the southeast portion of the Unit 1 containment recirculation sump roof were only 8 inches center-to-center instead of 12 inches center-to-center as shown on design drawing No. 1-2-3178 - Plan J-8. To resolve this issue, the licensee accepted the holes as-is and revised the drawing to reflect the as-found configuration.

The inspectors determined that the method by which the re-drilling activity was conducted

was not consistent with procedure No. PMP 1040.SES.001. Procedure Step 4.1.1, stated, in part, that each proposed change to the Cook nuclear plant design shall be screened to determine the need for a safety evaluation as required by 10 CFR 50.59. A 50.59 screening had not been performed for re-drilling the holes. Failure to perform a safety evaluation for re-drilling the sump roof vent holes is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-01; EEI 50-316/98004-01).

b.3 Design Change to Add FME Devices

The licensee issued DCP No. 12-DCP-852 to address FME concerns pertaining to the containment recirculation sump roof vent holes. A fine mesh screen was installed over the vent holes to meet the ¼ inch FME requirement for the recirculation sump. The inspectors reviewed the design, and performed a modification walkdown on both units. No deficiencies specific to the modification design and installation were identified. However, the inspectors noted the following during the walkdown:

b.3.1 Design Change Walkdown Checklist Requirements Not Well Documented

Checklist No. 860540-ADM-5400-01 required during conceptual, pre-installation, and post-installation modification walkdowns, at a minimum, that the design change leader, the project engineer, and an operations team member participate in the walkdown. The inspectors reviewed the completed design change walkdown checklists associated with design change No. 12-DCP-852 and noted the following:

- The Unit 1 and Unit 2 conceptual design change walkdown did not include participants from project engineering or operations.
- The Unit 1 and Unit 2 pre-installation design change walkdown did not include a participant from operations.
- The Unit 1 and Unit 2 post-installation design change walkdown did not include a participant from operations.

This issue was discussed with licensee personnel who indicated that although personnel were not present during the formal walkdown as indicated on the various checklists, representatives from project engineering and operations reviewed and walked down the proposed design change. In addition, the licensee provided procedure No. PPM 227400-STG-5400-03 which gave additional design change walkdown direction. The inspectors determined that although the procedure provided some flexibility regarding the selection of personnel for design walkdowns, the exclusion of operations or engineering personnel was not explicitly discussed. At the end of the inspection, the licensee planned to revise the walkdown checklist to provide flexibility regarding design change walkdown participants. The inspectors determined that although an appropriate design review had been accomplished, licensee personnel responsible for the walkdown documentation should exercise more attention-to-detail to ensure formal walkdowns were appropriately documented.

b.3.2 Walkdown Materiel Condition Deficiencies

The inspectors conducted a Unit 1 walkdown of the containment recirculation and lower containment sumps. Overall, the inspectors determined that the sumps' materiel condition were acceptable. However, the following deficiencies were noted:

- Packing Leak

  The inspectors identified an active packing leak on lower containment sump pump (PP-38B) discharge shutoff valve No. 1-DR-114-2B. Specifically, a boric acid stalactite was hanging from the valve stem. In response, the licensee initiated action request (AR) No. A0155367. The identified leakage was determined to be about one drop per minute. The inspectors determined that although the licensee's response to write an AR was appropriate, the licensee should have previously identified this problem since extensive work had recently been completed in the vicinity of the valve.

- Missing Containment Recirculation Sump Support Nut

  The inspectors identified a missing ¾ inch nut on a Unit 1 containment recirculation sump screen support bracket. Licensee personnel provided an evaluation dated September 25, 1997, that dispositioned the as-found configuration as acceptable. In addition, the evaluation indicated that the existing ¾ inch anchor was bent downward to permit installation of ½ inch bolts for fastening the screen into position. The inspectors determined that the anchor bolt locations, including the location that was missing the nut, were described on design drawing Nos. 1-2-3178 - Section J-7 and 1-2-3902 - Section F-6. A 50.59 screening had not been performed for the missing nut. The licensee did not recognize that this was a change to the plant and had not performed a 50.59 screening for changing the plant design to delete this nut. Failure to perform a safety evaluation for the change to delete this nut is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-02).

b.3.3 Procedure and Documentation Deficiencies

The inspectors reviewed various licensee procedures completed as part of the containment sump modification work. The following procedure and documentation deficiencies were noted:

- The licensee monitored containment modification work to ensure foreign material was not introduced into the sump area. The inspectors reviewed procedure No. 12-MHP 4030.STP.008 and identified that although the sump inspection required that the sump screens be removed in order to gain access to the sump, the procedure did not verify that the screens were correctly re-installed. The inspectors determined that the procedure should contain steps verifying the as-left sump screen installation. This issue is an inspect

ion followup item (IFI 50-315/98004-03; IFI 50-316/98004-03) pending further NRC review.

- The inspectors noted during the review of design change No. 12-DCP-0852 that the screen size referred to in the 10 CFR 50.59 safety evaluation alternately referred to the sump vent hole screens as 1/4 inch mesh and 3/16 inch mesh, although 1/4 inch mesh was intended and installed. The inspectors determined that this oversight indicated a lack of attention-to-detail by the safety evaluation preparer.

b.3.4 Additional Containment Recirculation Sump Reviews

The inspectors identified the following Unit 1 and Unit 2 containment recirculation sump concerns:

- Containment Recirculation Sump Inlet Screen Repair

  The licensee identified during a 1995 inspection that the recirculation sump screens had gaps greater than the maximum ¼ inch allowable at their seating surface. The screens were repaired by adding stainless steel screening material around the sump screen edges. This work was completed for Unit 1 (JOA No. C33231) in October 1995, and Unit 2 (JOA No. C35223) in April 1996. The inspectors reviewed the work packages and determined that although the repair method to install the additional screening was discussed, the use of stainless steel screening material was not discussed in the 1995 repair evaluation. The inspectors noted that the original screen material was galvanized steel. A 50.59 screening had not been performed to address this change to the plant design even though engineering staff evaluations had determined that stainless steel was an acceptable material. Failure to perform a safety evaluation for changing screen materials is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-04; EEI 50-316/98004-04).

- Containment Recirculation Sump Inlet Screen Modification Review

  The licensee identified that the containment recirculation sump inlet grating was not configured in accordance with design drawings. Specifically, the installation details described coarse and fine mesh screens at the face of the containment recirculation sump. Design drawing No. 1-2-3902 called for galvanized wire mesh to be sandwiched between an inner and outer layer of galvanized grating. The drawing details also stipulated that the grating bars be fully aligned in both directions. In addition, UFSAR Section 6.2 described the recirculation sump as having coarse screen (gratings) and fine screen protection at the sump entry points. However, the licensee identified that the galvanized grating was of two different sizes and could not be fully aligned.

  The licensee processed JOA Nos. C43199 and C43200 to return the containment recirculation sump screen assemblies to their initial design. However, changes to the original design were made. This included the welding of the grating with the fine mesh screening material sandwiched in between rather than using stainless steel fasteners (original design), and reducing the individual sump screen “section” size. Licensee management decided to process a design change (12-DCP-869) due to the above sump screen changes differing from the original design drawing. The inspectors identified the following concerns with the design change:

  - The DCP abstract indicated that the DCP was an administrative convenience since no design change was taking place, but rather a

restoration of the recirculation sump screens to their original design. In addition, the abstract indicated that the DCP be prepared to better capture and document activities. The inspectors were concerned that the licensee did not initially recognize that the above changes were a change to the facility.

- The DCP abstract indicated that although the sump screen restoration had been started under JOA Nos. C43199 and C43200, the DCP was prepared after the restoration work had started. The inspectors determined that the Unit 1 recirculation sump work had been completed prior to DCP approval.

- The DCP safety evaluation discussed the use of stainless steel and the change in grating size, however, the safety evaluation did not discuss the welding of the coarse grating around the fine mesh or the reduced sump screen "section" size.

The inspectors determined that welding of the screens during the implementation of design change No. 12-DCP-869 on December 19, 1997, and the reduction in sump screen "section" size were changes to the facility that had not been evaluated in accordance with 10 CFR 50.59. Failure to perform a safety evaluation for the welding and reduction in sump screen size is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-05; EEI 50-316/98004-05).

c. Conclusions

The inspectors concluded that, overall, the licensee successfully completed the JOAs and modifications to the Unit 1 and Unit 2 recirculation sump to re-install sump roof vent holes and successfully added FME devices to prevent foreign material from entering the recirculation sump. This CAL Item is considered closed. However, the inspectors identified three (3) examples where 10 CFR 50.59 screenings were not performed as required by procedure No. PMP 1040.SES.001, and identified one (1) safety evaluation that did not address all changes to the facility.

C2.3 CAL Item No. 3: "Thirty-six Hour Cooldown with One Train of Cooling"

a. Inspection Scope

The inspectors evaluated licensee documentation and actions to validate the following: *"Analyses will be performed that will demonstrate the capability to cool down the units consistent with design basis requirements and necessary changes to procedures will be completed."* The following documents were reviewed:

Calculation No. ENSM970919AF, dated October 1, 1997, “CCW PP NPSH”

Calculation No. HX911210AF, dated October 7, 1997, “CCW LBPR Temperatures”

Calculation No. SAE/FSE-C-AEP/AMP-0102, dated September 16, 1997, “Cooldown Runs to Support Startup”

Calculation No. SAE/FSE-C-AEP/AMP-0085, dated August 15, 1997, “D. C. Cook Unit 2 Revised RHR Cooldown Analysis”

Calculation No. SAE/FSE-C-AEP/AMP-0086, Tabular Data

DCP No. 12-DCP-855, dated October 16,1997, “Change to the Donald C. Cook Final Safety Analysis Report (FSAR)”

Design Change Notice (DCN) No. 6944, dated January 23, 1998, “Safety Evaluation for UFSAR Changes to Add Maximum Flow Rates for Component Cooling Water Heat Exchanger and Letdown Heat Exchanger”

NSD-SAE-ESI-97-634 SECL-97-189, dated November 12, 1997, “FSAR Change to Support Increased CCW Temperature”

Procedure No. OHI-4013, dated September 10, 1997, “Operators: Authorities and Responsibilities”

Procedure No. 01-OHP 4021.001.004, dated November 17, 1997, “Plant Cooldown from Hot Standby to Cold Shutdown”

Procedure No. 01-OHP 4021.016.003, dated December 3, 1996, “Operation of the Component Cooling Water System during Reactor Startup and Normal Operation”

Procedure No. 01-OHP 4021.017.002, dated December 17, 1997, “Placing in Service the Residual Heat Removal System”

Procedure No. 12-OHP 4021.019.001, dated January 14,1998, “Operation of the Essential Service Water System”

CCW Pump Purchase Order No. 031-36110, dated January 29, 1971

Ingersoll Rand Pump Company Letter No. 14ALV, dated January 29, 1971, “CCW Pump Operating Temperature”

UFSAR Table 9.5-3, “Component Cooling System Component Design Data”

UFSAR Table 9.8-5, “Essential Service Water System Minimum Flow Requirements per Train”

Letter No. SAE-ESI-97-611, dated October 31, 1997, “Heat Exchanger Modeling Assumptions”

b. <u>Observations and Findings</u>

b.1 Westinghouse (W) Cooldown Analysis

Westinghouse calculation No. SAE/FSE-C-AEP/AMP-0102 was performed to address AE team concerns. The inspectors reviewed the tabulated input parameters and computer generated outputs to verify inputs were consistent with plant design and licensing basis. Calculation conclusions indicated that both single train and two train cooldown times could be met.

