ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Washington Nuclear Project-2
NRC Inspection Report 50-397/97-13

During the period of July 15 through August 2, 1997, two NRC inspectors conducted an inspection to followup issues previously identified in other inspection reports.

Operations

- While corrective actions to resolve the material buildup problem in Valves FDR V-3 and FDR V-4 were effective, corrective actions to resolve a required reading problem were not. Violation 50-397/9611-04 will be closed, however, an example of a new violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for the failure to correct the required reading issue (Section O8.1).

- The new nuclear safety assurance division procedure properly addressed the technical specification procedural requirements. In addition, licensee conducted surveillances were effective in assuring that other canceled procedure activities were properly conducted. However, there was a failure to update the Final Safety Analysis Report fire protection sections (Section O8.2).

- The root-cause analysis procedure was found to be properly applied. Efforts were in progress to improve the root-cause analysis program (Section O8.3).

- The corrective actions to resolve continuing failures of the motor-to-pump coupling on the ac standby lubricating oil pump were not fully implemented. This was considered to be an example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI (Section O8.4.1).

- Corrective actions to correct and prevent recurring personnel error induced valve and switch mispositioning errors were in progress (Section O8.4.2).

- Actions were in progress to correct recurring personnel errors involving a lack of equipment clearance/procedure adherence and the issuance of inadequate clearance orders (Section O8.4.3).

- Corrective actions to address the reversed termination of electrical equipment and wiring errors were appropriate to the cause (Section O8.4.4).

- Actions to address the occurrence of shorting electrical terminals during the performance of maintenance or surveillance activities were adequate and effective toward preventing a recurrence of the events (Section O8.4.5).

- The corrective actions that addressed the inadvertent initiation of drywell to suppression chamber bypass flow were appropriate for the circumstances and adequate to prevent a recurrence of the events (Section O8.4.6).

- There was a failure to issue a problem evaluation request that would have promptly identified and provided corrective actions for the inadvertent start of a reactor recirculation pump. This item was considered to be an example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI (Section 08.4.7).

- Corrective actions to control a lack of documentation of issues in problem evaluation requests and to resolve the inadequate labeling of radioactive materials were in progress (Section O8.4.7).

Engineering

- The reactor core isolation cooling system was downgraded from safety related to nonsafety related. While the system was found to be operable, it was also found to be nonconforming. The reclassification plan and schedule for returning the reactor core isolation cooling system to safety related were thorough. As the result of these downgrade activities, six reactor core isolation cooling valves were not being tested. The failure to test these valves was considered to be an apparent violation of 10 CFR 50.55a(f). The failure to obtain NRC approval prior to downgrading the system from safety related to nonsafety related was considered to be an apparent violation of 10 CFR 50.59 because it apparently involved an unreviewed safety question (Section E8.2).

- An adequate evaluation of the March 3, 1996, residual heat removal system test results was performed that demonstrated that the results were within the design basis (Section E8.4).

- Multiple examples of Final Safety Analysis Report inaccuracies were identified. While no safety issues or operability issues were identified, these multiple examples were indicative of a failure to update the Final Safety Analysis Report. However, the ongoing implementation of a Final Safety Analysis Report update program permitted the exercising of enforcement discretion in accordance with the revised enforcement policy (Section E8.5).

- Appropriate actions to correct a new and previously unanalyized condition involving the potential overpressurizing of the main steam safety relief valve actuators were being taken. These actions indicated that the actuators were capable of withstanding the additional pressure and that design documentation would be changed to reflect the new design pressure ratings (Section E8.8).

- The current design for the manual initiation of the automatic depressurization system was consistent with Regulatory Guide 1.62 as amended by the requirements of Three Mile Island Action Item II.K.3.18 and no wiring error existed. Functional Control Diagram 731E788 was not consistent with the as-built plant configuration (Section E8.10).

- The lack of inclusion of the high pressure core spray service water loop in the corrosion program was appropriate considering the type of failure that occurred. In addition, the inclusion of the high pressure core spray service water system in the wall thickness measurement program was considered to be a proactive approach toward eliminating any future problems (Section E8.12).

- While Engineering Directorate Manual 2.15 was properly implemented, actions were being taken to further control the number of calculation modification records for plant calculations. A self-assessment performed by the licensee did not identify if the outstanding calculation modification records potentially affected the technical content of the calculations. The NRC plans further review of this area during a future inspection (Section E8.16).

Report Details

To accomplish this inspection, the inspectors reviewed NRC Inspection Reports 50-397/96-11, 50-397/96-201, and 50-397/96-202. The inspectors also reviewed the problem evaluation requests identified in these reports and interviewed personnel. In addition, the inspectors reviewed the licensee's response to the violations documented in Letter GO2-96-201, dated October 15, 1996, to NRC Inspection Report 50-397/96-11 and the NRC acknowledgment letter dated November 14, 1996, the licensee's response to the open items documented in Letter GO2-97-120, dated June 16, 1997, to NRC Inspection Report 50-397/96-201, and the licensee's response documented in Letter G02-97-228, dated December 23, 1997, to Task Interface Agreement 96-TIA-005.

I. Operations

O8 Miscellaneous Operations Issues

O8.1 (Closed) Violation 50-397/9611-04: Failure to implement adequate and timely corrective actions.

Background

In NRC Inspection Report 50-397/96-11, the NRC identified a violation with three examples where the licensee did not provide adequate and timely corrective actions.

The first example occurred on January 19, 1996, when the licensee found that Primary Containment Isolation Valve FDR V-4 did not close due to foreign material on the valve seating surfaces. The licensee did not promptly correct the cause of the foreign material and, as a result, from January 19 through July 6, 1996, Valve FDR V-4 had additional closure failures and a redundant isolation valve, FDR V-3, also failed to close. These additional failures were also attributed to foreign material on the valve seating surfaces.

The second example involved a failure to correct a problem wherein the Corporate Nuclear Safety Review Board was not receiving all of the 10 CFR 50.59 safety evaluations for review. As a result it appeared that an additional 10 CFR 50.59 safety evaluation (SE 95-095) was not reviewed by the Corporate Nuclear Safety Review Board. However, in their response to this violation example (Letter GO2-96-201 dated October 15, 1996), the licensee stated that the Corporate Nuclear Safety Review Board did review Safety Evaluation SE 95-095 and that there was a typographical error in the attachment to the Corporate Nuclear Safety Review Board meeting minutes for Meeting 96-05 that made it appear that the safety evaluation was not reviewed.

The third example involved the failure to complete the corrective actions taken to assure that the fire protection water system would not be placed in an improper lineup. The incomplete corrective action involved the requirement that all operators complete required reading regarding the improper lineup of the fire protection water system. Specifically, the licensee found that operators were using the fire protection water system for nonfire protection activities while only a single source of water was available. This lineup configuration was contrary to the requirements of Procedure 1.3.10, which prohibited the fire protection water system to be used for nonfire protection system purposes unless both fire protection system water supplies were available. This violation was originally cited in NRC Inspection Report 50-397/95-18 in 1995 and was reviewed for closure in NRC Inspection Report 50-397/96-11. During Inspection 50-397/96-11 conducted in July 1996, the inspection team found that the required reading was only completed by 50 of the 111 personnel required to do the reading.

Inspector Followup

Foreign Material on Valve Seating Surfaces

The inspectors interviewed the system engineer and reviewed the modification package for the modification installed to enable the licensee to flush the lines in which Valves FDR V-3 and FDR V-4 were located. In addition to a modification package review, the inspectors walked down a portion of the modification that was accessible. The inspectors also verified that the flushing was accomplished during the past refueling outage and that the valves were stroked on a weekly basis to assure operability until the modification was completed.

The licensee concluded that these flushing operations would remove foreign material buildup in these lines and, therefore, prevent introduction of foreign material on the valve seating surfaces. The modification installed spectacle flanges and tees in these lines to establish a flushing path. To prevent recurrence of a foreign material buildup in these valves the licensee also developed preventative maintenance tasks that will inspect and clean these valves every 3 years and clean (de-sludge) the sumps every 2 years. The inspectors determined that these tasks combined with the quarterly valve stroking procedures should assure that the valves remain operable. Furthermore, the inspectors noted that the licensee will consider accelerated pipe flushing if foreign material buildup was noted or if valve stroking indicated a degradation in the stroke time. The licensee concluded that these activities will assure early detection of valve closure problems based on an established history that demonstrated that it took about 5 years for failures to occur due to a foreign material buildup on the valve seating surfaces.

Corporate Safety Review Board Safety Evaluation Reviews

The inspectors reviewed the documentation regarding the typographical error in the attachment to the minutes of Corporate Nuclear Safety Review Board Meeting 96-05. Review of these meeting minutes indicated that SCN 96-062 was reviewed. Since SCN 96-062 encompassed Safety Evaluation 95-95, this meant that this safety evaluation was reviewed in that meeting. Furthermore, the package of safety evaluations distributed to the 50.59 subcommittee for Corporate Nuclear Safety Review Board Meeting 96-05 documented that SE 95-095 was reviewed. Based on this review, the inspectors concurred with the licensee's finding that the SE 95-095 was reviewed by the Corporate Nuclear Safety Review Board and that the information in the attachment provided to the NRC was incorrect due to the typographical error.

Improper Fire Protection Water System Lineup

The licensee modified their system to assure that all operators were reading the required reading book by adding the required reading to the plant tracking log. The intent of this action was to assure that the required reading was accomplished prior to closing out the plant tracking system item. By listing in the plant tracking system log, the item would be tracked to assure that the required reading was completed. However, due to a misinterpretation of the intent of the plant tracking system entry, personnel assumed that when the required reading topic was placed in the required reading book that the plant tracking log item could be closed out. Therefore, the plant tracking item was closed out even though the required reading was not completed.

To determine if this problem was corrected, the inspectors reviewed the required reading book located in the control room. The inspectors determined that five required reading items were still outstanding. The inspectors also checked the plant tracking log to determine if all the outstanding required readings were entered into the log. The inspectors found that only four of the five items were entered into the log. The licensee stated that the one item not logged was due to the loss of the person in charge of the plant tracking log. While it appeared to the inspectors that the licensee had a system to assure that the required readings were completed, the inspectors identified one operator that still had not read the required material until July 22, 1997 (during this inspection). In addition, the inspectors noted that the licensee's process assumed that the opening of an E-Mail message meant that the message had been read even though there was no acknowledgment in the message confirming that the message was read. The inspectors interviewed five operators that had not acknowledged that they had read the E-Mail message and found that four of these five operators remembered completing the required reading.

The inspectors considered the failure to complete the required reading to be an example of a recurrent failure to complete corrective actions. 10 CFR Part 50, Appendix B, Criterion XVI, requires nonconformances to be promptly corrected and action taken to prevent recurrence of the nonconformance. The recurrent failure to complete the required reading for the fire protection water system lineup problem was considered to be the first example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI (50-397/9713-01).

Conclusions

While corrective actions to resolve the material buildup problem in Valves FDR V-3 and FDR V-4 were effective, corrective actions to resolve a required reading problem were ineffective. Violation 50-397/9611-04 will be closed, however, an example of a new violation was opened for the failure to correct the required reading issue. It was found that Evaluation SE 95-095 was reviewed by the Corporate Nuclear Safety Review Board.

08.2 (Closed) Violation 50-397/9611-05: Failure to implement a nuclear safety assurance division procedure.