The current licensed power levels were 3250 and 3411 MWt for Unit 1 and Unit 2, respectively. The analysis was based on an ultimate heat sink (lake) temperature of 76˚F, and a reactor power level of 3411 MWt. Procedure Nos. OHI-4013 and 12-OHP 4021.019.001 provided operational guidance for monitoring essential service water (ESW) temperatures. These procedures identified that the plant design basis ultimate heat sink temperature limit was 76˚F. Procedure precautions and limitations indicated that the ESW system was inoperable at temperatures above 75.5˚F (based on instrument uncertainties). The inspectors determined that the analysis was consistent with current plant operating procedures. However, this analysis will have to be revisited to address the potential for increased ultimate heat sink temperatures during the summer.

The inspectors determined that the residual heat removal (RHR) and component cooling water (CCW) heat exchanger design flow inputs were consistent with their respective specification data sheet values and design values documented in UFSAR Table 9.5-3. Actual heat exchanger flow inputs were consistent with the design flows except for the CCW flow value (see Section b.2). The analysis was based on an ESW flow of 3.93 $X10^6$ lbs/hr compared to a specification data sheet design flow value of 4.75 $X10^6$ lbs/hr. This lower value corresponds to the licensing basis minimum ESW flow value documented in UFSAR Table 9.8-5. In addition, in response to an AE team heat exchanger modeling concern, Westinghouse letter No. NSD-SAE-ESI-97-611 confirmed that the CCW heat exchanger was modeled correctly as a two-pass tube and shell type heat exchanger in the cooldown analysis.

b.2 Design Change Package Review

Design Change Package No. 12-DCP-855 identified that the UFSAR did not address the maximum CCW heat exchanger outlet temperature (120˚F) that could be reached during plant cooldown. The DCP was prepared to support proposed UFSAR changes, to evaluate any required setpoint changes, to evaluate any design specification changes, and to evaluate any physical changes to the plant concerning CCW heat exchanger outlet temperature.

The “Component Cooling Water System 120˚F Compatibility Review” identified that the CCW pumps were originally procured with bearings designed for an operating temperature of 110˚F. This was identified in Ingersoll Rand Pump Company letter No. 14ALV. Ingersoll Rand Pump Company determined that the pumps were acceptable for operation with fluid temperatures up to 160˚F. The cooldown analysis indicated that the maximum temperature that the bearings would see was 156°F. In addition, the inspectors noted that the procured bearing design temperature was different than the design temperature identified in UFSAR Table 9.5-3. The Table identified the pump design temperature as 200˚F. The DCP evaluations did not identify and reconcile that the pump procurement documents and current evaluation results did not support the robust design temperature identified in the UFSAR. The licensee initiated condition report (CR) 98-0141, dated January 15, 1998, to document this discrepancy.

Procedure No. 01-OHP 4021.016.003, Sections 4.2 and 4.3 indicated that CCW flow through the CCW heat exchanger was controlled between 4000 and 9000 gpm. However, UFSAR Table 9.5-3 specified the CCW heat exchanger design flow as 4 $x10^6$ lbs/hr which corresponds to approximately 8000 gpm. The operating procedure permitted operation beyond the UFSAR design value without supporting documentation.

In response, the licensee initiated DCN No. 6944. The DCN indicated that the CCW heat exchanger could withstand an inlet and outlet bundle velocity up to 8 ft/sec. The maximum expected bundle velocity was 4.14 ft/sec at 9000 gpm. In addition, Tubular Exchangers Manufacturers Association Standards recommended that the heat exchanger tubes be supported at least every 52 inches. The CCW heat exchanger tubes were supported every 30 inches. This documentation supports that the CCW heat exchangers could withstand a 9000 gpm flow rate without a significant increase in flow induced vibration.

b.3 Calculation No. HXP911210AF

The inspectors identified the following minor discrepancies:

- Assumption 3 and 4 contradict each other in that assumption 3 addresses analysis of equipment not in service, while assumption 4 assumes all equipment in service.

- Piping segments 2-3, 1-2, and Z-1 were identified as CCW return piping from the RCP thermal barrier and were evaluated for a 25˚F temperature rise based on a design flow rate of 35 gpm through the thermal barrier. Past operating practices permitted the thermal barrier CCW flow to drop to 24 gpm. A safety evaluation determined that operation at reduced flow rates was acceptable. However, the reduction in flow would increase the thermal barrier outlet temperature from 145˚F to 157˚F.

- Piping Segment K-L did not address the mass flow rate contribution from the waste gas compressor returns.

- CCW return flow from the CCP mechanical seal cooler were analyzed for 10 gpm flow while the design input identified the flow requirement as 5 gpm.

- CCW flow to the spent fuel pool (SFP) heat exchanger was analyzed in accordance with assumption 4. This resulted in piping segment L-M temperature of 137.6˚F. If SFP cooling was not needed and the flow was isolated, then assumption 3 would be appropriate and segment L-M temperature would be approximately 145˚F. The licensee confirmed that procedure Nos. 01(02)-OHP 4021.001.004 and 12-OHP 4021.018.002 did not isolate CCW flow to the SFP during cooldown. When considering CCW flow demands of 5000 gpm for RHR, 3000 gpm for SFP, 1000 gpm for the letdown heat exchanger, and other CCW loads such as 500 gpm to the RCPs, 300 gpm to the containment penetrations, and 200 gpm to the seal water heat exchanger, the 9000 gpm CCW flow limit established in procedure No. 01-OHP 4021.016.003 would be exceeded. The inspectors believe isolation of CCW flow to the SFP would be required to achieve the necessary flow distributions and maintain equipment within their design parameters.

This is considered an inspection follow up item (IFI 50-315/98004-06; IFI 50-316/98004-06) pending NRC review of the licensee's resolution of these discrepancies.

b.4 CCW Temperature Increase Safety Evaluation

Safety Evaluation No. NSD-SAE-ESI-97-634 SECL-97-189 provided W calculation inputs to support single train CCW cooldown with CCW temperatures up to 120˚F. Within the safety evaluation, the letdown heat exchanger flow was assumed to increase to the maximum CCW letdown value of 1000 gpm. However, the letdown heat exchanger temperature control loop used an automatic controller set at 120°F. Since the 120˚F CCW supply could not provide a 120˚F letdown flow outlet temperature, the control loop would cause the CCW flow control valve to go full open. The control valve response was not addressed by the safety evaluation (see Section S2.4.b.5). Preliminarily, the licensee determined that the letdown heat exchanger CCW branch flow could go to 1400 gpm. This exceeds UFSAR Table 9.2-3 design specification value (492,000 lbs/hr was equivalent to 1000 gpm at operating conditions or 984 gpm at standard conditions) for the letdown heat exchanger. In response, the licensee performed DCN No. 6944. The DCN indicated that the letdown heat exchanger CCW flow could approach 1900 gpm without significant heat exchanger vibration.

b.5 Procedures

The inspectors reviewed procedure No. 01-OHP 4021.001.004. Section 4.1 verifies that SFP cooling and SFP CCW supply were aligned to Unit 2. However, the 36 hour cooldown analysis did not address the transfer of SFP heat loads to the opposite unit and did not address CCW flow distribution for the unit in a 36 hour cooldown. The potential existed for CCW pump run out due to the 3000 gpm SFP flow. The licensee indicated that CCW flow was controlled based on operator skills, training and knowledge of equipment limits. This should prevent CCW pump run out.

The inspectors reviewed procedure No. 01-OHP 4021.017.002. Step 4.72 verifies that initial CCW flow to the RHR heat exchanger in use was established between 4500 to 5500 gpm. The licensee confirmed that flow indicators CFI-419 and CFI-420 were used to establish this flow rate and estimated the flow channel uncertainty at 5000 gpm to be about +110 gpm / -224 gpm. Therefore, the flow rate through the RHR heat exchanger could be between 4276 to 5610 gpm compared to an analysis value of 5000 gpm. The licensee indicated that the instrument uncertainties would be accounted for during the long term expanded instrument uncertainty reviews.

c. Conclusions

The analysis and supporting documentation were generally acceptable. The inspectors concluded that the licensee had addressed this item in an acceptable manner. This CAL Item is considered closed. However, two instances where equipment and/or UFSAR design limits could be exceeded and one calculation that will require additional NRC review were identified.

C2.4 CAL Item No. 4: "ES-1.3 (Switchover to Recirculation Sump) Procedure"

a. Inspection Scope

The inspectors evaluated licensee documentation and actions to validate the following: *"Changes to the emergency procedure used for switchover of the emergency core cooling and containment spray pumps to the recirculation sump will be implemented. These changes will provide assurance there will be adequate sump volume, with*

proper consideration of instrument bias and single failure criteria." The following documents were reviewed:

Emergency operating procedure (EOP) Nos. 01(02)-OHP 4023.ES-1.3, dated January 3, 1998, "Transfer to Cold Leg Recirculation"

Supporting documentation identified in Attachment A.

b. Observations and Findings

b.1 Switchover to Recirculation

The licensee prepared and validated Revision 5 to procedure Nos. 01(02)-OHP 4023.ES-1.3. The inspectors reviewed the revised procedure and associated safety evaluations, dated October 29 and December 22, 1997.

Revision 4 to ES-1.3 aligned both trains of centrifugal charging (CCP) and safety injection (SI) to a single RHR pump (so-called piggyback operation) during switchover from injection to recirculation. In the event that this RHR pump failed to continue running (a single active failure not previously considered by the licensee), all high head injection capability would be lost as well as low head injection from the failed RHR pump. The switchover sequence was changed in Revision 5. When RWST water level reached 20%, the suctions for both RHR pumps and both containment spray (CTS) pumps would be switched to the recirculation sump. The high head systems would continue to take suction from the RWST. When RWST level reached 11%, then both trains of high head injection were switched to the discharge of their respective RHR pump. The following benefits were noted from these changes:

- More RWST water was transferred into the containment by the ECCS pumps prior to pump suction switchover to the recirculation sump. In Revision 4, switchover actions were initiated at an indicated RWST water level of 32% (the low level alarm point). In Revision 5, switchover actions start at an indicated RWST water level of 20%. This change was made possible, in part, by relocating the RWST level instrument taps from the RWST discharge pipe (ECCS suction) to a static RWST location. This eliminated the velocity head loss and friction loss biases from the level instruments.

- Licensee internal reviews, as well as external reviews by W and EPRI consultants, concluded that single active failures would not prevent successful switchover to the recirculation phase of operation.

- The possibility of ECCS flow interruption that existed with Revision 4 (see UFSAR Section 14.3.1 for a summary of the analysis previously performed for a 3 minute ECCS flow interruption) was eliminated. For all postulated single active failures, Revision 5 to ES-1.3 ensures that continuous ECCS injection flow will be provided at all times during the switchover evolution by one train of ECCS equipment.

- Revision 5 to ES-1.3 now confirms containment water level at 29% for normal containment and 37% for adverse containment. Both level confirmations include allowances for instrument uncertainties. With this water level in containment, the ECCS and CTS pumps would have adequate net positive suction head (NPSH), and vortexing (potential air entrainment) would not occur during the recirculation

phase. If this level could not be obtained, ES-1.3 would direct the operator to enter procedure Nos. 01(02)-OHP 4023.ECA-1.1, "Loss of Emergency Coolant Recirculation," and the switchover to recirculation would not proceed. This basis was consistent with the Westinghouse Emergency Response Guidelines (ERGs).

The inspectors reviewed procedure No. ES-1.3 to ensure the CCW system was delivering full flow (5000 gpm) to the RHR heat exchangers prior to switchover to recirculation. In Revision 4, this procedural action had been delayed until after switchover to recirculation had been completed. This condition was contrary to UFSAR Chapter 14 safety analysis assumptions. The safety analysis assumed that full CCW flow to the RHR heat exchangers existed as soon as switchover to recirculation was initiated. The inspectors asked the licensee if a historic operability review had been performed for past ES-1.3 procedure revisions. In response, The licensee indicated that W was currently evaluating this item for historic operability. This is considered an unresolved item (URI 50-315/98004-07; URI 50-316/98004-07) pending NRC review of the historic operability determination.

b.2 RWST Level Tap Relocation

The inspectors walked down the RWST water level instrument tap relocation modification and determined that the installation was acceptable.

b.3 Peak Containment Pressure and Long Term Post-LOCA Core Subcriticality Evaluations

The Safety Evaluation for Revision 5 to ES-1.3 identified other W analyses impacted by the sump inventory calculations. This included the peak containment pressure and long-term core subcriticality confirmation following a LOCA. Westinghouse evaluated the sump inventory impact, and determined that the peak containment pressure and long-term subcriticality results were acceptable. However, these result were preliminary and had not been provided to AEP as a formal document. This is considered an inspection follow up item (IFI 50-315/98004-08; IFI 50-316/98004-08) pending NRC review of the approved documentation.

c. Conclusions

The inspectors concluded that the changes made to ES-1.3 for ECCS and CTS switchover to the containment recirculation sump adequately addressed the single failure vulnerability, and that the revised switchover procedure was consistent with the assumptions made in the UFSAR. This CAL Item is considered closed.

C2.5 CAL Item No. 5: "Compressed Air Overpressure Issue"

a. Inspection Scope

The inspectors evaluated licensee documentation and actions to validate the following: *"Overpressure protection will be provided downstream of the 20 psig, 50 psig, and 85 psig control air regulators to mitigate the effects of a postulated failed regulator."* The following documents were reviewed:

DCP No. 12-DCP-584, "Safety Relief Valves for Control Air System and Changes to the Control Air to the AES and AFX Dampers"

b. Observations and Findings

b.1 Unit 1 and 2 Turbine and Auxiliary Building Control Air Supply

The licensee installed two safety-relief valves at the discharge of each 20 psig, 50 psig, and 85 psig control air regulator. In addition, the licensee installed check valves downstream of the safety-relief valves to prevent back pressure from an opened safety-relief valve from impacting other parallel regulated control air lines. Finally, in order to limit the air flow rate through the headers downstream of the postulated failed regulator, each header was provided with a flow restricting orifice upstream of the pressure regulator. The inspectors reviewed and walked down the modification. No discrepancies were identified.

b.2 Unit 1 and 2 Containment Control Air Supply

The licensee installed two safety-relief valves (redundant to each other) at the ends of the 50 psig and 85 psig headers inside containment. During the inspection, the licensee identified that the stainless steel tubing used to connect the control air header safety-relief valves to the 50 psig and 85 psig headers were undersized. Subsequently, the licensee determined that this could result in excessive pressure accumulation on the affected headers should an overpressure condition occur. Following the NRC exit meeting on January 27, 1998, the licensee relocated the Unit 1 safety-relief valves to just downstream of the control air regulators. The Unit 2 modifications were currently in progress.

c. Conclusions

The inspectors concluded that licensee actions to install safety-relief valves on the control air headers were appropriate. This CAL Item is considered closed.

C2.6 CAL Item No. 6: "Residual Heat Removal (RHR) Suction Valve Interlock Issue"

a. Inspection Scope

The inspectors evaluated licensee documentation and actions to validate the following: *"A Technical Specification change to allow operation in Mode 4 with the RHR suction valves open and power removed is being processed. Approval of this change by the NRC will be required prior to restart."* The following documents were reviewed:

Condition Report No. 97-2454

Procedure Nos. 01(02)-OHP 4021.017.002, "Placing in Service the Residual Heat Removal System"

Technical Specification (TS) Amendment Nos. 219 (Unit 1) and 203 (Unit 2)

b. Observations and Findings

The licensee identified on September 11, 1997, that a discrepancy existed between the UFSAR and current operating practices for the automatic RHR suction valve interlock when RHR was aligned to the reactor coolant system (RCS) during shutdown cooling. At the time of discovery, operating procedure Nos. 01(02)-OHP 4021.017.002, allowed RHR suction valves IMO-128 and ICM-129 to be opened and de-powered when RCS pressure was below the interlock setpoint. However, UFSAR Section 9.3.2, stated, "The [RHR] suction line valves are interlocked through separate channels of the reactor coolant system

pressure signals to provide automatic closure of both valves whenever the RCS pressure exceeds design pressure of the RHR system. In addition, both valves are interlocked to prevent inadvertent opening under such conditions," and "When the RCS is open to the atmosphere, power to both suction isolation valves (IMO-128 and ICM-129) is locked out to prevent inadvertent closure of the valves and the potential loss of RHR." When power was removed to the suction valves, the valves were no longer capable of automatic closure for a high RCS pressure condition. Also at the time of discovery, TS 4.5.2.d.1 required, in Modes 1, 2, and 3, "Verifying automatic isolation and interlock action of the RHR system from the Reactor Coolant System when the Reactor Coolant System pressure is above 600 psig." The automatic isolation and interlock capability was appropriately surveillance tested. However, TS 4.5.3.1 required that if Tave was less than 350°F, "The ECCS subsystem shall be demonstrated OPERABLE per the applicable Surveillance Requirements (SRs) of 4.5.2," which would include TS 4.5.2.d.1. Therefore, the automatic isolation function of these valves would have to be operable. The licensee provided in the TS amendment submittals that the automatic isolation interlock was originally intended to prevent an intersystem loss of coolant accident (LOCA) from an RCS high pressure condition when the RHR system was aligned for shutdown cooling. Since June 1980, the licensee has defeated the automatic closure interlock on both units any time the RHR system was operating in it's normal configuration. This was done to prevent shutdown cooling loss due to an inadvertent closure of these valves and to maintain low temperature overpressure protection (LTOP).

An amendment to TS 4.5.6.d.1 was applied for and granted by the NRC on December 10, 1997, for both units. The new TSs now read as "Verifying the automatic interlock action to prevent opening of the suction of the RHR system from the Reactor Coolant System when the Reactor Coolant System pressure is above 600 psig." This brings the TS in-line with NRC Bulletin 80-12, "Decay Heat Removal System Operability," and with NUREG-1431, Revision 1, "Standard Technical Specifications Westinghouse Plants." The licensee plans to change UFSAR Section 9.3.2 during the next annual update. The update should replace "provide automatic closure" with "prevent inadvertent opening" of both valves whenever the RCS pressure exceeds the RHR system design pressure. This will bring the UFSAR in agreement with the TS wording.

c. Conclusions

The inspectors reviewed the above documentation and concluded that the TS amendment requirements had been implemented in an acceptable manner. In addition, operating procedures were revised as required to accurately reflect the design basis. This CAL Item is considered closed.

C2.7 CAL Item No. 7: "Fibrous Material in Containment"

a. Inspection Scope

The inspectors evaluated licensee documentation and actions to validate the following: *"Removal of fibrous material from containment that could clog the recirculation sump will be completed."*

b. Observations and Findings

The licensee removed over 13,095 pounds of various materials from both containments, including insulation, coatings (paint), labels, rust, tape, HEPA filters, granular charcoal, and

other foreign material. In Unit 1, the licensee selectively removed paint on the lower containment floor down to the base concrete and reapplied new coatings. Equipment such as welding machines, vacuums and man-lifts used during outages were also removed. Procedures, instructions, and specifications were being revised to protect the recirculation sump from sources of material that could plug it. A formal Containment Sump Operability Determination was placed on the docket during the January 8, 1998, public meeting. NRC review of the operability determination found it to be acceptable. Many of the licensee's corrective actions were observed by the inspectors. Additional information on the fibrous material concern may be found in NRC inspection report Nos. 50-315/97017; 50-316/97017.

c. Conclusions

The inspectors concluded that the licensee had improved the containment sump materiel condition in an acceptable manner. This CAL Item is considered closed.

C2.8 CAL Item No. 8: "Refueling Water Storage Tank (RWST) Mini-flow Recirculation Lines"

a. Inspection Scope

The inspectors evaluated licensee documentation and actions to validate the following: *"Only two of six mini-flow recirculation line valves have leakage verification tests. Justification will be provided that the total leakage for the six valves is less that 10 gpm to ensure that Part 100 dose rates are not exceeded if containment sump water were to leak back to the RWST during a design basis accident."* The following documents were reviewed:

Information Notice No. 91-56, "Potential Radioactive Leakage to Tanks Vented to Atmosphere"

Licensee Assessment No. 960308.001

Procedure No. 12-EHP SP-088, "RWST Isolation Valve Leak Test"

b. Observations and Findings

Fluid leakage past the valves that isolate the ECCS recirculation flow path from the RWST (vented to atmosphere) could result in an unfiltered and unmonitored release to the environment, and contribute to the offsite and control room dose. This issue was provided to the industry in Information Notice No. 91-56. The AE team reviewed assessment No. 960308.001 and noted that certain valves identified as potential leakage paths were not in the leak testing program.