Background

NUREG-0737, Section I.B.1.2, "Independent Safety Engineering Group," required the licensee to establish an onsite independent safety engineering group to perform independent reviews of plant operations. Technical Specification 6.2.3 was established to address these requirements and the licensee established a nuclear safety assurance division. Furthermore, since Technical Specification 6.8.1.b requires written procedures for the Nuclear Safety Assurance Division, the licensee developed Procedure PM 1.10.8, "Nuclear Safety Assurance Assessments," to describe the responsibilities and functions of this group. However, Procedure PM 1.10.8 was canceled in 1993 because the procedure was a restatement of the requirements located in Nuclear Operating Standards 20, "Quality Assurance Evaluations." The licensee failed to recognize that the deletion of Procedure 1.10.8 was contrary to the requirements of the technical specifications because the information in Nuclear Operating Standards 20 did not have the same review and approval requirements as procedures governed by the technical specifications.

Inspector Followup

The licensee issued new Procedure SWP-ASU-01, "Evaluation of Programs, Processes, and Suppliers," and trained quality services personnel to assure that future procedure revisions consider all procedure requirements. The inspectors reviewed the new procedure and verified that it encompassed the Nuclear Safety Assurance Division activities as required by the technical specifications. In addition, the inspectors reviewed training records and interviewed personnel to verify that all quality services personnel received the training.

During these reviews, the inspectors noted that the licensee also committed to perform a surveillance to assure themselves that there were no other instances where procedures were improperly canceled. During a review of this activity, the inspectors noted that the surveillance was only performed for the years of 1992, 1993, and 1996. When questioned about the sampling selection, the licensee stated that these years were chosen because most procedure cancellations occurred during the 1992, 1993, and 1996 years. Through further reviews, the inspectors found that a second surveillance was performed that included 1995. To verify that no procedures were improperly canceled, the inspectors reviewed the listing of procedures canceled in 1992, 1993, and 1996 and independently sampled 15 canceled procedures for these years. In addition, since the licensee did not check 1994, the inspectors reviewed a listing of procedures canceled in 1994 and independently sampled procedure cancellations for that year. All canceled procedures were found to be acceptable.

Since 1993, the time that this violation occurred, the licensee developed a data base called the "Requirements Tracking System (RTS)." This system provided assurance that all requirements and commitments were properly incorporated into plant procedures. The inspectors reviewed this data base and determined that the new process should prevent recurrence of this violation.

During a review of the canceled procedures, the inspectors noted that canceled Procedure 15.1.13, "Fire Suppression Systems Tamper Switch Operability," was canceled based on the fact that tamper switches were not necessary if the valves were locked open. However, the inspectors also noted that Amendment 45 of the Final Safety Analysis Report (FSAR), Appendix F, "Fire Protection Evaluation," Tables F.2-1 and F.3-1, specified a monthly checking requirement for control valves (F.2-1) and vent and drain valves (F.3-1). In addition, the inspectors noted that Amendment 51 to FSAR Appendix F, Section F.5.2.3.1c, specified that manual, power operated, and automatic valves in the flow paths be checked for the correct position once per quarter. As the result of procedure reviews and interviews, the inspectors determined that the control valves were being checked on a quarterly basis in accordance with Procedure 15.1.18, "Fire Suppression Systems Valve Alignment," and the vent and drain valves on a refueling cycle basis in accordance with Procedure 3.1.1, "Master Startup Checklist," and Procedure 2.8.7, "Fire Protection System." Since the control valves included selected manual, power operated, and automatic valves, the inspectors determined that Amendment 51 was not adequate in that it did not change FSAR Table F.2-1. In addition, since FSAR Table F.3-1 still specified monthly checking of vent and drain valves and the licensee was only checking the valves every refueling outage (18 months), Amendment 51 failed to revise Table F.3-1 to reflect the new checking frequency.

10 CFR 50.71(e) requires the FSAR update to include the latest material developed. The failure to update FSAR Table F.2-1 to be consistent with Procedure 15.1.18 and FSAR Section F.5.2.3.1c and to update FSAR Table F.3-1 to be consistent with Procedures 3.1.1 and 2.8.7 would be considered two examples of a violation of

10 CFR 50.71(e). However, due to a comprehensive program that was underway to update the FSAR, the NRC believes that these FSAR discrepancies likely would have been identified through this program. Therefore, the NRC is exercising discretion in accordance with Section VII.B.3 of the Enforcement Policy.

Conclusions

The new nuclear safety assurance division procedure properly addressed the Technical Specification procedural requirements. In addition, licensee-conducted surveillances were effective in assuring that other canceled procedure activities were properly conducted. However, there was a failure to update the FSAR fire protection sections.

O8.3 (Closed) Unresolved Item 50-397/96202-02: Two examples where significant problem evaluation requests failed either to provide a root-cause analysis or to provide a root-cause analysis of sufficient depth.

Background

In NRC Inspection Report 50-397/96-202, the NRC identified two significant problem evaluation requests that either did not have a root-cause analysis performed or had an inadequate root cause analysis. While the inspectors considered that the problem evaluation requests were properly evaluated, they were concerned that the licensee did not adhere to their root-cause analysis procedure.

The NRC reviewed Significant Problem Evaluation Request (SPER) 296-0519, which documented an adverse trend of four problem evaluation requests written over a 4-week period. The four problem evaluation requests documented errors in operating mode changes and missed technical specification surveillance requirements. The NRC determined that SPER 296-0519 failed to follow Administrative Procedure 1.3.48, "Root Cause Analysis," Revision 6.

The NRC reviewed SPER 296-0285, which documented an adverse trend in valve and switch positioning. The NRC noted that the problem evaluation request did not have a root-cause analysis performed, which the NRC considered to be a second example of a failure to meet the requirements of the root-cause analysis procedure.

Inspector Followup

The inspectors reviewed Administrative Procedure 1.3.48, "Root Cause Analysis," Revision 6, and discussed the procedure with the licensee. The licensee stated that this procedure was intended to only provide guidance for performing a root-cause analysis. Based on this review, the inspectors determined that Procedure 1.3.48 was properly applied as a guidance procedure.

The inspectors discussed the root-cause analysis process with licensee personnel and reviewed a paper that outlined the licensee's plans for root-cause analysis process changes. The licensee stated that a plant-wide initiative was being planned for additional training on root-cause analysis to provide personnel with better skills. Based on inspection findings, especially with respect to recurring events, the licensee acknowledged that their root-cause analysis needed improvements. The licensee stated that their plan included identifying approximately 20 dedicated individuals to conduct root-cause analyses; training this group in state-of-the-art root-cause analysis techniques; and utilizing this group as team leaders for root-cause analysis of significant problem evaluation requests and other situations as required. The licensee expected to complete initial training by October 31, 1997.

Conclusions

Root Cause Analysis Procedure 1.3.48 was found to be properly applied. Efforts were in process to improve the root-cause analysis program.

O8.4 (Closed) Unresolved Item 50-397/96202-01: Failure to prevent the recurrence of significant conditions that were adverse to quality.

O8.4.1 AC Standby Circulating Lubricating Oil Pump Failures

Background

The NRC identified multiple, recurrent failures of the ac standby circulating lubricating oil pump motor-to-pump coupling. This safety-related pump, used to supply heated lube oil to Emergency Diesel Generator DG2 for initial startup, failed on February 18, 1996. The failure occurred in the motor-to-pump coupling. This failure resulted in a manual start failure of Emergency Diesel Generator DG2 on February 20, 1996, during surveillance testing. While the motor-to-pump coupling was a contributor to this event, the starting of the emergency diesel generator for mitigation of accident conditions was unaffected. Review of this failure by the NRC identified that this coupling failed 2 months earlier and that the motor-to-pump couplings also failed three times prior to 1991 and three additional times since 1991 (not counting 1995 and 1996 failures). Following the 1991 failures, the licensee developed corrective actions that involved increased frequency of alignment checks, the installation of flexible hoses, and replacing the coupling with a different design coupling that was better suited to the operating conditions for the pump. The NRC found that these corrective actions, though considered effective to prevent recurrence of the failures, were not properly implemented.

Inspector Followup

The inspectors reviewed Significant Problem Identification Report 296-0119 and interviewed licensee personnel regarding the ac standby circulating lubricating oil pump failures. The inspectors determined that the findings identified in NRC Inspection Report 50-397/96-202 demonstrated that while the root cause and proposed corrective actions were appropriate, the licensee failed to implement the corrective actions resulting in additional failures of the motor-to-pump coupling. Specifically, while the licensee initially performed increased frequency alignment checks over a 3-year period (after 1991), these alignment checks were subsequently stopped. In addition, the flexible hoses, which were intended to reduce induced piping stresses on the pump motor assemblies, were never installed apparently due to budget considerations. Furthermore, while the licensee investigated and identified new couplings that were more robust for the pump operating conditions, the couplings were not purchased and the in-stock couplings continued to be used. The inspectors determined that the licensee's corrective actions were not fully implemented.

The inspectors considered the failure to fully implement the corrective actions for the motor-to-pump coupling to be the cause of repeated coupling failures. 10 CFR Part 50, Appendix B, Criterion XVI, requires nonconformances to be promptly corrected.. The failure to promptly correct the coupling failures was considered to be the second example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI (50-397/9713-01).

Conclusions

The corrective actions to resolve continuing failures of the motor-to-pump coupling on the ac standby lubricating oil pump were not fully implemented. This was considered to be an example of a violation of 10 CFR Part 50, Appendix B.

O8.4.2 Valve and Switch Positioning Errors

Background

The NRC found that valve and switch positioning errors were identified as a significant issue in Problem Evaluation Request 296-0285. This problem evaluation request identified an adverse trend with valve and switch positioning errors that had occurred since 1995. The NRC was concerned that four recent problem evaluation requests and three gold cards indicated that these mispositioning errors were still occurring and that the licensee's actions to correct these errors were ineffective.

Inspector Followup

The inspectors noted that the licensee issued Significant Problem Evaluation Request 296-0285 on April 19, 1996, to identify an adverse trend. This problem evaluation request identified 26 instances of valve and switch mispositioning errors that

occurred in 1995 due to personnel error. To determine the effectiveness of the corrective actions from this problem evaluation request, the inspectors requested a listing from the plant tracking log of all valve and switch mispositioning errors since January 1, 1997. The licensee provided the inspectors a listing of ten problem evaluation requests covering the time period of January 28 through July 18, 1997, and a gold card, dated December 13, 1996, that identified mispositioning errors. The inspectors reviewed these problem evaluation requests and determined that nine of these requests and the gold card represented additional examples of valve and switch mispositioning errors that were caused by personnel error. Furthermore, the inspectors noted that the licensee issued a second significant problem evaluation request (297-0072) on March 20, 1997, which again identified an adverse trend in human performance that involved mispositioning errors. The inspectors determined that the licensee was taking appropriate actions to resolve this personnel error problem.

Conclusions

Corrective actions to correct and prevent recurring personnel error induced valve and switch mispositioning errors were in progress. The continuing personnel errors were being appropriately identified and trended by the licensee for corrective action.

O8.4.3 Clearance Order and Procedure Problems

Background

The NRC found that clearance order and procedure problems were identified in Significant Problem Evaluation Request 296-0308 dated April 29, 1996. This problem evaluation request identified an adverse trend relative to 12 problem evaluation requests associated with clearance orders and procedures. The NRC reviewed a sample of problem evaluation requests to determine the extent of the issue and to determine if it was resolved. As the result of this review, the NRC identified 15 additional problem evaluation requests that appeared to involve clearance order or procedure problems that occurred since Significant Problem Evaluation Request 296-0308 was issued. The clearance order and procedure problems involved inadequate clearance orders and failures to follow clearance orders procedures.

Inspector Followup

Since the issuance of Problem Evaluation Request 296-0308, the inspectors determined that 12 problem evaluation requests identified instances of personnel errors involving a failure to follow clearance orders or plant procedures and a failure to issue adequate clearance orders. Four of these problem evaluation requests were considered to be significant. The inspectors noted that the licensee issued Significant Problem Evaluation Request 297-0116 on March 28, 1997, that identified the continuing trend regarding inadequate clearance orders.