The licensee identified eight valves in four flow paths that provided an isolation boundary back to the RWST. Of the eight valves, two were on the SI minimum flow line and were controlled as category "A" valves within the inservice testing (IST) program. A third valve, the RHR return valve to the RWST, was also periodically leak tested. The five remaining valves were not in a testing program. These included the SI and CCP suction valves. The licensee developed and performed surveillance procedure No. 12-EHP-SP-088 on September 29, 1997, for Unit 1 and on September 27, 1997, for Unit 2. The total measured leakage was 0.003 gpm for Unit 1 and 0.482 gpm for Unit 2. Both tests satisfied the 10

gpm allowable limit.

A meeting was held on October 9, 1997, between the NRC and the licensee to determine valve testing requirements. The meeting determined that the previous IST Category "B" categorization for these valves was correct and that enhanced seat leakage testing could be accomplished within the system integrity program. Subsequently, the licensee indicated that their 3rd-10 year interval IST program plan would collectively leak test these valves every refueling outage to ensure that backseat leakage remained less than 10 gpm.

c. Conclusions

The inspectors concluded that the valves were appropriately classified in the IST program and that their total back leakage met the 10 gpm allowable limit. This CAL Item is considered closed.

C2.9 CAL Item No. 9: "Instrument Uncertainties Incorporated into Procedures and Analyses"

a. Inspection Scope

The inspectors evaluated licensee documentation and actions to validate the following: *"Emergency procedures and other important-to-safety procedures, calculations, or analyses will be reviewed to account for instrument uncertainties."* The following documents were reviewed:

Procedure No. PMP 5030.001.002, "Control of Critical Parameters"

Engineering Guide No. IC-004, "Instrument Setpoint/Uncertainty"

Cook Plant Critical Parameters List

Procedure Nos. 01(02)-OHP 4030.STP.030, "Daily and Shift Surveillance Checks"

Procedure Nos. 01(02)-OHP 4023.ES-1.3, "Transfer to Cold Leg Recirculation"

b. Observations and Findings

The licensee implemented an expanded instrument uncertainty program. Process parameters used in emergency procedures, other important-to-safety procedures, and analyses were to be reviewed to ensure instrument loop uncertainties were accounted for. This program was scheduled for completion in 1998. Following the AE inspection, the licensee completed instrument tap reviews on the refueling water storage tank and other critical storage tanks to identify if any other velocity-induced errors existed. No other significant bias errors were identified. Uncertainty calculations were generated or revised as required to provide the basis for quantitative data collection documented in operations department shiftly surveillance proced

ures. In additio n, a critical param eter list was develo ped contain ing param eters related to TS compli ance or operabi lity of TS system s.

The inspectors reviewed IC-004 and validated that process flow velocity effects had been appropriately characterized as a flow induced bias in the design guide. In addition, the critical parameter list was reviewed and the inspectors determined that the list was comprehensive. Many of the critical parameters were listed in procedure Nos. 01(02)-OHP 4030.STP.030. The inspectors validated that appropriate uncertainty values had been applied to the procedure critical parameters.

c. Conclusions

The inspectors concluded that the licensee was addressing instrument loop uncertainties in an acceptable manner. In addition, appropriate RWST level instrument uncertainties had been incorporated in procedure No. ES-1.3 (see CAL Item No. 4). This CAL Item is considered closed.

II. Short Term Assessment

S2 Support of Facilities and Equipment

S2.1 Root Cause Determination

a. Inspection Scope

The inspectors evaluated the licensee's root cause assessment for the following CAL Items.

b. Observations and Findings

b.1 CAL Item No. 1

The licensee identified the following as primary root causes:

- A lack of thorough engineering review,
- inadequate design control during initial plant design, and
- improper implementation of well defined design expectations.

The inspectors agree with the licensee's root cause assessment. However, the inspectors believe that additional emphasis was warranted by AEP in recognizing design deviations made by AEP from the original W design requirements. Compounding this issue was a lack of clear communication between AEP and W with regard to who had the responsibility to ensure that appropriate design, calculational, and operating input parameters were clearly accounted for when deviations were made.

b.2 CAL Item No. 2

The licensee identified the following as primary root causes:

- FME requirements were not addressed,
- design change package was not properly incorporated into the design documentation, and
- the design and licensing basis could not be retrieved in a timely manner.

The inspectors agree with the licensee's root cause assessment. However, the inspectors believe that a lack of understanding of what constitutes a design change stemming from not fully understanding the plant's design and licensing basis influenced this item.

b.3 CAL Item No. 3

The licensee identified the following primary root causes:

- Design parameters for all system conditions were not described in the UFSAR, and
- analysis used an unverified (an incorrect) assumption of heat exchanger type.

The inspectors believe that a combination of root causes from CAL Item Nos. 1 and 2 were applicable to this item. However, the inspectors believe that additional emphasis was warranted by AEP in recognizing design deviations made by AEP from the original W design requirements. Compounding this issue was a lack of clear communication between AEP and W with regard to who had the responsibility to ensure that appropriate design, calculational, and operating input parameters were clearly accounted for when deviations were made.

b.4 CAL Item No. 4

The licensee identified the following primary root causes:

- Lack of consideration of Bernoulli effect on level instrumentation, and
- incorrect application of single failure criteria.

The inspectors agree with the licensee's root cause assessment. However, the inspectors believe that the failure to recognize the importance and potential ramifications for deviating

from the original W requirements, and the failure to fully recognize the interrelationship between the recirculation sump and RWST water inventory were major contributors to the root causes.

b.5 CAL Item No. 5

The licensee identified the following primary root cause:

- Failure to identify a non-safety system failure mode that could impact safety system components.

The inspectors agree with the licensee's root cause assessment. However, the inspectors believe that the licensee identified root cause does not fully account for how the plant was originally designed. For example, the D. C. Cook compressed air system design uses a single main air header to supply other air subheaders which interface with redundant safety related components. This design was used by AEP in their fossil units and was advantageous from an economics and/or design simplicity standpoint. However, subheader location in this design was significantly upstream from the point where an engineer would typically focus their failure modes and effects analysis. In this case, the analysis assessed the loss of air at the valve actuator and did not identify a subheader regulator high pressure failure.

b.6 CAL Item No. 6

The licensee identified the following primary root cause:

- Processes in place (at the time) did not emphasize the UFSAR, resulting in an inadequate safety review.

The inspectors agree with the licensee's root cause assessment. However, the inspectors believe AEP did not consider the UFSAR to be a design basis document which contributed to the rationale for why the UFSAR was not emphasized when changes to the facility were made.

b.7 CAL Item No. 7

The licensee identified the following primary root causes:

- Lack of procedures for implementing an insulation specification, and
- failure to address sump-plugging potential of fibrous insulation material installed in containment.

The inspectors agree with the licensee's root cause assessment. In addition, AEP's methods for reviewing and evaluating industry experience may have contributed to this Item.

b.8 CAL Item No. 8

The licensee identified the following primary root cause:

- Failure to ensure that plant equipment met assumptions incorporated in licensing basis calculations.

The inspectors agree with the licensee's root cause assessment.

c. Conclusions

In general, the inspectors concluded that the root causes applied to the CAL items and programmatic weaknesses, such as calculation control, were appropriate. However, AEP submittals to the NRC identified potential AEP to W interface weaknesses, such as W using an incorrect heat exchanger type in analyses and AEP choosing to locate the RWST level instrument tap on the tank discharge pipe, which initially, added an unidentified flow bias error to the level measurement that could have affected swithchover to recirculation. The inspectors believe the AEP to W interface was also a root cause to several of the CAL Items. Additional reviews may be warranted in AEP designs that deviated from W recommendations. This is considered an open item (50-315/98004-17; 50-316/98004-17) pending NRC review of AEP deviations from W design recommendations.

S2.2 Calculations

a. Inspection Scope

The licensee reviewed about 191 calculations and identified some administrative and minor technical concerns, but in no cases did the concerns affect component or system operability. The inspectors reviewed a sample of calculations associated with the auxiliary feedwater (AFW) system and containment spray (CTS) system. The sample was selected from the calculation index with an emphasis on system performance type calculations. The review focused primarily on inputs, assumptions, methodology, and reasonableness of results and conclusions presented in the calculations.

b. Observations and Findings

b.1 Mechanical Calculation Reviews

b.1.1 HXP721130FK-1 - dated November 30, 1972, "Condensate Storage Tank Level"

The basis for certain assumptions were not stated (for example, 60 gallons per MWt rating of the reactor), and the reactor MWt rating used (3391) was less than the licensed Unit 2 power level of 3411 MWt. The calculated value for required water volume was 203,560 gallons. However, the current TS value for minimum CST volume was 175,000 gallons (TS Section 3.7.1.3). Thus, the basis for minimum CST volume may be different than stated in this calculation. The inspectors believe that this calculation was probably obsolete even though it still appeared as a valid calculation in the calculation index. The licensee had initiated a condition report to review the calculation control process.

b.1.2 HXP721130FK-2 - dated November 30, 1972, "Aux. Feed Pump $NPSH_a$"

The calculational method used was appropriate, however, no references were provided for inputs and assumptions. In addition, the assumed flow rates did not account for possible pump runout if a steam generator depressurized for a postulated feedwater line break. The calculation used a 100°F CST water temperature whereas UFSAR Table 10.5-1 showed 120°F. The UFSAR change to 120°F was made in 1991, however, this difference had no

significant impact on the calculated NPSH. The inspectors believe that this calculation was probably obsolete even though it still appeared as a valid calculation in the calculation index. The licensee had initiated a condition report to review the calculation control process.

b.1.3 HXP740226FK - dated February 26, 1974, “NPSH Requirements”

This calculation used a computer program to determine the AFW system flow balance. The minimum CST level at EL 611′-3″ appeared conservative since the bottom of the outlet pipe was at EL 609′-9″(per calc. HXP740715FK-1). In addition, the calculation used a CST water temperature of 100°F whereas current UFSAR Table 10.5-1 showed 120°F. However, this difference had no significant impact on the calculated NPSH. Results appear reasonable for the stated inputs and assumptions. The available NPSH was adequate for the system flow rates calculated in more recent calculation Nos. HXP910619AF and NEMH930601AF.

b.1.4 ENSM740501FK1 - dated May 11, 1974, “Aux. Feedwater Pumps – Tech. Specs”

This calculation provided no references for inputs and assumptions, and contained a licensee identified mathematical error. However, the error had no significant impact on the calculation results. The inspectors believe that this calculation was probably obsolete even though it still appeared as a valid calculation in the calculation index. Acceptable AFW pump operation including pump degradation was recently evaluated in calculation No. NEMH930601AF.

b.1.5 HXP740715FK-1 - dated July 15, 1974, “Condensate Storage Tank Usable Volume”

This calculation provided no references for inputs and assumptions, and assumed that the CST volume was usable to the bottom of the tank outlet pipe (EL 609′-9″). The inspectors were concerned that vortexing could occur at the tank outlet pipe. However, the calculated usable volume was 369,000 gallons which far exceeded Technical Specification 3.7.1.3 requirement of 175,000 gallons.

b.1.6 HXP910619AF - dated August 13, 1991, “AFW System Flows”

This calculation was provided with a clear purpose, method, and conclusion. It used a computer program to determine the AFW system flow balance for various postulated accident conditions. The calculation determined AFW inputs for W analyses summarized in UFSAR Section 14.2.8, “Main Feedline Break.” The inspectors confirmed that the W analyses were performed using conservative assumptions.

b.1.7 NEMH930601AF - dated June 21, 1993, “Percent Pump Degradation”

This calculation was provided with a clear purpose, method, and conclusion. It used a computer program to determine the AFW system flow balance for main feedline break conditions. The inspectors confirmed that the amount of pump degradation allowed met the main feedline break analysis assumptions.

b.1.8 ENSM740604FK - dated June 4, 1974, “CTS Pump NPSH - CTN Sump at 190°F”

The inspectors noted that different sump levels were used in the calculation. A level of 595'-5" and a UFSAR sump level of 612'-0" were used. However, they were not consistent

with the 602'-10" minimum level considered for ECCS pump vortex (potential air entrainment) prevention. Condition report No. 97-2934 had been initiated to document this discrepancy. The CR indicated that this calculation had been superseded by calculation No. ENSM970128AF, dated July 15, 1997. The newer calculation was considered the calculation of record. The licensee had initiated a condition report to review the calculation control process.

b.1.9 HXP921021JEW - dated December 17, 1992, “CTS Pump Operation”

Inspector observations were answered in an acceptable manner. The calculational method and conclusion were appropriate.

b.1.10 DCCHV12AE06-N - dated June 3, 1992, “Heat Gain Calculation - AES System”

The inspectors noted the following:

- The containment spray heat exchanger room, containment spray pump room, safety injection pump room and centrifugal charging pump rooms were evaluated at 125˚F for heat transmission through wall to adjacent rooms at 104˚F. This approach did not consider heat loads in adjacent rooms, and that the heat sink may not be available due to simultaneous operation of other accident mitigation

equipment. For example, one CCP room has the SI pump room, a pipe chase, the other CCP room, and a hallway surrounding it.

In response, the licensee confirmed that the heat transmission to adjacent areas through the four walls with an ambient temperature of 104˚F had been considered. Subsequently, the inspectors determined that only the hallway wall should have been considered. The licensee initiated a condition report to evaluate this condition.

- The containment spray heat exchanger room heat load determination was based on a 3300 gpm ESW flow rate with a 76˚F inlet and 142˚F outlet temperature, and a 170˚F sump inlet temperature. However, UFSAR Table 9.8-5, "Essential Service Water System Minimum Flow Requirements per Train," Note 4, indicated that a 2400 gpm ESW flow for containment spray cooling was acceptable. In addition, UFSAR Section 6.3.2, "System Design" for the containment spray system indicated the Unit 1 sump temperature was 160˚F and Unit 2 sump temperature was 190˚F. This calculation was applicable to both units.

In response, the licensee used the bounding ESW flow (2400 gpm) and Unit 2 sump temperature (190°F) to determine the final room ambient temperature. The licensee determined that the final room ambient temperature would go to 142.3˚F which exceeds the current design value of 125˚F. The licensee initiated a condition report to evaluate the use of incorrect design inputs.

The licensee did not identify to the inspectors any safety related equipment that could be adversely affected by the increased room temperature. However, the failure to verify or check the adequacy of the design inputs in calculation No. DCCHV12AE06-N is considered an apparent violation of 10 CFR 50, Appendix B, Criterion III (EEI 50-315/98004-09; EEI 50-316/98004-09).

b.2 Instrument and Control Calculation Reviews

2-WSI-07A, dated July 29, 1993, "Loop Uncertainty/Setpoint Calculation for Containment Spray Pump Discharge Pressure"

2-WSI-07B, dated July 29,1993, "Loop Uncertainty/Setpoint Calculation for Containment Spray Heat Exchanger Temperature"

2-WSI-07C, dated July 29, 1993, "Loop Uncertainty/Setpoint Calculation for Containment Spray Flow from the RHR Heat Exchangers"

The inspectors identified no concerns with the above instrument loop uncertainty calculations.

b.3 Net Positive Suction Head (NPSH) Calculation Reviews

During the AE inspection and this inspection, NPSH calculations for the residual heat removal (RHR) system pumps, the auxiliary feedwater (AFW) system pumps, and the containment spray (CTS) pumps were reviewed. The inspectors verified as many design inputs as possible during the calculation reviews. The NPSH calculations appeared to consider appropriately conservative values for pump suction source water levels, system temperatures, and system flow rates. The inspectors determined that the calculation

results adequately demonstrated that the available NPSH exceeded the required NPSH for the RHR, AFW, and CTS pumps. In addition, the licensee provided the safety injection (SI) pump NPSH calculations. The inspectors did not have time to verify the design inputs but only to verify that the conclusions were acceptable. The SI calculations (HXP840130JEW and ENSM970128AF) likewise indicated that sufficient NPSH existed for both pumps.

c. Conclusions

The inspectors came to the following conclusions:

- Older calculations (early 1970s vintage) were not as thorough as more recent calculations and provided little or no basis for inputs and assumptions, however, the calculations appeared to satisfy their intended purpose.

- Several calculations appeared to be obsolete, however, they were still identified as valid calculations in the calculation index. The licensee initiated CR 97-2525 to address calculation control issues.

- Several minor administrative and technical concerns were identified, however, none of the concerns appeared to have any impact on the calculation results or alter the conclusions of the calculations except for the CTS heat gain calculation.

One calculation reviewed was found to be inadequate and violated NRC requirements. The CTS heat exchanger room heat gain calculation used design input values which were not consistent with the UFSAR. This could result in the CTS heat exchanger room temperature limits being exceeded during certain accident scenarios.

S2.3 Design Change Process

a. Inspection Scope

The inspectors reviewed several modifications including their scope/description, safety review memo/evaluation, applicable calculations, and affected drawings. In addition, avenues that could bypass the design control process, such as the Action Request process, were reviewed. The following requests-for-changes (RFCs), design change packages (DCP) and

documents were reviewed:

DCP No. 01-DCP-0006, Modify Plant Process Computer (PPC) for Blackout Testing

RFC No. DC-12-1729, Install an Overvoltage Alarm on the Output of each Battery

RFC No. DC-12-1798, Change TDAFW Pump Trip Latch Mechanism Trip Mode

RFC No. DC-12-1984, Accumulator Tank Level Transmitter Range Change

RFC No. DC-12-2436, Turbine Driven Auxiliary Feedpumps Modification

RFC No. DC-12-2883, D/G Room Supplemental Ventilation for Electrical Panel No. 2

Memo, M. S. Ackerman to RFC DC-12-2883 Packet, Donald C. Cook Nuclear Plant Unit Nos. 1 and 2, Safety Review Memorandum: Addition of Supplemental Equipment to Electrical Equipment in Diesel Generator Rooms; RFC DC-12-2883, June 17, 1986

Memo, D. B. Black to RFC DC-12-2883, Rev. 1 Packet, Cook Nuclear Plant Diesel Engine Room Ventilation Alarm Changes, April 10, 1989

Memo, G. M. Gurican to RFC Packet (RFCDL Ref. No. 5), Safety Review of RFC DC-12-2436, December 6, 1979

b. Observations and Findings

b.1 RFC DC-12-2436 - installed around November 1985 for Unit 1 and July 1991 for Unit 2

This RFC modified the impellers for the turbine driven auxiliary feedpumps (TDAFPs) to improve pump performance. The total developed head (TDH) at design flow was increased by about 7.5%, and the shutoff head increased by a factor of two (2). The safety review memo, dated September 27, 1979, concluded that this RFC did not constitute an unreviewed safety question because the improved pump performance increases plant safety. The inspectors reviewed UFSAR Section 10.5.2, "Auxiliary Feedwater System," and noted that the pump design parameters were listed in Table 10.5-1. These parameters had not been updated to reflect the improved TDAFP performance characteristics, specifically:

	UFSAR Table 10.5-1 Value	Modified Impeller, per RFC DC-12-2436
Design Total Dynamic Head (ft)	2714	2925

Total Shut-Off Head (psig)	1530	1580

In response, the licensee indicated that the UFSAR values were the minimum design requirements that a new pump was expected to meet, and did not necessarily reflect actual safety analysis requirements. The licensee acknowledged that the higher shutoff head could impact other component maximum design pressures. However, the licensee relied on the design control process to ensure that higher system operating pressures would be appropriately analyzed. The inspectors did not identify any components that were affected by the higher operating pressures.

b.2 RFC DC-12-2883 - installed around November 1991

This RFC installed ventilation equipment to provide supplemental cooling to electrical panels containing solid state electronic equipment located in each diesel generator room. The supplemental cooling was continuously provided regardless of diesel generator operating status. This change was characterized as a system enhancement that was intended to extend equipment qualified life and was not required for diesel generator operability. The safety review memos, dated June 17, 1986, and April 10, 1989, concluded that this RFC was not a change to the plant as described in the UFSAR, the Emergency Plan, or the Security Plan, and did not constitute an unreviewed safety question. The inspectors reviewed pertinent sections of the UFSAR, for example, Sections 1.2, 7.5, 8.4, 9.9, and 9.10, and determined that the diesel generator room ventilation system was not described in the UFSAR.

b.3 Plant Processes that Bypass the Design Control Process

The inspectors were concerned that other avenues existed in plant processes that could change the plant bypassing the design control process without recognizing that the plant was being changed. Examples include engineering memos, modification package addendums, action requests (ARs), and job orders (JOs).

The licensee initiated CR 98-0206 to document several findings from their self-assessment effort regarding potential pathways that could bypass the design change process. Approximately 17 avenues were identified. Seven avenues no longer exist and five avenues were still under review as to whether a change in the process was necessary. Five processes will require changes in order to prevent recurrence. The licensee's review sample was selected from a population size beginning in the 1980s. By the end of the inspection, a number of the process avenues indicated that a change to the plant had been made bypassing the design process and without performing a safety screening. The licensee performed a safety screening for the identified changes but did not identity any changes that required a safety evaluation. The licensee indicated that the reviews would be completed prior to Mode 4 and that any procedure/process changes would be completed prior to Mode 2.

b.4 Old Design Control Process

In the past, the design process was implemented through various AEP and Cook Plant procedures. With many avenues to change the plant, this may have contributed at times, to not recognizing that the plant as described in the UFSAR was being changed. The licensee recognized that the design change process needed improvement and has taken steps to combine the request-for-change (RFC), minor modification (MM), and plant

modification (PM) processes. Permanent modifications will be implemented as a design change package (DCP). Modifications that were approved for installation using the old processes were re-evaluated following recent 50.59 training. The inspectors reviewed the safety evaluations for these modifications and determined that they did not create an unreviewed safety question (USQ).

c. Conclusions

Even though early safety review memos lacked sufficient detail to make an independent assessment, the inspectors concluded that the Safety Review Checklist (unreviewed safety question determination) performed for the above modifications appeared to arrive at the correct conclusions, in that, the modifications did not change the plant as described in the UFSAR or did not constitute an unreviewed safety question. Recent modification safety evaluations have significantly improved. In addition, the inspectors concluded that the licensee was adequately addressing other plant processes that could bypass the design control process.