The inspectors noted that seven problem evaluation requests (296-0364, 296-0415, 296-0428, 296-0497, 296-0650, 296-0832, and 297-0072) involved the failure to adhere to clearance orders or plant procedures and five problem evaluation requests (296-0351, 296-0537, 296-0775, 297-0073, 297-0016) involved inadequate clearance orders. The inspectors determined that the licensee identified the problem (i.e., issued Significant Problem Evaluation Request 296-0308), and had corrective actions in progress.

Conclusions

Actions were in progress to correct recurring personnel errors involving a lack of equipment clearance procedure adherence and the issuance of inadequate clearance orders. The recurring personnel errors were being appropriately identified and trended by the licensee for corrective actions.

O8.4.4 Electrical Wiring and Termination Errors

Background

The NRC found that wiring and termination errors were identified in Significant Problem Evaluation Report 296-0693 dated September 23, 1996. This problem evaluation request identified an adverse trend relative to five problem evaluation requests associated with reversed terminations. The NRC reviewed the five problem evaluation requests and determined that it appeared that the licensee's efforts failed to prevent recurrence of these errors. The NRC based their conclusion on the fact that the licensee limited their analysis to work specifics (i.e., only addressed each specific issue and did not address the underlying cause).

Inspector Followup

The inspectors reviewed the problem evaluation requests that documented these wiring and termination errors. The inspectors also reviewed a listing of problem evaluation requests involving wiring errors for the last year. This listing identified 16 problem evaluation requests that involved wiring errors. The inspectors selected 6 problem evaluation requests from this list for further review. As the result of this review, the inspectors identified 2 Nonsignificant Problem Evaluation Requests 297-0157 and 297-0414 involved wiring errors that were due to human error. The remaining wiring error issues involved either drawing errors from original construction or unrelated design errors. Furthermore, the inspectors were informed that during the period of 1989 through June 1, 1996, there were only 11 wiring errors that involved human performance errors. When combined with the 2 personnel errors identified by the inspectors, this meant that there were 13 wiring errors attributed to personnel errors since 1989. As the result of this review, the inspectors concluded that the wiring and termination issues did not represent a degrading personnel error issue in this area. However, it also indicated that wiring errors had existed in the plant. Discussions with licensee personnel indicated that while electricians and instrumentation and control technicians are trained and required to

check for wiring errors during their work activities. The inspectors also noted, however, due to the development of problem evaluation requests that identified wiring errors and the lowered threshold for writing such problem evaluation requests, the licensee was continuing to identify and correct such issues.

Conclusions

Corrective actions to address the reversed termination of electrical equipment and wiring errors were appropriate to the cause.

O8.4.5 Shorting of Electrical Terminals

Background

The NRC found three shorted terminal events that were identified in Problem Evaluation Requests 296-0222, 296-0692, and 297-0039. These events involved: the incorrect connection of test equipment during equipment troubleshooting causing an average power range monitor to be shorted to ground (296-0222 dated March 27, 1996); the inadvertent shorting of terminals with test leads while attempting to take voltage measurements during a calibration (296-0692 dated September 23, 1996); and the shorting and subsequent failure of a rod block monitor power supply caused by dropping a screwdriver into the panel during a calibration (297-0039 dated January 13, 1997). The NRC also noted that while two additional problem evaluation requests (296-0227 and 296-0293), which were referenced in Problem Evaluation Request 296-0692, identified similar events, they did not involve the taking of voltage measurements. Based on their review of these three events, the NRC concluded that the licensee did not broaden their corrective action efforts to solve the problem. As a result, the NRC concluded that shorted terminal events due to personnel errors continued to occur.

Inspector Followup

As documented in NRC Inspection Report 50-397/96-202, the inspectors noted that the three events involved different causes. In addition, the inspectors noted that Problem Evaluation Requests 296-0227 and 296-0293 involved circuit trips that occurred due opening of a panel and the removal of a panel and, therefore, did not involve shorted terminals.

The inspectors noted that the initiators of these events were diverse and that the only common cause was personnel errors. Based on these reviews and interviews, the inspectors determined that the licensee's corrective actions were appropriate. These included: suppling personnel with insulated tools; developing a written policy to require the use of insulated tools; insuring that new power supplies have terminal covers; and individual counseling regarding the use of proper tools for the job. Furthermore, the inspectors considered these corrective actions to be adequate and effective toward reducing the potential for personnel errors during such maintenance activities.

Conclusions

Actions to address the occurrence of shorting electrical terminals during the performance of maintenance or surveillance activities were adequate and effective toward preventing a recurrence of the events.

O8.4.6 Containment Atmospheric Control Design Deficiency

Background

Significant Problem Evaluation Request 297-0020 documented exceeding the technical specification limit for bypass flow from the drywell to the suppression chamber while operating containment isolation valves in the containment atmosphere control system to restore a nitrogen blanket in containment. This event occurred following an enhancement to the operating procedure to improve the operator's ability to repressurize the containment atmosphere control system using valve test switches. During their review of this problem evaluation request, the NRC found that two apparently similar events occurred in the past. The first event, which occurred in 1992 and was documented in Nonconformance Report (NCR) 292-0231 dated March 20, 1992, involved the removal of a valve test push button from the control circuitry to remove a single failure vulnerability. A new test switch was subsequently installed that was single failure proof. The second event, which occurred in 1993 and was documented in Problem Evaluation Request 293-0346 dated March 31, 1993, involved the discovery that performance of a periodic instrument surveillance test caused drywell to suppression chamber bypass flow to exceed technical specification limits. As the result of these reviews, the NRC concluded that the inadvertent introduction of a new initiator for the event through enhancement of the nitrogen blanket operating procedure was not something that could have been reasonably prevented through the problem evaluation request investigation that was conducted in 1993. The NRC also concluded, however, that these events were apparently caused by an uncorrected design problem.

Inspector Followup

The inspectors noted that the first event (Problem Evaluation Request 292-0231) did not involve an actuation of the containment atmospheric control system nor the initiation of drywell to suppression chamber bypass flow. The first event only postulated the potential for a single failure of the valve test push button. As a result, the licensee took actions to modify the test switch to assure that the single failure vulnerability was mitigated. While the second event did result in the initiation of a bypass flow condition, it involved a problem with the surveillance procedures. Since this surveillance was normally conducted during refueling conditions, it had not been a problem in the past. However, when the surveillance was performed during plant operations in an attempt to shorten outage times, it caused a bypass flow condition. The inspectors noted that the technical specification limits were not exceeded during this event. The third event involved a revision to an operating procedure to simplify operator actions during the

nitrogen phase of containment atmospheric control system operation. The procedure revision was inadequate, in that, when it permitted the use of the test switch to activate the required containment isolation valves, it did not assure that power was removed from those valves that could cause a bypass flow condition to occur. Though a bypass flow did occur, this flow was immediately terminated and the technical specification limiting condition for operation was not exceeded. Based on this review, the inspectors determined that only two of these events involved an actual bypass flow to occur, that these bypass flows did not exceed the technical specification limiting condition for operation, that these events were not the result of a design error, and that the events were caused by human errors pertaining to surveillance scheduling and the procedure revision process. The inspectors further determined that the corrective actions taken by the licensee were appropriate for the circumstances and adequate to prevent a recurrence of the events. These included: revisions to Procedures PPM 2.3.3.A and 2.3.3.B; a review of all procedures that involved the use of the test switch to assure that the required valves were disabled; counseling of involved personnel; the conduct of a "lessons learned" training for system engineers; and the addition of test switch operation precautions in the operator training program.

Conclusions

The corrective actions that addressed the inadvertent initiation of drywell to suppression chamber bypass flow were appropriate for the circumstances and adequate to prevent a recurrence of the events.

O8.4.7 Timely Initiation of Problem Evaluation Requests

Background

The NRC identified two instances where problem evaluation requests were not written to identify plant problems.

The first instance involved a failure to initiate a problem evaluation request by operations personnel when a quality assurance audit identified anomalous plant equipment operation. This instance was documented in Problem Evaluation Request 296-0489. While the problem evaluation request described three anomalous equipment operation instances, the NRC considered one to be the subject for a problem evaluation request. This instance involved the inadvertent start of the reactor recirculation pump during testing activities on June 10, 1996. The NRC concluded that the reactor recirculation pump start resulted in an unplanned entry into a technical specification limiting condition for operation and that this condition met the threshold for the initiation of a problem evaluation request.

The second instance, involving radiation protection department personnel, identified the use of gold cards in lieu of problem evaluation requests to identify plant problems and a continuing failure to correct an inadequate radioactive material labeling problem. The

use of the gold cards was documented in Problem Evaluation Request 296-0357 dated May 1996. The NRC noted that the licensee's corrective actions for this problem were not effective as evidenced by the issuance of Problem Evaluation Request 296-0839 dated December 1996. This second problem evaluation request again identified that gold cards were being used to identify problems and, in particular, documented that gold cards were used to identify the inadequate labeling of radioactive materials. The NRC noted that this problem evaluation request did not determine why previous corrective action from seven problem evaluation requests concerning inadequate labeling of radioactive materials was not identified as an adverse trend by the radiation protection staff through its independent review of the gold cards. The NRC concluded that the licensee's corrective actions were ineffective toward correcting the use of gold cards and the inadequate labeling issues.

Inspector Followup

Anomalous Plant Equipment Operation: The inspectors noted that operations personnel concluded that a problem evaluation request was not necessary for the inadvertent reactor recirculation pump start because the problem evaluation request threshold was not reached. However, the inspectors' review of Technical Specification 3.4.1.4/4.4.1.4 indicated that temperature differentials were required to be taken within 15 minutes prior to startup of an idle recirculation loop. Therefore, the inspectors determined that the event did result in the inadvertent entry into a technical specification limiting condition for operation and that the required temperature measurement surveillance was not performed prior to pump start. Furthermore, the inspectors noted that the lack of a problem evaluation request resulted in a failure to develop corrective actions that addressed such areas as: the initial failure to note the unplanned entry into a technical specification action statement; the failure of the testing circuit; whether similar testing needed to be performed for other system maintenance or modifications; and test procedure revision. The inspector's review of Procedure 1.3.12, "Problem Evaluation Request," Revision 24, indicated that the guidelines for initiation of a problem evaluation request stated, in part, that a problem evaluation request be issued for unexpected operating events and for deficiencies involving the technical specifications.

Radiation Protection Staff Problems: The inspectors reviewed Problem Evaluation Request 297-0485, issued for the improper storage and labeling of radioactive material containers. The inspectors found that Significant Problem Evaluation Request 297-0537 was written to document an adverse trend in the radiological protection program. Based on these reviews, the inspectors determined that the licensee was not fully effective at improving the radiation protection staff's knowledge of the gold card program and its relation to the problem evaluation requests. In addition, the inspectors noted that the licensee identified problems with correcting the inadequate radioactive material labeling problems. The inspectors were informed that the licensee hired a contractor to assist in the development of a root cause analysis for Problem Evaluation Request 297-0537. To control the labeling issues, the inspectors noted that the licensee initiated daily plant

walkdowns to identify inadequate labeling conditions until the root cause analysis and corrective actions for this problem could be developed and implemented.

The inspectors considered the failure to provide adequate corrective actions to identify the inadvertent start of the reactor recirculation pump to be contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion XVI. 10 CFR Part 50, Appendix B, Criterion XVI, requires nonconformances to be promptly identified and corrected. The failure to promptly identify and correct a nonconformance was considered to be the third example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI (50-397/9713-01).