S2.4 10 CFR 50.59 Screenings and Safety Evaluations

a. Inspection Scope

The inspectors independently reviewed safety evaluations that were reviewed by the licensee as stated in AEP letter No. AEP:NRC:1260G5, dated December 31, 1997, "Response to the Request for Additional Information Related to the 10 CFR 50.59 Program Questions Raised During the December 22, 1997, Public Meeting." These documents were reviewed to ensure that no operability issues or USQs were created. In addition, the inspectors reviewed these documents to ensure that no changes were implemented prior to completing a safety evaluation. The documents reviewed included the following:

- 35 procedural 10 CFR 50.59 screenings, including procedure change sheets and revisions,
- 11 procedural 10 CFR 50.59 safety evaluations, and
- 25 design change 10 CFR 50.59 safety evaluations and their associated screenings.
- Procedure No. PMP 1040.SES.001, "Safety Evaluation Screening"

b. Observations and Findings

b.1 A potential unanalyzed condition resulting from an improper 10 CFR 50.59 Safety Evaluation for Procedure Nos. 01(02)-OHP 4023 ES-0.1, Revision 13(12), "Reactor Trip Response"

A safety evaluation was performed on May 5, 1997, to support changes to the reactor trip response procedure. The procedure change would allow the reactor operator to have one rod fully withdrawn and all other rods "indicating" 12 steps out without borating. The current procedure revision required boration if any rod was not "fully inserted." However, this procedure change was made without the licensee fully understanding that TS 3.1.1.1 shutdown margin (1.3% delta k/k) could be exceeded. The inspectors determined that this change constituted a potential unanalyzed condition because no analyses had been

performed to determine if the shutdown margin would be exceeded, or to bound all possible rod positions when accounting for the ± 12 step control rod position accuracy. This change could be a potential USQ since the boron dilution and secondary pipe rupture scenarios were UFSAR Chapter 14 analyzed accidents. Although the licensee's safety evaluation discussed the potential impact on Chapter 14 accidents, no consideration was given to the possibility that the shutdown margin may not be met. Therefore, the inspectors considered the licensee's safety evaluation inadequate, in that, it lacked an evaluation of the potential affects of this change on the shutdown margin. The failure to consider the affects of this procedure change on the shutdown margin during the safety evaluation review is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-10; EEI 50-316/98004-10).

In response, the licensee reperformed the safety evaluation. In addition, the licensee analyzed the shutdown margin with all rods at 24 steps and the highest worth rod stuck full out. The analyses concluded that although the margin to the TS limit was reduced, the TS shutdown margin would not be exceeded.

The inspectors were concerned that 50.59 process deficiencies were still occurring since this safety evaluation had been recently reviewed by the licensee as part of their short term assessment effort and was found to be acceptable (Report No. 97-06).

b.2 <u>A procedure design change, 12-THP 6010 RPP.415, Revision 5, CS-1, "Replacement of Contaminated Filters," was implemented prior to completion of an appropriate 10 CFR 50.59 Safety Evaluation</u>

The inspectors identified that a design change had been procedure implemented and turned over to operations in July 1996. A safety evaluation was not completed until April 1997 for a filter media micron size and composition change. However, the system engineer discovered the problem during a system walkdown prior to valving the filter into the process stream. Although no operability issues resulted, this was an example where the 50.59 process controls failed. This was one of the safety evaluations recently reviewed by the licensee as part of their short term assessment (Report No. 97-06). The following chronology of events took place:

December 29, 1989	A 50.59 screening was performed for minor modification No.12 MM 078 to change the type of filters used in the RCS, seal water injection, and seal water return filters to allow use of more than one micron size filter media. The screening evaluated filter media size ratings between 0.25 to 0.45 microns and answered "NO" to all of the screening questions. The licensee did not recognize that the change in filter media size was an implied change to the plant.
June 5, 1995	A safety analysis was requested for reducing the chemical volume control system (CVCS) filter micron size to 0.1 microns. In correspondence with individuals who were no longer with AEP, it was decided that the 0.1 micron size filters were acceptable and orders were sent to procure the new filters. It was decided that no 50.59 safety evaluation was required.
August 9, 1995	An equivalency review was requested to determine if the filter change was a like-for-like replacement. Depending on the results, a design change may or may not be needed.

October 11, 1995	A 50.59 screening was performed to use 0.1 micron filters. The screening answered “NO” to all of the screening questions. Again, the licensee did not recognize that this was an implied change to the plant.
June 1996	The 0.1 micron filters were installed in CVCS and turned over to operations
October 18, 1996	During a walkdown, the system engineer tried to determine if the CVCS filters had been properly reviewed. The system engineer initiated a condition report when review documentation could not be located. Operations decided not to valve in the filters until the issue was resolved.
October 18, 1996	The licensee performed a Prompt Operability Determination and concluded that no operability concerns existed.
February 2, 1997	A new 50.59 screening was performed for the 0.1 micron filter replacements. Two (2) screening question ”YES” answers were obtained.
April 18, 1997	A full safety evaluation was performed for the 0.1 micron filter replacements. The evaluation determined that an unreviewed safety question did not exist.

Failure to perform an adequate safety evaluation prior to the CVCS filter change is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-11; EEI 50-316/98004-11).

b.3. Design change No. RFC-DC-12-2665 safety evaluation

The inspectors reviewed the safety evaluation, dated November 14, 1983, performed for the installation of CVCS cross-tie valves and a 4 inch cross-tie line between the units. This safety evaluation was reviewed during the short term assessment and was considered inadequate by the licensee. Condition Report No. 97-3266 was initiated to evaluate the unit cross-tie valves and the potential for an event on one unit to adversely impact the unaffected unit.

The licensee determined that documentation evaluating the impact on the unaffected unit for Appendix R and other emergency response scenarios when the cross-tie valves were opened did not exist. A Mode 4 restraint was put in place. The restraint was removed on December 14, 1997, after procedure Nos. 01(02)-OHP 4023.016.004, “Loss of Component Cooling Water,” and 01(02)-OHP 4025.LS-6, “RCS Make-Up, Seal Injection, and boration With the CVCS Cross-Tie,” had been revised with tie-line flow limits.

However, the inspectors identified the following additional concerns:

- No guidance existed in the revised procedures to alert operators on the unaffected unit that ECCS operability could be affected when the cross-tie valves were opened.

- No testing or calculations had been performed to verify that adequate flow through these valves could be achieved for the affected unit without adversely impacting the unaffected unit.

- Additional procedures required revising.

  01(02)-OHP 4023.FR-C.1, “Response To Inadequate Core Cooling”

  01(02)-OHP 4023.FR-C.2, “Response to degraded Core Cooling”

  01(02)-OHP 4023.ECA-1.1, “Loss of Emergency Coolant Recirculation”

The licensee revised all affected procedures to recognize entry into TS 3.0.3 when the cross-tie valves were opened, and performed a calculation that demonstrated adequate CVCS cross-tie line flow capability. However, the safety evaluation review for this procedure change was inadequate in that it did not evaluate the CVCS cross-tie line flow effects on the unaffected operating unit and it lacked an evaluation of the affect of the six additional procedures. Failure to perform an adequate safety evaluation for the procedure changes is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-12; EEI 50-316/98004-12).

b.4 <u>10 CFR 50.59 evaluation lacked adequate justification regarding RCP seal injection throttle valves reach rods</u>

On October 28, 1996, the licensee initiated CR 96-1727 documenting that the Unit 2 RCP seal injection throttle valves were disconnected from their reach rods and plant operation with these reach rods disconnected may not meet the plant’s design basis. A subsequent investigation revealed that the valves had been replaced in the 1980s and due to differences in the new valve design, the reach rods could not be re-connected. The licensee could not provide a safety evaluation justifying the as-found condition. Subsequently, job orders were issued to re-connect the reach rods. An operability determination performed on October 29, 1996, justified valve operability since the valves had no safety function and could be easily repositioned using the valve handwheel.

On October 16, 1997, CR 97-2879 was initiated during a corrective action audit. The audit questioned the conclusions drawn in the original operability determination since the valves were described in UFSAR Section 9.2. The licensee initiated another safety evaluation to justify leaving the reach rods disconnected. This was based on infrequent valve operation, easy valve manipulation using a ladder, and the change not impacting UFSAR assumptions or plant procedures.

However, the inspectors determined that the safety evaluation was inadequate, in that, it failed to evaluate four (4) EOP and Abnormal Operating Procedures that contained steps requiring these valves to be repositioned. For example, procedure No. 01-OHP 4022.064.002, “Loss of Control Air Recovery,” dated January 6, 1998, required valve manipulations during a loss of control air scenario. In addition, the inspectors were concerned that these valves may not be easily repositioned because they required a ladder to reach their handwheel. Ladders were not found on this level of the auxiliary building. The nearest location was a ladder located on the next level. In addition, an inspector walkdown identified tags on the Unit 1 valves stating that the valves were “extremely difficult to operate.”

The failure to perform an adequate safety evaluation for changes to the plant affecting four EOP and Abnormal Operating Procedures is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-13; EEI 50-316/98004-13).

b.5 Safety Evaluation No. SECL-97-198, dated November 12, 1997, "FSAR Change to Support Increased CCW Temperature"

This safety evaluation was performed to support a CCW temperature increase from 95°F to 120°F for a single train CCW cooldown of the plant. The letdown heat exchanger could be affected by the increased CCW temperatures. UFSAR Table 9.5-2 letdown heat exchanger CCW flow design value was 984 gpm at standard conditions. However, the safety evaluation was inadequate, in that, it did not identify that the letdown heat exchanger process control system could automatically open the CCW outlet flow control valve wide open in an attempt to maintain the outlet temperature at 120°F. This would cause the branch flow to go to a preliminary analysis value of 1400 gpm. The safety evaluation did not identify the potential for exceeding the UFSAR letdown heat exchanger design value.

Failure to perform an adequate safety evaluation to support changes to CCW flows that could exceed the UFSAR CCW heat exchanger design flow values is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-14; EEI 50-316/98004-14).

The licensee subsequently performed a 50.59 safety evaluation that adequately evaluated the increased flow rate. In fact, the flow could approach 1900 gpm without excessive heat exchanger vibration.

c. Conclusions

Even though no unreviewed safety questions were identified, the inspectors were concerned that safety evaluations continue to have deficiencies. Seven (7) safety evaluations (including Section C2.2.b.3.4 and S5.2) were identified to be inadequate. Two (2) of these examples were previously reviewed by AEP staff during the short term assessment reviews and were found to be acceptable. The inspectors concluded that weaknesses still exist in the safety evaluation program. The licensee has taken steps to better control the safety evaluation process. Initially, there existed several safety review procedures. These procedures were used by AEP and Cook organizations. The safety review procedures have been combined into one procedure for use by all plant organizations.

S5 Staff Training and Qualification

S5.1 Anticipated Transients Without Scram (ATWS) and Station Blackout (SBO) Scenario's were Not Considered as UFSAR Chapter 14 Accidents

a. Inspection Scope

The inspectors reviewed 50.59 screening/safety evaluation training provided to screening and safety evaluation preparers and reviewers.

b. Observations and Findings

b.1 50.59 Training

The inspectors determined that the 10 CFR 50.59 program was not effective in training licensee personnel on what constitutes a design change. Weaknesses were identified in the 10 CFR 50.59 training program and through procedural reviews on recognizing plant changes that were required to be analyzed as part of the plant's licensing basis, such as ATWS and SBO. The Nuclear Safety & Analysis group was responsible for 10 CFR 50.59 training. The inspectors reviewed a February 1997 10 CFR 50.59 proficiency test that the licensee gave to their safety evaluation reviewers. The inspectors determined that the test contained a question that appeared contrary to NRC staff position regarding accidents previously evaluated in the safety analysis report (SAR). NRC staff position was that accidents previously evaluated in the SAR were considered to be those anticipated transients and design basis accidents evaluated in the SAR (Chapter 14 accidents), as well as events described in the SAR which the plant was designed to endure, such as earthquakes, fires, and floods. This would also include events or conditions added to the licensing basis, such as ATWS and SBO scenarios.

The 10 CFR 50.59 test question implied that a proposed change involving the creation of a possible ATWS scenario need not be considered a USQ if the event was not required to be evaluated in the same context as a postulated UFSAR Chapter 14 accident. The licensee used the following guidance to evaluate changes to the facility; "the possible accidents or malfunctions of a different type are limited to those that are as likely to happen as those considered in the SAR." However, the inspectors determined that this guidance was contrary to NRC staff SBO positions regarding ATWS and SBO scenarios.

b.2 Procedure Nos. 01(02)-OHP 4023.ECA-0.2, dated October 27, 1997, Change Sheet (CS)-1, "Loss of All AC Power Recovery With SI Required"

The inspectors reviewed 55 procedure changes involving ATWS and SBO mitigation and recovery scenarios initiated between the years of 1980 through 1997, and several annual functional procedure reviews. As a result, the inspectors identified several examples where the licensee justified no impact on the UFSAR because ATWS and SBO scenarios were beyond Cook's design basis and recovery from such an accident was not accounted for by the UFSAR. For example, the 10 CFR 50.59 screenings, dated January 3, 1998, that were applicable to procedure Nos. 01(02)-OHP 4023.ECA-0.2, determined that no changes to the plant as described by the UFSAR occurred because SBO was a scenario beyond the design basis and was not accounted for by the UFSAR. In addition, a periodic licensee review of procedure No. 01-OHP 4023.ECA-0.0, "Loss of All AC Power," stated that FSAR/UFSAR references were not

reviewed because loss of all AC power was not an analyzed accident. This further demonstrates that the licensee was not fully evaluating changes to procedures involving ATWS and SBO scenarios.

In response, the licensee sent an electronic memo to qualified safety evaluators stating that ATWS and SBO scenarios were part of the licensing basis and that these scenarios need to be considered along with other UFSAR Chapter 14 accident scenarios. In addition, safety reviewer requalification training, beginning in March 1998, was to include ATWS and SBO scenarios. Subsequent to the inspection, the licensee provided training materials to the inspector that included ATWS and SBO scenarios. The training materials adequately addressed that ATWS and SBO scenarios were to be considered along with UFSAR Chapter 14 scenarios during unreviewed safety question reviews.

c. Conclusions

The inspectors concluded that the screenings performed for the ATWS and SBO procedure changes did not require full safety evaluations. However, the inspectors were concerned that licensee 50.59 reviewer qualification training did not treat ATWS and SBO scenarios as accidents requiring the same level of review as UFSAR Chapter 14 accident scenarios.

S5.2 Lack of Understanding of What Constitutes a Change to the Plant

a. Inspection Scope

The inspectors reviewed several 50.59 screenings to determine if screening preparers understood what constitutes a design change.

b. Observations and Findings

The inspectors reviewed the 10 CFR 50.59 screening, dated January 3, 1998, that was performed for procedure Nos. 01(02)-OHP 4023.ECA-0.2, “Loss of All AC Power Recovery With SI Required.” This screening evaluated the change in RWST low level setpoint from 32 to 20%. The RWST low level setpoint was discussed in UFSAR Section 6.2, “Emergency Core Cooling Systems.” The low level setpoint was the point where the operator initiated transfer to recirculation. However, the 10 CFR 50.59 screening was circled “NO” in response to Safety Evaluation Screening Checklist question No. 2.1, “A change to plant as described in the FSAR, Emergency Plan or Security Plan?.” Procedure No. PMP 1040.SES.001, “Safety Evaluation Screening,” requires, in part, that changes to structures, systems and components which are not explicitly described in the FSAR may also require safety evaluations if they have the potential for altering the design function or method of performing the function of structures, systems and components which are described in the FSAR. The low level RWST alarm was described in UFSAR Section 6.2, “Emergency Core Cooling Systems,” however, the alarm value was not explicitly stated. The inspectors were concerned that the licensee should have recognized that this was a change to the plant as described in the UFSAR and should have acknowledge this change in the screening evaluation with a “YES” answer. A safety evaluation was attached to the screening, however, this safety evaluation had been performed for procedural changes made to procedure ES-1.3. In addition, this same approach had been taken with 50.59 screenings related to several other emergency response procedures incorporating the RWST low level setpoint change.

The licensee did not identify that the RWST low level alarm setpoint change was a change

to the plant as described in the UFSAR and therefore, the 50.59 screening completed had not adequately evaluated this change from an administrative standpoint. Failure to perform an adequate safety evaluation for the RWST low level alarm setpoint change is considered an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-315/98004-015; EEI 50-316/98004-015).

The inspectors did not have a safety concern, since the safety evaluation performed for procedure ES-1.3 adequately addressed the 32 to 20% level change from a technical standpoint.

c. Conclusions

The inspectors concluded that weaknesses still exist in the 50.59 program. In this case, the licensee did not recognize an implied RWST low level alarm setpoint change was a change to the plant. As a result, procedure specific safety evaluations were not performed.

S7 Quality Assurance in Engineering Activities

S7.1 Quality Assurance Organization Activities

a. Inspection Scope

The inspectors reviewed past licensee quality assurance (QA) organization audits and surveillances to determine whether or not issues identified by the AE team had been previously identified by the QA organization.

b. Observations and Findings

The inspectors reviewed several licensee audits conducted prior to the AE inspection. The licensee had identified problems with the safety evaluation and calculation control programs. Following discussions with QA management, the inspectors identified the following factors that contributed to the QA organization's failure to identify issues similar to the AE team:

- QA Activities Did Not Verify or Question Assumptions in Calculations

  The inspectors determined that although QA reviewed calculations, the audits usually did not verify that calculation assumptions were appropriate. This was considered a weakness, particularly since the AE team identified unverified assumptions and design inputs.

- Containment Recirculation Sump Not Viewed as a "System"

  The inspectors determined that prior to the AE inspection, the containment recirculation sump had not been considered a "system" but only a part of the containment structure. As a result, audits were not performed on the containment sump from a "system" point of view.

- Although the QA Organization Identified Problems Similar to the AE Team, Problems Were Not Recognized and Addressed Programmatically

  The inspectors determined that although QA audits conducted prior to the AE

inspection identified problems such as 50.59 screening and 50.59 safety evaluation weaknesses, and calculation deficiencies; the QA organization did not fully understand the scope of the problem. As a result, programmatic problems in the 50.59 screening and 50.59 safety evaluation program were not identified.

c. Conclusions

The inspectors concluded that due to QA organization audit methodology weaknesses, such as limited scope 50.59 screening, safety evaluation and calculation reviews, as well as weaknesses regarding the follow up of identified problems, the licensee's QA organization did not identify the extent of the problems identified by the AE team. This is considered an open item (50-315/98004-18; 50-316/98004-18) pending NRC review of the QA audit methodology.

S7.2 Corrective Actions

a. Inspection Scope

The inspectors followed up on previous NRC inspection finding Nos. 50-315/97004-04 and 50-316/97004-04 which involved the placement of leak collection devices without recognizing that the installation may impact the affected system's design basis.

b. Observations and Findings

On March 6, 1997, the licensee identified that a plexiglass leak collection device (LCD) had been installed below the Unit 2 control room emergency ventilation system (CREVS) return air duct. No evaluations had been performed to determine if the CREVS design basis would be affected if the LCD had been sucked up against the return air duct during CREVS emergency actuation. This issue resulted in a 10 CFR 50.59 violation for failing to recognize a change to the facility that could have affected CREVS operability. The licensee revised procedure No. PMP 5040 MOD.001, "Temporary Modifications," to treat leak collection devices as a temporary modification (TM). This should ensure that future LCDs installations were reviewed for system operability impact and that a 10 CFR 50.59 screening was performed. In addition, the licensee issued procedure No. PMP 5020.LCD.001, "Control of Leak Collection Devices," Revision 0, dated October 27, 1997. This procedure required that LCDs not be installed in a configuration that could constitute a

design change.

On December 24, 1997, the licensee identified that LCDs had been installed under each RWST 10 inch overflow pipe to collect condensed water droplets. The LCDs were located approximately ¼ inch below the overflow pipes. This installation had the potential to impact the RWST level instrumentation during rapid RWST draw-down if the LCDs were sucked up against the overflow pipes. Licensee staff directed that the collection devices be removed. However, the resident inspector noticed that the collection devices had not been removed. Apparently, due to a communication error, American Nuclear Resources (ANR) personnel merely straightened out the collection devices. Therefore, the corrective actions initiated for this issue in response to the first occurrence on March 6, 1997 failed to prevent recurrence. Failure to implement corrective actions for a previous condition adverse to quality to prevent recurrence is considered an apparent violation of 10 CFR 50, Appendix B, Criterion XVI
(EEI 50-315/98004-16; EEI 50-316/98004-16).

c. Conclusions

The initial corrective actions appeared reasonable. However, the inspectors were concerned that plant personnel, such as ANR, may not fully understand the TM and LCD procedure requirements. As such, they did not realize that the RWST installed collection devices constituted a design change and should have been removed.

S3 Short Term Assessment Conclusion

The inspectors concluded, in general, that corrective actions to address the short term assessment items were appropriate and bound the AE inspection identified concerns. Calculations reviewed contained some discrepancies, however, none of the discrepancies affected system/component operability. This was similar to the licensee's results from their self assessment. In addition, the modifications reviewed followed acceptable design control practices.