Conclusions

There was a failure to issue a problem evaluation request that would have promptly identified and provided corrective actions for the inadvertent start of the reactor recirculation pump. This item was considered to be an example of a violation of 10 CFR Part 50, Appendix B. Corrective actions to control a lack of documentation of issues in problem evaluation requests and to resolve the inadequate labeling of radioactive materials were in progress.

O8.5 (Closed) Inspection Followup Item 50-397/96202-04: Corrective action program timeliness goals not met.

Background

As documented in NRC Inspection Report 50-397/96-202, the NRC noted that several problem evaluation requests were initiated to identify untimely resolution of problem evaluation requests and their associated corrective actions. Problem Evaluation Requests 295-0915 (August 1995), 296-0272 (April 1996), and 296-0735 (October 1996) were initiated to determine why several problem evaluation requests were not dispositioned within 30 days. Problem Evaluation Request 296-0709 (October 1996) was initiated to determine why significant problem evaluation requests were not dispositioned within 14 days. In addition, Problem Evaluation Requests 297-0027 and 297-0043 (both January 1997) were initiated to determine why corrective actions were not properly dispositioned or implemented when required.

Inspector Followup

The inspectors reviewed the reports that the licensee was using to track problem evaluation request resolutions and corrective action dispositions. The existence of these tracking reports was evidence that the licensee was aware of their problem evaluation request timeliness problems and was taking actions to correct the problems. The inspectors noted that the licensee issued weekly reports to all management personnel that designated the number of late problem evaluation requests and provided information regarding the problem evaluation requests that would be coming due during the next

week. The inspectors reviewed these reports for the weeks of July 7, 14, and 24, 1997, and noted that late reports and reports coming due during the next week were being dispositioned. The inspectors determined that this reporting system was effective at addressing and assuring that late problem evaluation requests were being resolved. The inspectors also reviewed the process that addressed overdue corrective action issues. The inspectors found that the licensee was tracking the overdue corrective actions through the use of a monthly trending report and departmental "annunciator panel" reports. As an example of this tracking activity, the inspectors found that Problem Evaluation Request 297-0046, issued on January 15, 1997, identified a trend in late corrective actions that was attributed to engineering.

Review of these reports by the inspectors indicated that the late report trend and the overdue corrective action trends were leveling off with some evidence of a decreasing trend. This was notable considering that the number of problem evaluation requests were increasing. To further improve their process, the licensee stated that they were implementing the use of electronic problem evaluation request resolutions. The use of this system would provide quicker response, a user friendly system, and provide an effective tracking system. In addition, they were considering revising Procedure PPM 1.3.12A, "Processing of Problem Evaluation Requests," to change the problem evaluation request disposition times from 14 days to a more realistic 30 days.

II. Maintenance

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Violation 50-397/9611-01: Failure to follow modification and scaffolding procedures.

Background

The NRC found three examples where plant modifications were performed using the technical evaluation process instead of the project modification record or minor modification processes as required by procedure. The NRC reviewed Plant Procedure Manual 1.4.1, "Plant Modifications," Revision 22, which was the governing procedure for the implementation of permanent plant modifications. The procedure allowed the use of a technical evaluation request to perform certain permanent plant modifications, which were considered to be equivalent changes. The NRC reviewed Technical Services Instruction TI 1.2, "Equivalent Change Evaluations," and determined that the equivalent change process was not to be used for complex plant modifications or when formal calculations were significantly impacted. Based on these procedures, the three examples were considered to be violations.

In addition, the NRC identified a violation where the licensee failed to follow the plant scaffolding procedure for unsecured scaffolding stored in safety-related plant areas. The

NRC reviewed Maintenance Programs and Procedure 10.2.53, "Seismic Requirements for Scaffolding, Ladders, Man-Lifts, Tool Gang Boxes, Hoists, and Metal Storage Cabinets," Revision 14. The NRC determined that the procedure required that all scaffolding be left in an acceptable seismic configuration and, if it did not meet procedural requirements, that an engineering evaluation be performed. There were no engineering evaluations performed for the unsecured scaffolding identified by the NRC.

Inspector Followup

The inspectors determined that the violations occurred due to procedure weaknesses, which were identified by the licensee as the root cause for the violations. The inspectors reviewed Plant Procedure Manual 1.4.1, "Plant Modifications," Revision 23, which the licensee revised to clarify when an equivalent change could be used in place of the modification procedure. The inspectors found that the revised procedure contained checklists and guidelines to aid in determining when an equivalent change could be used. In addition, the inspectors found that a 10 CFR 50.59 screening was required for each equivalent change. The inspectors determined that the procedure was adequate to preclude repetition of the violations.

The inspectors reviewed Maintenance Program and Procedure 10.2.53, "Seismic Requirements for Scaffolding, Ladders, Man-Lifts, Tool Gang Boxes, Hoists, and Metal Storage Cabinets," Revision 6, which the licensee revised to clarify scaffolding storage requirements. The inspectors found that the procedure contained the requirement to contact engineering if storage of scaffold components was found piled in safety-related areas of the plant. The procedure also required that engineering evaluate the condition and provide a 10 CFR 50.59 review for each request. In addition, discussions with the NRC resident inspector indicated that no additional scaffolding problems were identified during their plant tours.

The inspectors determined that the revised modification procedure was adequate to preclude repetition of this example of the violation. In addition, the inspectors determined that the revised scaffolding procedure provided clarification that would preclude repetition of this example of the violation.

III. Engineering

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Inspection Followup Item 397/9604-01: Use of Generic Letter 89-10 valve factors for operability determinations.

Background

During closure of the Generic Letter 89-10 motor-operated valve program, the NRC noted that the licensee had occasionally used less conservative valve factors than those justified under Generic Letter 89-10 to demonstrate the operability of a marginal valve. None of these examples were considered to constitute an immediate operability problem. However, the NRC was concerned that use of the lower valve factors was not adequately supported by test data and may under predict the thrust required to operate the valve under design basis conditions. In general, the licensee's motor-operated valve program did not specify minimum criteria (valve factors or other parameters) to be used when assessing operability.

Inspector Followup

The licensee revised Procedure MES-10, "Motor-Operated Valve Sizing and Switch Settings," Revision 0, via Temporary Change Notice 96-192, to include a definitive guide for evaluating motor-operated valve operability. The new operability criteria stipulated how valve factors, stem factor degradation, packing loads, rate of loading, and degraded voltage factors should be selected in the assessment of operability. The inspectors reviewed the revised criteria and considered the new operability criteria to be consistent with Generic Letter 89-10 and good engineering practice.

E8.2 (Closed) Unresolved Item 50-397/9611-02: Determination of the safety-related status of the reactor core isolation cooling system, which was downgraded from safety related to nonsafety related in 1985.

Background

The NRC identified that the reactor core isolation cooling system was downgraded from a safety-related to a nonsafety-related status in 1985, which changed the seismic qualification of the system from seismic Category I to nonseismic. This downgrade was performed due to a modification to the automatic depressurization system, which allowed the safety function of the reactor core isolation cooling system to be enveloped by this system. The NRC noted that Chapters 3, 5, and 7 of the FSAR specified that the reactor core isolation cooling system components were still considered seismic Category I and Table 3.2-1 of the FSAR specified that the reactor core isolation system was quality Class I and Seismic Class I. After discussions with the licensee, the NRC noted that this downgrade was not approved. This issue was referred to the NRC program office as

Task Interface Agreement 96-TIA-005 to determine whether the licensee's downgrade effort was appropriate.

Inspector Followup

The licensee submitted Safety Analysis Report Change Notice SCN 85-195, dated October 4, 1985, to the NRC to revise the FSAR and technical specifications to reflect the reactor core isolation cooling system downgrade from safety related to nonsafety related. The inspectors reviewed this submittal and found that the 10 CFR 50.59 safety evaluation, dated June 28, 1985, determined that there was no unreviewed safety questions associated with the downgrade. The submittal stated that the automatic depressurization system combined with the low pressure injection systems provided the same function previously accomplished by the reactor core isolation cooling system. The inspectors also noted that the plan was to delete the reactor core isolation cooling system from the technical specifications and Chapter 15 of the FSAR, where it was specified as the backup system to the high pressure core spray system. The inspectors reviewed the May 2, 1989, letter from the NRC to the licensee and found that the NRC denied the application for a technical specification amendment submitted in Change Notice SCN 85-195.

On January 31, 1997, in response to Task Interface Agreement 96-TIA-005, the NRC program office concluded that the downgrading of the reactor core isolation cooling system was unacceptable. This response stated that the reactor core isolation cooling system was a replacement for the high pressure core spray system during limited times when the high pressure core spray system was inoperable. Therefore, during this limiting condition for operation, as specified in Technical Specification 3.7.3, the reactor core isolation system was considered part of the emergency core cooling system replacing the high pressure core spray system. In addition, the reactor core isolation system was originally assumed to mitigate the consequences of the loss of all feedwater accidents in Section 15.2.7 of the FSAR and was considered to be a coping system for a station blackout event. Finally, the staff concluded that the safety-related function of the reactor core isolation cooling system was not enveloped by the automatic depressurization system since the automatic depressurization system was considered as a last resort system because of the transient effects associated with its actuation.

Based on the NRC determination that the reactor core isolation cooling system was safety related, the licensee prepared Problem Evaluation Request 297-0491, dated May 29, 1997, to determine the operability of the system and reclassify the system as safety related. The inspectors reviewed Revision 1 of the followup assessment of operability, which was part of the problem evaluation request. The followup assessment of operability determined that the system was operable but nonconforming. The system was determined to be nonconforming because the system was safety related and the

activities implemented following the reclassification in 1985 (e.g., modifications) were not in conformance with the original license requirements. The inspectors noted, however, that the licensee had maintained the technical specification requirements for the reactor core isolation cooling system, which included periodic testing. The inspectors also noted that Chapter 7 and Appendix 15A of the FSAR indicated that the reactor core isolation cooling system was used to mitigate the consequences of the control rod drop accident.

The inspectors noted that the followup assessment of operability contained an assessment of the changes that were made to the system components after the downgrade. The inspectors determined that the portions of the reactor core isolation cooling system required to maintain the integrity of the reactor coolant pressure boundary and to provide containment isolation remained safety related and that their classification was not changed. The remaining equipment was reclassified as nonsafety related. Documentation to support the seismic qualification of equipment that was designated as nonsafety related was not required nor maintained. The components reclassified to nonsafety related were not maintained to the requirements of a 10 CFR Part 50, Appendix B, quality program, but instead to an augmented quality program. The augmented quality program allowed parts and components to be purchased commercially (i.e., from a non-Appendix B supplier) and were not required to be dedicated.

The inspectors reviewed the inservice test program for the reactor core isolation cooling system to determine if any changes were made due to the downgrade. The inspectors found that the licensee revised the inservice test program in December 1994 when the program was upgraded for the second 10-year interval to the 1989 Edition of ASME Section XI. At this time, the licensee took advantage of the downgraded reactor core isolation cooling system and changed the program by deleting valves that were considered a part of the downgrade effort. The valves excluded from the inservice test program included Check Valve RCIC-V-11, a suction valve in line from the condensate storage system; Check Valve RCIC-V-086, a suction valve for the RCIC water leg pump; Check Valve RCIC-V-21, a miniflow valve from the main pump; and Motor-Operated Valve RCIC-V-59, a discharge valve from the RCIC pump. The inspectors reviewed testing for these valves and determined that while the valves were deleted from the program, they remained operable because they were being tested as a part of other surveillance testing activities. The inspectors also noted that containment isolation valve test requirements for some reactor core isolation cooling valves were modified to measure the close only function to ensure containment integrity, where previously their function had been to both close for containment integrity and open for reactor core isolation cooling injection. The inspectors reviewed the test procedures for testing the containment isolation valves and found that in 1985, Procedure 7.4.7.3.3, "Plant Operability Test," Revision 4, required that the containment isolation valves be stroked in both the open and closed direction to assure that stroke times were within the specified acceptance criteria as required by the ASME code. The inspectors noted that current Procedure OSP-RCIC/IST/Q702, "RCIC Valve Operability Test," Revision 1, required that the valves be stroked in both the open and closed direction, but only specified an

acceptance criterion for the closing direction. The inspectors found that there were six containment isolation valves that did not have an acceptance criteria for opening stroke-time testing. These valves included RCIC-V-13, head spray isolation valve; RCIC-V-19, minimum-flow to suppression pool isolation valve; RCIC-V-28, auxiliary cooling to suppression pool isolation valve; RCIC-V-31, suppression pool to RCIC suction; RCIC-V-40, turbine exhaust to suppression pool isolation valve; and RCIC-V-66, head spray isolation valve. The inspectors also noted that Valve RCIC-V-45, the turbine steam supply isolation valve, was no longer tested for either opening or closing stroke times.

10 CFR 50.55a(f) requires inservice tests of valves required for safety to assure that the valves comply with the requirements of Section XI of the ASME code. Section XI of the ASME Code requires that acceptance criteria be developed for valve stroking tests so that stroke-time degradation can be identified. The failure to develop appropriate acceptance criteria for the opening stroke-time testing for six reactor core isolation cooling system valves and the failure to test the stroke times for Valve RCIC-V-45 is considered to be an apparent violation (50-397/9713-02).

The inspectors reviewed the corrective actions required to reclassify the previously downgraded reactor core isolation cooling system components to safety related. The corrective actions were documented in Problem Evaluation Request 297-0491. The problem evaluation request identified 23 tasks that included establishing seismic qualification; establishing environmental qualification; evaluating previous procurements, substitutions, maintenance, equivalent changes, and plant modifications; and evaluating and revising the inservice test program. In addition, the inspectors reviewed the draft reclassification plan and the schedule for completion. The inspectors determined that the licensee planned to complete the reclassification by the end of 1997. The inspectors also determined that the reclassification plan was thorough.

The licensee stated that they were in the process of performing commercial grade dedication on 130 components or parts that had been purchased commercially and not through a 10 CFR Part 50, Appendix B, supplier. The inspectors reviewed five commercial grade dedication packages that the licensee had recently prepared. The inspectors concluded that the five packages were adequate. The inspectors reviewed eight modification packages that were prepared between 1984 and 1996. The inspectors found that for the modifications to the safety-related parts of the system, the components were purchased as safety-related components with seismic qualification. The inspectors found one modification, which was in the downgraded portion of the system. Modification 92-161 added a pressure tap to the lube oil pressure switch on the turbine skid. The inspectors found that there was no seismic analysis for this change in the modification package.

The inspectors questioned the risk significance of the reactor core isolation cooling system and how it was categorized in the Maintenance Rule program. The licensee stated that they considered the reactor core isolation cooling system to be a risk-significant standby system.

On December 23, 1997, the licensee responded to Task Interface Agreement 96-TIA-005 and provided additional information relative to the use of the reactor core isolation cooling system. This additional information indicated that the reactor core isolation cooling system was not a safety-related backup for the loss-of-feedwater event, was not an emergency core cooling system, and was not a coping system for the station blackout event. In addition, modifications to the automatic depressurization system allowed the system to envelop the functions of the reactor core isolation cooling system and provide controlled reactor depressurization. Therefore, the licensee concluded that the automatic depressurization system was not a last resort system. The NRC reviewed this response and agreed with the licensee's positions regarding these events. However, the NRC also noted that the licensee's response stated that the reactor core isolation cooling system should not have been downgraded without NRC approval because it was a backup to the high pressure core spray system for the control rod drop accident. The licensee also stated in this response that approval of the reactor core isolation cooling system classification downgrade was not docketed by the NRC.

10 CFR 50.59, "Changes, Tests, and Experiments," permits the licensee to make changes to the facility and to procedures as described in the safety analysis report without prior Commission approval, provided the change does not involve an unreviewed safety question. A proposed change shall be deemed to involve an unreviewed safety question if the probability of a malfunction of equipment important to safety may be increased.

The reactor core isolation cooling system was downgraded from safety related to nonsafety related without NRC approval. Since this system was a backup to the high pressure core spray system for mitigation of a control rod drop accident and applicable testing and quality standards were not maintained, the downgrade may have increased the probability of a malfunction of equipment important to safety. Therefore, this downgrade involved an unreviewed safety question and is considered to be an apparent violation of 10 CFR 50.59 (50-397/9713-03).

Conclusions

The reactor core isolation cooling system was downgraded from safety related to nonsafety related. While the system was found to be operable, it was also found to be nonconforming. The reclassification plan and schedule for returning the reactor core isolation cooling system to safety related were thorough and timely. As the result of

these downgrade activities, six reactor core isolation cooling valves were not being tested. The failure to test these valves was considered to be an apparent violation of 10 CFR 50.55a(f). Downgrading the system from safety related to nonsafety-related apparently increased the probability of a malfunction of equipment important to safety and was considered to be an unreviewed safety question. This was considered to be an apparent violation of 10 CFR 50.59.

E8.3 (Closed) Violation 50-397/9611-03: Failure to maintain plant design basis.

Background

The NRC identified one example of a violation where plant configuration control was not being maintained and two examples of the violation where the licensee failed to have design analyses for the installed plant configuration. The first example was identified when the NRC reviewed Technical Evaluation Request 96-0125. This technical evaluation request documented a modification to increase the clearances at the lever arm pivot for a valve operator by removing one of two washers. The licensee had not determined whether the new clearance met the vendor's clearance requirements. The two other examples of the violation were identified when the NRC reviewed calculations. Calculation CMR-96-0128 analyzed a welded connection for a standby liquid control system piping hanger but not the installed bolted connection. Calculation CMR-95-0292 covered an all carbon steel and an all stainless steel piping configuration, but did not cover the installed carbon/stainless steel piping configuration.

Inspector Followup

The inspectors determined that the licensee revised Calculation CMR-96-0128 to reflect the actual bolted field installation. In addition, the licensee revised Calculation CMR-95-0292 to reflect the as-built carbon/stainless steel pipe configuration. The inspectors also determined that the valve vendor concurred with the washer removal specified in Technical Evaluation Request 96-0125 and stated that, if the alignment at the lever arm pivot could not be corrected, it was acceptable to use only one thrust washer. The inspectors concluded that the licensee had performed adequate corrective actions for the three examples identified in the violation.

The licensee identified that the drawings were not revised to reflect the modified pipe hanger configuration identified in the violation and acknowledged that this was a weakness in the design process. To correct this weakness, the licensee revised Technical Services Instruction TI 1.2 to require tracking of document changes to ensure drawings were revised promptly to reflect plant modifications. The inspectors noted that Procedure EDP2.15, "Preparation Verification and Approval of Calculations," and EDP2.11, "Field Changes," were revised to require that whenever calculations were used to justify as-built configurations, sufficient information had to be provided to describe how the calculation applied to the field configuration and to justify that the calculation was still valid. Procedures EI2.8, "Generating Facility Design Change

Process," and EDP2.50, "Generating Facility Minor Design Change Process," were revised to require that whenever vendor information was used as a design input, the vendor information should be taken from published vendor documents or obtained in writing from the vendor. The inspectors also reviewed the records of training for design and system engineers that emphasized the importance of documenting the basis for design changes and vendor concurrence.

E8.4 (Closed) Unresolved Item 50-397/96201-01: Discrepancies between residual heat removal heat exchanger test analysis data and the FSAR.

Background

The NRC identified that the thermal performance monitoring test results for Residual Heat Removal Heat Exchanger 1B, conducted on March 3, 1996, indicated that the standby service water system gained 60 percent more heat than the residual heat removal system lost. Since the licensee determined that the maximum heat transfer rate was 11 percent, the 60 percent heat transfer rate mismatch was unacceptable. In addition, the NRC found that the licensee's evaluation used the standby service water system's higher heat transfer rate, which was nonconservative, and did not justify this use. The licensee attributed the error in heat transfer rates to defective instrumentation.

Based on the use of the higher heat transfer rate, the NRC concluded that the licensee had not evaluated the test results to assure that the test requirements were met. In addition, the NRC believed that the instrumentation used to measure temperature and flow data was suspected to be inaccurate prior to the performance of the test.

Inspector Followup

The inspectors discussed the results of the March 3rd test with licensee personnel and found that the test engineer suspected a problem with the ultrasonic flowmeter used to measure residual heat removal flow rate through the heat exchanger after the test had been performed. After the test, the licensee inspected the installation of the ultrasonic flow meter and determined that the instrument had not been installed properly to ensure coupling of the transducer to the pipe. Since the standby service water side of the heat exchanger used an accurate installed flow element, the licensee decided to use the less conservative standby service water heat transfer rate to complete the evaluation. Also, the inspectors found that the licensee performed an additional performance evaluation of the heat exchanger using the conservative heat transfer rate from the residual heat removal side. The purpose of this evaluation was to compare the projected test results to the minimum required heat removal rates. The lower residual heat removal side heat transfer rate and the design conditions contained in the FSAR were used to determine the most limiting design operating mode. The evaluation showed that the residual heat removal heat exchanger was capable of handling the design and licensing basis heat loads. Based on the evaluation, the licensee concluded that the heat exchanger was operable.

The inspectors reviewed Operating and Engineering Test Procedure 8.4.42, "Thermal Performance Monitoring of RHR-HX-1A and RHR-HX-1B," Revision 5, and noted a number of procedural improvements. The licensee revised the procedure to specifically define acceptance criteria, to require a functional test of the equipment prior to the start of the test, and to provide direction on performing the evaluation using the most limiting design conditions. The inspectors noted that the licensee expanded the test acceptance criteria to include a statement that the percent difference in the energy balance across the heat exchanger should be less than 10 percent or within the accuracy of the test instrumentation. In addition, the inspectors noted that the revised procedure required the analysis of the test results be compared with the design conditions, and have an independent engineering review. The inspectors also reviewed the test results of the March 28, 1997 performance tests and noted that differences in the heat transfer rates between the standby service water side and the residual heat removal side were within the acceptance criteria.

Conclusions

The licensee performed an adequate evaluation of the March 3, 1996, residual heat removal system test results and demonstrated that the results were within the design basis.

E8.5 (Closed) Unresolved Item 50-397/96201-02: Failure to periodically update the FSAR as required by 10 CFR 50.71(e).

Background

The NRC identified five examples where the licensee failed to update the FSAR.

The first example involved the use of design condition values for calculating the heat removal capacity of the residual heat removal heat exchangers. The calculation used a standby service water flow value of 6900 gpm, whereas, FSAR Table 9.2-5 listed a flow value of 7400 gpm. While the licensee justified the adequacy of the 6900 gpm flow value, the NRC determined that the licensee failed to update the FSAR to reflect the new flow value.

The second example involved the inclusion of an incorrect figure in the FSAR. Figure 7.3-10c, "Nuclear Boiler System FCD (Functional Control Diagram)," was inconsistent with General Electric Elementary Diagram 807E180TC. Figure 7.3-10c contained control logic seal-ins and permissives that did not exist in the elementary diagram. The NRC determined that the actual as-built plant logic wiring was consistent with the elementary diagram and not the FSAR functional control diagram.

The third example involved the in-place deactivation of the standby service water keep full system. This system was deactivated in October 1993, however, the NRC determined that FSAR, Section 9.2.7, was not updated to reflect this in-place deactivated status.