The inspectors were concerned that weaknesses still exist in the safety evaluation process, particularly in recognizing when work in the plant constitutes a design change. The licensee has taken steps to simplify the safety review process to help identify when changes were taking place. In addition, the licensee has undertaken a review of other avenues that could bypass the design control process. The review samples were selected from the early 1980s through the present. A number of process avenues were identified to have implemented plant changes, however, none required a full safety evaluation to be performed. The additional 50.59 screening review results indicate that past changes to the plant did not create an unreviewed safety question.

V. Management Meetings

X. Exit Meeting Summary

On January 27, 1998, the inspectors presented the inspection results to licensee management. The licensee acknowledged the findings presented. In addition, a CAL update was provided during the public meeting held at D. C. Cook on February 27, 1998.

The inspector asked the licensee whether any material examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

*^M. Ackerman, Nuclear Licensing
*^K. Baker, Production Engineering
*^P. Barrett, Performance Assurance
*^A. Blind, Nuclear Engineering Vice President
*^S. Brewer, Regulatory Affairs
*^D. Cooper, Plant Manager
*^M. Depuydt, Nuclear Licensing
*^M. Finissi, Plant Engineering
*^E. Fitzpatrick, Executive Vice President
*^D. Hafer, Plant Engineering
*^J. Kingseed, Nuclear Safety and Analysis
*^J. Kobyra, Steam Generator Project
*^S. Lies, System Engineering
*^T. Postlewait, Design Engineering
*^J. Sampson, Site Vice President
*^J. Wiebe, Performance Engineering

NRC

^A. Beach, Regional Administrator, RIII
*^B. Bartlett, Senior Resident Inspector, RIII
*^B. Burgess, Chief, Projects Branch 6
*^B. Fuller, Resident Inspector, RIII
*^R. Gardner, Chief, Engineering Specialists Branch 2, RIII
^J. Gavula, Chief, Engineering Specialists Branch 1, RIII
^M. Holmberg, Reactor Engineer, RIII
^R. Savio, Acting Director, Project Directorate III-3, NRR
^E. Schweibinz, Project Engineer, RIII
^J. Strasma, Public Affairs Officer, RIII

* Denotes those in attendance on January 27, 1998

^ Denotes those in attendance on February 27,1998

INSPECTION PROCEDURES USED

IP 40500	Effective of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 93801	Safety System Functional Inspection

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-315/98004-01 50-316/98004-01	EEI	Failure to perform a safety evaluation screening
50-315/98004-02	EEI	Failure to perform a safety evaluation screening
50-315/98004-04 50-316/98004-04	EEI	Failure to perform a safety evaluation screening
50-315/98004-05 50-316/98004-05	EEI	Inadequate safety evaluation review
50-315/98004-09 50-316/98004-09	EEI	Inadequate design control
50-315/98004-10 50-316/98004-10	EEI	Inadequate safety evaluation review
50-315/98004-11 50-316/98004-11	EEI	Inadequate safety evaluation review
50-315/98004-12 50-316/98004-12	EEI	Inadequate safety evaluation review
50-315/98004-13 50-316/98004-13	EEI	Inadequate safety evaluation review
50-315/98004-14 50-316/98004-14	EEI	Inadequate safety evaluation review
50-315/98004-15 50-316/98004-15	EEI	Inadequate safety evaluation review
50-315/98004-16 50-316/98004-16	EEI	Inadequate corrective action

ITEMS OPENED, CLOSED, AND DISCUSSED

50-315/98004-07 50-316/98004-07	URI	Operability determination for procedure No. ES-1.3
50-315/98004-03 50-316/98004-03	IFI	Verification of sump screen as-left configuration
50-315/98004-06 50-316/98004-06	IFI	Review resolution of calculation discrepancies
50-315/98004-08 50-316/98004-08	IFI	Verify W provided approved calculation
50-315/98004-17 50-316/98004-17	IFI	Review AEP to W interface
50-315/98004-18 50-316/98004-18	IFI	Review QA audit methodology

LIST OF ACRONYMS USED

AE	Architectural and Engineering
AEP	American Electric Power
AEO	Auxiliary Equipment Operator
AFW	Auxiliary Feedwater
ANR	American Nuclear Resources
AR	Action Request
ARE	Alarm Response Procedure
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BAT	Boric Acid Transfer
BIT	Boron Injection Tank
CAL	Confirmatory Action Letter
CCP	Centrifugal Charging Pump
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CREVS	Control Room Emergency Ventilation System
CR	Condition Report
CTS	Containment Spray System
CVCS	Chemical Volume and Control System
DB	Design Basis
DBA	Design Basis Accident
DBD	Design Basis Document
DCN	Design Change Notice
DCP	Design Change Package
d/p	Differential Pressure
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
ECP	Engineering Control Procedure
EDG	Emergency Diesel Generator
EEI	Escalated Enforcement Item
ELO	Emergency Leakoff
EOP	Emergency Operating Procedure
ERG	Emergency Response Guidelines
ESF	Engineered Safety Feature
ESW	Essential Service Water
FME	Foreign Material Exclusion
FSAR	Final Safety Analysis Report
°F	Degree Fahrenheit
gpm	gallons per minute
IFI	Inspection Followup Item
ISI	Inservice Inspection
IST	Inservice Testing
JO	Job Order
JOA	Job Order Activity
KV	Kilovolt

LIST OF ACRONYMS USED (cont'd)

LCO	Limiting Condition for Operation
LCD	Leak Collection Device
LER	Licensee Event Report
LOCA	Loss-Of-Coolant-Accident
MM	Minor Modification
MWt	Mega-Watt thermal
NPSH	Net Positive Suction Head
PMI	Plant Manager Instruction
PMP	Plant Manager Procedure
psig	Pounds Per Square Inch Gauge
QA	Quality Assurance
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RFC	Request For Change
RHR	Residual Heat Removal
RO	Reactor Operator
RWST	Refueling Water Storage Tank
SAR	Safety Analysis Report
SBO	Station Blackout
SFP	Spent Fuel Pool
SI	Safety Injection
SOPI	System Operational Performance Inspection
SRO	Senior Reactor Operator
SS	Shift Supervisor
TDAFP	Turbine Driven Auxiliary Feedwater Pump
TDH	Total Developed Head
TM	Temporary Modification
TS	Technical Specification
TSC	Technical Specification Clarification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
US	Unit Supervisor
USQ	Unreviewed Safety Question
V	Volt
VCT	Volume Control Tank
VIO	Violation
W	Westinghouse

List of Documents Reviewed

Calculation No. TH-97-12, Rev. 0, Containment Sump Level Following a Large Break LOCA, approved October 22, 1997

Calculation No. TH-97-13 (FAI/97-104), Rev. 0, Small Break LOCA Analyses for the D. C. Cook Units 1 and 2, approved October 6, 1997

Calculation No. TH-97-18, Rev. 0, Minimum Active Sump Water Level at the Initiation of Transfer to Recirculation, approved December 12, 1997

Calculation No. TH-97-19, Rev. 0, Effect of Additional Isolated Water Volumes on Sump Fill Calculations, approved January 7, 1998

Calculation No. TH-98-01, Rev. 0, Active Sump Inventory at Time of Peak Containment Pressure, approved January 16, 1998

Procedure Nos. 01(02)-OHP 4023.ES-1.3, Transfer to Cold Leg Recirculation, Revision 5, with an effective date of January 3, 1998

Procedure No. 01-OHP 4023.ES-1.3, Transfer to Cold Leg Recirculation, Revision 4, with an effective date of January 6, 1997

Change Sheet No. 1 to Procedure No. 01-OHP 4023.ES-1.3, Transfer to Cold Leg Recirculation, Revision 4, August 22, 1997

Change Sheet No. 2 to Procedure No. 02-OHP 4023.ES-1.3, Transfer to Cold Leg Recirculation, Revision 4, August 22, 1997

Procedure No. 01-OHP 4023.ECA-1.1, Loss of Emergency Coolant Recirculation, Revision 4, with an effective date of January 12, 1996

UFSAR Section 14.3.1, Large Break LOCA Analysis

UFSAR Section 14.3.4, Containment Integrity Analysis

Technical Specification Section 3.6.2.2, Spray Additive System

FSAR Appendix N, Ice Condenser Containment System Performance Evaluation Report, Question 23, dated July 1973 (Amendment 45)

Letter No. AEP:NRC:0900K, E. E. Fitzpatrick to U. S. Nuclear Regulatory Commission, Request for Exigent Technical Specification Amendment, Technical Specification 3/4.6.5, Ice Weight and Surveillance Requirement, and Technical Specification 3/4.5.5 Basis for Refueling Water Storage Tank Change, October 8, 1997,

Attachment A (cont'd)

Letter, John B. Hickman (USNRC) to E. E. Fitzpatrick, Donald C. Cook Nuclear Plant, Units 1 and 2 - Issuance of Amendments Re: Ice Weight and Surveillance Requirements (TAC Nos. M99742 and M99743), January 2, 1998

Westinghouse letter No. AEP-97-172, J. Waleko to J. Kingseed (AEP), Donald C. Cook Nuclear Plant Units 1 and 2, SECL-97-217, “Revision 5 of 02-OHP 4023.ES-1.3, Transfer to Cold Leg Recirculation/ECCS Post-Accident Operability”, October 22, 1997

Westinghouse letter No. AEP-98-001, Rev. 1, Donald C. Cook Nuclear Plant Units 1 and 2, Containment Integrity Analysis, January 02, 1998

Memo, R. Sartor to ENSA Calculation Nos. TH-97-12 File and TH-97-13 File, Effect of Revised Containment Volumes Listed in DC-D-3200S-227, Rev. 3 on Post-LOCA Sump Water Levels Calculated by ENSA Calculation TH-97-12, Rev. 0 and Fauske & Associates, Inc. Report FAI/97-104, October 24, 1997

Memo, Jim Feinstein to Paul Cooper, Cook Nuclear Plant Units 1, 2, Safety Review of Revision 5 to Procedure Nos. 01(02)-OHP 4023.ES-1.3, Transfer to Cold Leg Recirculation and Related UFSAR Changes - Revision 1, October 29, 1997

Memo, Jim Feinstein to Paul Cooper, Cook Nuclear Plant Units 1, 2, Modification 3 to Safety Review of Revision 5 to Procedure Nos. 01(02)-OHP 4023.ES-1.3, Transfer to Cold Leg Recirculation and Related UFSAR Changes, December 22, 1997

Memo, R. Sartor to J. G. Feinstein, Minimum Active Sump Water Level at the Initiation of Transfer to Recirculation - Confirmation of Analysis Assumption, January 16, 1998

NUREG-0737, Clarification of TMI Action Plan Requirements, November 1980, Item II.B.2, Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Postaccident Operations