The fourth example involved inconsistencies between the flow values used in flow balance test procedures and the values listed in FSAR, Table 9.2-5. Specifically, Flow Balance Test Procedures 7.4.7.1.1.1, 7.4.7.1.1.2, and 7.4.7.1.1.3 used flow rates that were less than those listed in the FSAR for five components cooled by the standby service water system. While the licensee justified in their calculations that the flow values used in the test procedures were adequate, the NRC determined that the licensee failed to update the FSAR to reflect the actual flow values used.

The fifth example involved discrepancies between the FSAR electrical system description and electrical system calculations. Specifically, emergency diesel generator loads and direct current system (station battery) loads listed in the FSAR were inconsistent with the loads used in various design calculations. While the licensee justified in their calculations that the load value discrepancies did not affect system operability or reliability, the NRC determined that the licensee failed to update the FSAR to reflect the loading conditions for the emergency diesel generators and the direct current system.

Inspector Followup

Standby Service Water System Flow to the Residual Heat Removal Heat Exchangers: The inspectors interviewed personnel and reviewed Problem Evaluation Request 297-0042 to determine the reason that the FSAR and the plant procedures were not in agreement with respect to the standby service water flow to the residual heat removal system heat exchangers. The inspectors also reviewed completed Flow Test Procedures 7.4.7.1.1.1 and 7.4.7.1.1.2, Request For Technical Services 97-01-008, and a draft version of Licensing Document Change Notice Form (LDCN) FSAR-97-008. This review was conducted to determine if the values used in the flow test procedures were appropriate, if they involved any safety issues, and the corrective actions taken by the licensee. The inspectors noted that while FSAR, Table 9.2-5, documented a flow of 7400 gpm, the procedures provided an acceptable flow range of 6900 to 7400 gpm. This meant that a flow rate of 6900 gpm, which was less than the flow rate specified in the FSAR, could be considered acceptable. Further review by the inspectors indicated that from about 1986 to 1990 the FSAR listed a flow of 6900 gpm. However, as the result of a licensee conducted safety system functional audit on the standby service water system in 1990, the FSAR was revised to increase the flow to 7400 gpm. This increase was based on initial plant assumptions, which stated that the standby service water inlet temperatures from the spray pond was 95° F. However, further review by the inspectors indicated that the worst-case design basis accident condition inlet temperature from the spray pond was 88.7° F. Based on Calculation ME-02-92-245, the licensee demonstrated that a 6900 gpm flow rate was adequate for an inlet temperature of 90° F.

However, the inspectors also determined that this draft version of LDCN FSAR 97-008 did not clarify the confusion that was noted by the NRC team with respect to the multiplicity of design temperature values. As a result of the inspectors' observation, the licensee considered revising the licensing document change notice. The inspectors considered this to be an example of a lack of attention to detail when incorporating changes into the FSAR in that while one section of the FSAR was revised, another applicable section of the FSAR was not revised at the same time. Specifically, FSAR, Section 9.2.7.2, referred to a note in FSAR, Table 9.2-5, that was deleted in 1990. While the inspectors determined that the 6900 gpm flow was properly justified, they considered the failure to update the FSAR to be contrary to the requirements of 10 CFR 50.71(e).

Incorrect FSAR Figure: The inspectors reviewed the automatic depressurization system logic diagram and the elementary diagram. As the result of this review, the inspectors noted that Drawing 02B22-04, 23, 3, Sheet 3 of 6, "Nuclear Boiler System FCD," was identical to Figure 7.3-10c in Amendment 51 of the FSAR. The inspectors also noted that these diagrams included logic figures for "SEAL-IN 105 SEC AFTER INITIATION OF TDS (Timing Device)," "SEAL IN LOGIC 'C'," and "PERMISSIVE UNLESS LOGIC A & C RESET SWITCH IS IN 'RESET' POSITION." Through discussions with licensee personnel the inspectors noted that these logic functions did not exist on the plant elementary diagram and that the plant was properly wired in accordance with the elementary diagrams and not in accordance with the functional control diagrams. The inspectors determined that while the plant was properly wired in accordance with the plant elementary diagram, the failure to update the figure in the FSAR was contrary to the requirements of 10 CFR 50.71(e).

Deactivation of the Standby Service Water Keep Full System: The licensee informed the inspectors that while the standby service water keep full system was deactivated in 1993, they did not implement a FSAR change until November 11, 1996. This was confirmed by the inspector's review of LDCN FSAR-96-092. The inspectors determined that the failure to revise the FSAR within 24 months was contrary to the requirements of 10 CFR 50.71(e).

Standby Service Water System Flow Balances: The inspectors reviewed the Flow Balance Test Procedures 7.4.7.1.1.1 and 7.4.7.1.1.2 and noted the discrepancies between the procedures and Table 9.2-5 of the FSAR. The components that had incorrect flow rates were the low pressure core spray pump motor bearings, residual heat removal pump seal coolers, and the high pressure core spray diesel generator, diesel generator room coolers, and pump room cooler. The inspectors also noted that while the licensee's calculations supported the lower flows to these components, the failure to update FSAR Table 9.2-5 to reflect these lower flow rates was contrary to the requirements of 10 CFR 50.71(e).

Discrepancies Between the FSAR and Electrical System Calculations: The inspectors interviewed personnel and reviewed draft LDCN 97-000, LDCN FSAR-97-019, and LDCN FSAR-97-035 to verify that the FSAR discrepancies did not represent safety issues. The inspectors found that LDCN 97-000 made administrative FSAR changes, which included an update to FSAR, Table 8.3-15; LDCN FSAR-97-019 provided a FSAR correction to Table 8.3-18 to reflect the loading change from Distribution Panel E-DP-S1/1D to E-DP-S1/1F; and LDCN FSAR-97-035 revised FSAR Tables 8.3-4a, 8.3-4b, 8.3-5, 8.3-6, and 8.3-7 to be consistent with the battery loading profile that was updated in Calculation 02.05.01. The inspectors also found that the changes made by LDCN 97-000 represented another example of a lack of attention to detail when incorporating changes to the FSAR, in that while one section of the FSAR was revised and another section was not at the time. In this case, the text section of the FSAR documented a voltage range up to 242 kV, whereas, Table 8.3-15 still reflected a voltage range up to 240 kV.

These LDCNs represented issues in which the acceptance criteria in the surveillance procedures was inconsistent with the data presented in the FSAR and changes made to the FSAR were inadequate in that the changes did not correct all affected sections of the FSAR. The inspectors determined that the FSAR discrepancies did not involve any safety or operability issues and that the failure to update the FSAR were further examples of a 10 CFR 50.71(e) violation (the first two examples involved fire protection as discussed in Section O8.2 of this report).

The inspectors were informed that the licensee initiated a FSAR upgrade project. The licensee stated that development of this project was initiated in 1996 when the licensee identified problems with the accuracy of the FSAR through the performance of eight safety system functional audits during the 1988 to 1992 time period and through NRC inspection findings. The licensee further stated that the completion date for this project was August 1997. However, the licensee later determined that more time was needed to perform this upgrade and revised their estimates. This project was finally initiated on April 7, 1997, and had a projected completion date of March 6, 1998. Review of the schedules and milestones for this project by the inspectors indicate that it was about 20 percent complete and was being performed by contracting personnel. The inspectors also noted that this project will encompass a review of all FSAR chapters. Based on a review of this program, it appeared that the program will be effective and would have identified the issues identified by the NRC. The licensee has docketed this program in their response to the NRC's request for additional information pursuant to 10 CFR 50.54(f) dated February 7, 1997, and to the open items identified in NRC Inspection Report 50-397/96-202 dated June 16, 1997. Therefore, in accordance with Section VII.B.3 of the Enforcement Policy, the NRC is exercising discretion and is not taking formal enforcement action on these findings.

Conclusions

Multiple examples of FSAR inaccuracies were identified. While no safety issues or operability issues were identified, these multiple examples were indicative of a failure to update the FSAR. However, the implementation of a FSAR update program permitted the exercising of enforcement discretion in accordance with the revised enforcement policy.

E8.6 (Closed) Inspection Followup Items (50-397/96201-03; 50-397/96201-05; 50-397/96201-09): Design Basis Document discrepancies.

Background

The NRC identified errors between design requirement documents and the actual system design configurations. These errors included an omission regarding the backup power source for the residual heat removal pumps, an incorrect description of the function of the standby service water keep full pumps, which were abandoned in-place, but were still listed in the design basis document as an operable system (50-397/96201-03), a lack of detail regarding instrumentation and control requirements for the residual heat removal pumps (50-397/96201-05), and incorrect listing of the automatic depressurization system valves that were actuated from the remote shutdown panel (50-397/96201-09).

Inspector Followup

The inspectors reviewed records pertaining to the design requirement document program. The inspectors found that, as the result of the NRC findings, the licensee issued Problem Evaluation Request 297-0044 to address the specific issues. In addition, the licensee recently initiated a design requirements document upgrade program. The inspectors noted that this program plan was to review all 21 system level design requirement documents, which encompassed 29 nonsafety-related and 19 safety-related systems, and 6 topical level design requirement documents, which encompassed 11 safety-significant areas. Each system engineer was provided packages of design requirement documents for their assigned systems and the activity was being tracked by the licensee's plant tracking log. In the response to the open items identified in NRC Inspection Report 50-396/96-201, the licensee committed to complete this program by December 31, 1998.

E8.7 (Closed) Inspection Followup Item 50-397/96201-04: Plant procedure did not reflect the plant response to an under voltage condition.

Background

The NRC determined that Plant Procedure Manual (PPM) 4.7.1.9, "Loss of Power to SM-8," did not describe the actual plant response to the tripping of Residual Heat Removal Pumps 2B and 2C during an under voltage condition. The NRC also determined that plant operators were knowledgeable of actual plant response and that the licensee planned to revise the procedure to correct this omission.

Inspector Followup

The inspectors verified that the licensee revised Plant Procedure PPM 4.7.1.9 by adding Residual Heat Removal Pumps 2B and 2C to the list of breakers and equipment that trip on a SM-8 under voltage. In addition, the inspectors verified that Plant Procedure PPM 4.7.1.8, "Loss of Power to SM-7," was also revised by adding Residual Heat Removal Pump 2A and the low pressure core spray pump to the list of circuit breakers and equipment that trip on a SM-7 under voltage. Through personnel interviews, the inspector's also verified that the residual heat removal pumps and the low pressure core spray pump would automatically restart when power was restored to the busses if an initiation signal (e.g., an emergency core cooling system initiation signal) occurred. In addition, the inspectors concluded that since these pumps are usually not operating during normal plant operations, the absence of these pumps on the procedure's "Automatic Actions" listing did not have any effect on the operator's ability to cope with the loss-of-power conditions.

E8.8 (Closed) Unresolved Item 50-397/96201-07: Inadequate analysis of design pressure for the automatic depressurization system actuators.

Background

The automatic depressurization system was designed such that nitrogen was supplied to accumulators to keep the main steam safety relief valve actuators pressurized to 186 psig. The NRC found that the accumulators and main steam safety relief valve actuators had no pressure relieving device. Therefore, as the drywell temperature increased during accident conditions, the pressure within the accumulators and actuators would also increase and the overpressurizing of these components was possible. Under such accident conditions, the NRC postulated that the drywell temperature could reach 285°F and the pressure in the accumulators and actuators would increase from 186 psig to greater than 260 psig. The NRC also determined that even with the elevated pressure and temperature in the drywell, the pressure in the accumulators/actuators would remain within the design pressure of the equipment. However, the NRC also postulated that if operators actuated containment spray, pressure in the drywell would drop causing the temperature induced higher pressure in the accumulators/actuators to exceed the main

steam safety relief valve actuator design pressure of 250 psig. The NRC noted that this low drywell pressure condition was not recognized in the accident analysis. In addition, the NRC noted that Calculation 5.46.05, "Maximum and Minimum CIA (Containment Instrument Air) System Pressure," evaluated the minimum and maximum pressures to which the accumulators/actuators were subjected. While the calculation took credit for the high drywell pressure that reduced the pressure differential between the accumulators/actuators and the drywell, it did not address the low drywell pressure condition.

Inspector Followup

The inspectors found that based upon the NRC concern, the licensee performed a preliminary calculation which determined that under worst-case differential pressure conditions (i.e., the containment pressure would depressurize to 0 psig and the actuator would have an increased pressure due to the increased temperature affects) the actuator would be subjected to a maximum pressure of 277 psig. The licensee also determined that the accumulator and piping design pressure was 300 psig and the main steam safety relief valve actuator design pressure was 250 psig. Therefore, the actuator could be subjected to pressures that were in excess of the design pressure. However, the licensee determined that more precise calculations would probably show that since the temperature in the drywell was decreasing due to the containment spray, the temperature in the actuators would also be decreasing and that the 277 psig pressure would not be reached. The inspectors reviewed documentation from Crosby Valve, Inc., the manufacturer of the main steam safety relief valve actuators. The inspectors noted that the valve manufacturer was in the process of changing the actuator design pressure rating from 250 to 300 psig and that no changes to the actuator were required to meet this new pressure rating. The licensee stated that appropriate changes to design documentation would be made following completion of the design change evaluation. The inspectors noted that the licensee was in process of rerating the actuator design pressure to satisfy the NRC concern. The licensee stated that the scheduled completion date for the actuator rerate was October 15, 1997.

Conclusions

Appropriate actions to correct a new and previously unanalyized condition involving the potential overpressurizing of the main steam safety relief valve actuators were being taken. These actions indicated that the actuators were capable of withstanding the additional pressure and that design documentation would be changed to reflect the new design pressure ratings.

E8.9 (Closed) Inspection Followup Item 50-397/96201-08: Incomplete data for the main steam safety relief valve quencher and tail pipe support design.

Background

The NRC identified incomplete documentation to support the operating stresses for the main steam safety relief valve quencher supports and tail pipe supports. The NRC requested the source of the design stresses used for the quencher and tail pipe supports, however, the licensee was unable to retrieve this information. Calculation NE-02-89-18, Revision 2, established the maximum safety relief valve tail pipe stress level limit and the minimum safety relief valve reopening pressure. The NRC considered that while the methodology used in the calculation was adequate, it lacked design stress documentation.

Inspector Followup

The inspectors reviewed three draft calculation modification records, which the licensee developed in order to reassess structural design margins since they were unable to retrieve the source data used in Calculation NE-02-89-18. The licensee determined the piping-to-quencher support load using a detailed piping support model. The inspectors reviewed Request For Technical Services 96-12-012, dated December 17, 1996, which the licensee developed to update Calculation NE-02-89-18 and incorporate the revised design margins for the main steam safety relief valve quencher supports and the tail pipe supports. The inspectors noted that this information, in the form of preliminary calculations, indicated that the design margins for the supports increased from the original 3 to 13 percent. The licensee stated that the final calculations would be completed by September 17, 1997.

E8.10 (Closed) Unresolved Item 50-397/96201-10: Failure to implement the requirements of Regulatory Guide 1.62 for automatic depressurization system initiation.

Background

Through review of the General Electric Functional Control Diagram (FCD) 731E788, the NRC determined that the FCD did not agree with the as-built configuration for the manual initiation of the automatic depressurization system because the original design was inadvertently altered. The NRC postulated that a design error was introduced in 1985 as part of a modification to install an inhibit switch to prevent automatic actuation of the automatic depressurization system following a reactor vessel low water level condition. In addition, the NRC noted that operators were trained to activate this inhibit switch upon entry into the emergency operating procedures for a reactor vessel low water level condition. The NRC determined that the inhibit switch defeated the manual-initiate function shown on the FCD.

The NRC further postulated that this modified manual initiation was inconsistent with the manual-initiate operation described in Regulatory Guide 1.62, "Manual Initiation of Protective Functions." The NRC determined that three of the five guidelines listed in Regulatory Guide 1.62 were not met when the inhibit switch was initiated. Specifically, the operation now required more than the minimum number of operator actions, the group opening of the valves (i.e., 4 valves and then three valves together), as intended in the original design, was altered, and the seven valves now had to be opened individually in a sequential manner.

The NRC concluded that since Appendix C of the FSAR included Regulatory Guide 1.62 as a design commitment, the licensee was required to comply with the guidelines of the guide for manual initiation of a protective function.

Inspector Followup

Following the Three Mile Island (TMI) accident in 1979, the NRC required nuclear plant operators to make certain modifications to their plants to enhance safety. These modifications were called TMI Action Items. In the area of automatic depressurization, the BWR Owner's Group proposed methods to comply with the requirements of TMI Action Item II.K.3.18 concerning the depressurization system logic. As a part of granting the licensee's operating license, the NRC issued a safety evaluation report on December 29, 1983, which accepted the licensee's proposal to use one of the owner's group methods (Option 2) to meet the TMI action item. This option was to install manual inhibit switches in the automatic depressurization system. These inhibit switches were to be installed to modify the original design by preventing all seven automatic depressurization valves from opening simultaneously after a time delay. This safety evaluation report required the licensee to install this modification prior to restart from the first refueling outage. The licensee installed the modification during a May to June 1985 maintenance outage. On May 18, 1985, the licensee requested an amendment to the technical specifications to address the modified automatic depressurization system and the NRC approved the technical specification amendment (as Amendment 11) on June 23, 1985.

The inspectors reviewed the following documentation:

- "BWR Owner's Group Evaluation of NUREG-0737 Item II.K.3.18 Depressurization System Logic," dated February 1983;
- Safety Evaluation Report, Supplement 4, dated December 29, 1983;
- Request for Amendment to Technical Specifications for Automatic Depressurization System (ADS) Logic Modifications, License Condition 18, dated May 16, 1985;

- "Issuance of Amendment No. 11 to Facility Operating License NPF-21, WPPSS Nuclear Project No. 2," dated June 25, 1985;
- Amendment 36 to the FSAR dated December 1985;
- FCD 731E788;
- Elementary Diagram 807E180TC, "Auto Depressurization System";
- Problem Evaluation Request 296-0857 dated December 13, 1996; and,
- Letter dated September 24, 1997, "WNP-2, Operating License NPF-21 Inspection Report 96-201 Addendum: Response to Open Items."

The inspectors walked down the control room controls for the automatic depressurization system and discussed use of the emergency operating procedures with an operator regarding the use of the automatic depressurization system and the inhibit switches.

As the result of these reviews, the inspectors determined that the licensee's actions were consistent with Regulatory Guide 1.62 as modified by the changes required by the NRC to meet TMI Action Item II.K.3.18. During this review, the inspectors also noted that the licensee, in their response to NRC Inspection Report 50-397/96-201 dated June 16, 1997, stated for Item 96-201-10, that a design error existed and would be corrected in their next refueling outage. When this statement was questioned by the inspectors, the licensee responded that their response to that item was incorrect and would be corrected in an addendum to that response. On September 24, 1997, the licensee submitted an addendum to the June 16 response to the NRC. This addendum stated that their present design was consistent with Regulatory Guide 1.62 as modified by TMI Action Item II.K.3.18. In this letter the licensee also acknowledged that FCD 731E788 was incorrect and would be revised to match the as-built plant design. The inspectors also noted that Problem Evaluation Request 296-0857 was issued to correct the FCD.

Conclusions

The current design for the manual initiation of the automatic depressurization system was consistent with Regulatory Guide 1.62 as amended by the requirements of TMI Action Item II.K.3.18 and no wiring error existed. Functional Control Diagram 731E788 was not consistent with the as-built plant configuration.

E8.11 (Closed) Inspection Followup Item 50-397/96201-011: Inadequate design documentation for the standby service water system to demonstrate containment flooding capability.

Background

The NRC identified that a beyond-design-basis function of the standby service water system was to flood the reactor vessel and containment, if required, during the post loss-of-coolant accident period. The report identified that with the standby service water system in this lineup, the standby service water pump could run out resulting in insufficient cooling water flow to the Division II emergency diesel generator. The NRC noted in the report that the licensee had initiated preliminary evaluations that indicated the emergency diesel generator would receive adequate cooling water flow and standby service water pump run out would not occur.

Inspector Followup

The inspectors reviewed the licensee's preliminary calculation that indicated there was sufficient head to provide emergency diesel generator cooling when the standby service water system was in a containment flooding lineup. The licensee stated that a formal evaluation of this concern was in process and the scheduled completion date was September 1, 1997. The inspectors discussed the licensee's preliminary findings and noted that the emergency diesel generators would receive an adequate cooling water flow and that standby service water pump run out would not occur.

E8.12 (Closed) Unresolved Item 50-397/96201-12: Inadequate corrective action to implement high pressure core spray service water corrosion monitoring.

Background

The NRC identified that the licensee had not addressed corrosion monitoring of the high pressure core spray system standby service water loop after a pin hole leak in a socket weld on Loop B of the standby service water system vent line was identified. The NRC reviewed Performance Evaluation Request 295-1229, initiated due to the pin hole leak, and noted that the corrective actions included improved corrosion monitoring and water treatment programs, annual nondestructive examination wall thickness measurements at selected locations, and trend analysis of general corrosion. The NRC concluded that the corrective actions were incomplete since they only addressed Standby Service Water Loops A and B and did not address the high pressure core spray standby service water loop.

Inspector Followup

The inspectors discussed the failure to include the high pressure core spray standby service water loop in the corrosion program with the licensee and reviewed Problem Evaluation Request 295-1229. The inspectors noted that the licensee had not classified the problem evaluation request as significant because the small size of the leak did not affect system operability. In addition, the licensee stated that no leaks were found in the high pressure core spray standby service water loop and the only additional leak found in the standby service water loops was caused by cavitation instead of corrosion. However, based on the NRC findings, the licensee revised their corrective actions to include the high pressure core spray service water loop in the annual preventive maintenance program for wall thickness measurement. The inspectors reviewed the applicable work order that would implement this task and noted that the wall thickness measurement for the high pressure core spray standby service water loop was added to the program.

Conclusions

The lack of inclusion of the high pressure core spray service water loop in the corrosion program was appropriate considering the type of failure that occurred. In addition, the inclusion of the high pressure core spray standby service water system in the wall thickness measurement program was considered to be a proactive approach toward eliminating any future problems.

E8.13 (Closed) Inspection Followup Item 50-397/96201-13: Licensee to redevelop Calculation ME-02-96-28 to identify standby service water system potential for cavitation.

Background

The NRC identified that the licensee could not locate Calculation ME-02-96-28, which was referenced in Problem Evaluation Request 295-1002. The calculation documented an evaluation to determine potential locations for cavitation within the standby service water system.

Inspector Followup

In a discussion with the licensee, the inspectors determined that Calculation ME-02-96-28, "Evaluation of Cavitation Potential in the Standby Service System," Revision 0, had been misfiled and was available for review. The inspectors reviewed this calculation and found that the potential for cavitation existed at two flow elements. The inspectors noted that the licensee implemented a design change to increase the back pressure on the flow elements and eliminate the cavitation potential. The inspectors determined that the calculation was adequate.

E8.14 (Closed) Inspection Followup Item 50-397/96201-14: The fuel pool heat exchanger and the control room emergency chiller were excluded from the standby service water flow balance test.

Background

The NRC identified that the fuel pool heat exchangers and Control Room Emergency Chiller CCH-CR-1B were not included in the standby service water flow balance test. While this was considered to be a weakness, there were no safety concerns since calculations indicated that all served components would receive adequate standby service water flow.

Inspector Followup

The inspectors reviewed draft Operating and Engineering Test Procedure 8.4.81, "SW System Performance with FPC HX (Fuel Pool Cooling Heat Exchangers) Valved In." The inspectors determined that the draft test procedure now included the fuel pool heat exchangers and Control Room Emergency Chiller CCH-CR-1B as part of the flow balance. The inspectors noted that the heat exchanger test acceptance criterion was that the heat exchangers met their minimum design flows. The licensee stated that this new test would be performed, as a minimum, every 5 years. The first test was scheduled to be performed in September 1997. The inspectors determined that the licensee's corrective actions were adequate. These corrective actions included preparing a test procedure to include the heat exchangers in the flow balance test and providing a schedule for testing.

E8.15 (Closed) Inspection Followup Item 50-397/96201-15: Use of the FSAR instead of the source calculations to set the battery profile for the load test.

Background

During a review of the results for the battery profile load test, the NRC noted that licensee personnel relied on the load table in the FSAR instead of the load calculation to set the battery load profile. Based on the NRC observation, the licensee stated that they updated the FSAR whenever the battery load calculation was revised. However, the NRC noted during a review of Calculation 02.05.01 that the list of documents affected by the calculation did not include the FSAR load table.

Inspector Followup

The inspectors reviewed the applicable FSAR Table 8.3-7 and were informed that Calculation 02.05.01 would be revised to include the FSAR load table in the calculation's list of affected documents. In addition, instead of continuing the practice of using the FSAR as the battery profile source document as stated in their June 16 response letter, the licensee has decided to revise the applicable plant procedures used for battery

surveillance testing such that these procedures reference the dc load calculation as the battery load profile source. The licensee stated that the procedures and calculation will be revised by January 1, 1998, which is prior to the date that the calculation will be needed for the load profile test.

E8.16 (Closed) Inspection Followup Item 50-397/96201-16: Did not meet the guidance of Engineering Directorate Manual 2.15 concerning outstanding calculation modification records.

Background

During a review of the Engineering Directorate Manual 2.15, "Preparation, Verification and Approval of Calculations," Revision 2, the NRC noted that the procedure recommended that calculations be revised if five or more calculation modification requests (CMRs) are outstanding against a calculation. The NRC found evidence that three sampled calculations had more than five calculation modification requests outstanding against them. The NRC identified 77 CMRs against Calculation E/I-02-90-01, 29 CMRs against E/I-02-85-07, and 23 CMRs against Calculation E/I-02-87-02.

Inspector Followup

The inspectors reviewed Procedure 2.15 and noted that while Steps 1.2.3 and 4.5.3 of this procedure stated that the limit of CMRs was five, the procedure permitted more than five "plant implemented" CMRs to be outstanding against a calculation if the CMRs were authorized by the responsible supervisor/manager. The inspectors selected ten calculations with greater than five outstanding CMRs and reviewed these CMRs to determine if responsible supervisor/manager approval was obtained. This selection included Calculations E/I-02-85-07 and E/I-02-87-02. The inspectors also selected two calculations that had less than five CMRs to verify the accuracy of the licensee's CMR number tracking system. The inspectors verified that the selected calculation CMRs had the appropriate approvals. Based on this review, the inspectors determined that the licensee's activities were in accordance with Procedure 2.15.
The inspectors also reviewed a listing of calculations dated July 3, 1997, and found that 46 calculations had more than 5 CMRs. The inspectors found that 30 of these calculations had less than 10 CMRs. The remaining 16 calculation CMR breakdown was as follows:

Calculation	Number of CMRs
E/I-02-85-07	26*
E/I-02-87-02	18*
E/I-02-87-05	12
E/I-02-87-07	15
E/I-02-90-01	71*
E/I-02-92-12	24
FP-02-85-03	30
NE-02-85-19	15
TR-2512-1	11
2.05.05	15
2.06.20	26
2.07.03	25
5.49.50	22
5.49.51	13
5.49.52	11
5.52.07	12

*Note: The number of CMRs for these calculations were different from the numbers listed originally in NRC Inspection Report 50-397/96-201 due to the different dates that the data was obtained.

As the result of this NRC finding, the licensee reemphasized expectations to engineering personnel, which included that new CMRs for calculations that already have five changes against them, will not be accepted unless due dates were established, the dates entered into the plant tracking log, and an evaluation be performed to assure that the outstanding CMRs did not adversely affect the calculation. In addition, the licensee established an engineering team to self-assess their calculation process and controls.

The inspectors reviewed his self-assessment, which was completed on October 16, 1997. The inspectors noted that while the assessment identified numerous problems with the retrieving and handling of calculations and with the Controlling Procedure 2.15, it did not determine if it was necessary to verify the effect of the numerous CMRs on the technical content of the existing calculations. The potential for numerous CMRs affecting the technical content of the calculations is considered to be a inspection followup item (50-397/9713-04).

Conclusions

While Engineering Directorate Manual 2.15 was properly implemented, actions were being taken to further control the number of calculation modification records for plant calculations. A self-assessment performed by the licensee did not identify if the

outstanding calculation modification records potentially affected the technical content of the calculations.

E8.17 (Closed) Inspection Followup Item 50-397/96202-03: Problems were identified on gold cards when they should have been identified as problem evaluation requests.

Background

The licensee developed the gold card system to identify human performance issues, that if left uncorrected, could contribute to a significant event. In NRC Inspection Report 50-397/96-202, the NRC found that two gold cards, 4207 and 4727, contained potential engineering or hardware issues. Therefore, the NRC considered that problem evaluation requests, instead of gold cards, should have been issued to identify these plant problems.

Inspector Followup

The inspectors found that Problem Evaluation Requests 296-0732 and 296-0869 were written to address the issues that were the subject of gold cards 4207 and 4727. The inspectors noted that these problem evaluation requests were written prior to issuing the gold cards. In addition, the inspectors determined that the gold cards in question were properly written to track human performance issues on the identified problems. The inspectors reviewed five additional gold cards and determined that the cards were appropriately written in accordance with the licensee's program. The inspectors determined that the gold card system was properly implemented.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors conducted an onsite exit on August 2, 1997, to present the preliminary inspection results. An additional exit, conducted by telephone on January 12, 1998, presented the final inspection results to members of licensee management. The licensee acknowledged the inspection findings.

No proprietary information was identified by the licensee.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

B. Adami, Engineer
R. Barbee, Manager, System Engineering
G. Brastad, Consulting Engineer
D. Brown, System Engineer
R. Brownlee, Licensing Engineer
R. Chaudhuri, Engineer
D. Coleman, Supervisor, Regulatory Services
J. Gearhart, Manager, FSAR Upgrade
G. Gelhaus, Assistant to Engineering General Manager
P. Harness, Supervisor, Engineering
V. Harris, Assistant Maintenance Manager
J. Hunter, Manager, Radiation Protection
D. Mand, Manager, Design/Projects
M. Monopoli, Manager, Operations
J. Muth, Supervisor, Quality Support
J. Peterson, Engineer
J. Swailes, Engineering General Manager
R. Webring, Vice President, Operations Support

INSPECTION PROCEDURE USED

92903 Followup of Engineering Issues

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-397/9713-01	VIO	Corrective actions were not adequate to prevent recurrence of conditions that were adverse to quality.
50-397/9713-02	APV	Failure to maintain acceptance criteria and maintain testing of reactor core isolation cooling system valves as required by 10 CFR 50.55a(f).
50-397/9713-03	APV	Potential unreviewed safety question due to the failure to obtain NRC approval prior to downgrading the reactor cooling isolation system.

50-397/9713-04	IFI	The affect of excessive CMRs on the technical content of calculations.

Closed

50-397/9604-01	IFI	Use of Generic Letter 89-10 valve factors for operability determinations.
50-397/9611-01	VIO	Failure to follow modification and scaffolding procedures.
50-397/9611-02	URI	Determination of the safety-related status of the reactor core isolation cooling system which was downgraded from safety-related to nonsafety-related in 1985.
50-397/9611-03	VIO	Failure to maintain plant design basis.
50-397/9611-04	VIO	Failure to implement adequate and timely corrective actions.
50-397/9611-05	VIO	Failure to implement a Nuclear Safety Assurance Division procedure.
50-397/96201-01	URI	Discrepancies between residual heat removal heat exchanger test analysis data and the Final Safety Analysis Report.
50-397/96201-02	URI	Failure to periodically update the Final Safety Analysis Report as required by 10 CFR 50.71(e).
50-397/96201-03	IFI	Design Basis Document discrepancies.
50-397/96201-04	IFI	Plant procedure did not reflect the plant response to an under voltage condition.
50-397/96201-05	IFI	Design Basis Document discrepancies.
50-397/96201-07	URI	Inadequate analysis of design pressure for the automatic depressurization system actuators.
50-397/96201-08	IFI	Incomplete data for the main steam safety relief valve quencher and tail pipe support design.
50-397/96201-09	IFI	Design Basis Document discrepancies.
50-397/96201-10	URI	Failure to implement the requirements for Regulatory Guide 1.62 for the automatic depressurization system initiation.

50-397/96201-11	IFI	Inadequate design documentation for the standby service water system to demonstrate containment flooding capability.
50-397/96201-12	URI	Inadequate corrective action to implement high pressure core spray service water corrosion monitoring.
50-397/96201-13	IFI	Licensee to redevelop calculation ME-02-96-28 to identify standby service water system potential for cavitation.
50-397/96201-14	IFI	The fuel pool heat exchanger and the control room emergency chiller were excluded from the service water flow balance test.
50-397/96201-15	IFI	Use of the FSAR instead of the source calculations to set the battery profile for the load test.
50-397/96201-16	IFI	Did not meet the guidance of Engineering Directorate Manual 2.15 concerning outstanding calculation modification records.
50-397/96202-01	URI	Failure to prevent the recurrence of significant conditions that were adverse to quality.
50-397/96202-02	URI	Two examples where significant problem evaluation requests failed either to provide a root cause analysis or to provide a root cause analysis of sufficient depth.
50-397/96202-03	IFI	Problems were identified on gold cards when they should have been identified as problem evaluation requests.
50-397/96202-04	IFI	Corrective action program timeliness goals not met.

DOCUMENTS REVIEWED

PROCEDURES

Number	Title
PM 1.10.8	Nuclear Safety Assurance Assessments
SWP-ASU-01	Evaluation of Programs, Processes, and Suppliers
10.2.53	Seismic Requirements for Scaffolding, Ladders, Man-Lifts, Tool Gang Boxes, Hoists and Metal Storage Cabinets
15.1.13	Fire Suppression Systems Tamper Switch Operability

15.1.18	Fire Suppression Systems Valve Alignment
3.3.1	Master Startup Checklist
2.8.7	Fire Protection System
1.4.1	Plant Modifications
4.7.1.8	Loss of Power to SM-7
4.7.1.9	Loss of Power to SM-8
7.4.7.1.1.1	Standby Service Water Loop A Valve Position Verification
7.4.7.1.1.2	Standby Service Water Loop B Valve Position Verification
7.4.7.1.1.3	High Pressure Core Spray Standby Service Water Loop Valve Position Verification
TI 1.2	Equivalent Change Evaluations
EDP 2.15	Preparation verification and approval of calculations
E 2.8	Generating facility design change process
EDP 2.50	Generating facility minor design change process
EDP 2.11	Field changes
1.3.12	Problem Evaluation Request (PER)
1.3.12A	Processing of Problem Evaluation Requests (PER)
1.3.48	Root cause analysis
8.4.81	SW system performance with FPC HX valved in
8.4.42	Thermal performance monitoring of RHR HXs
7.4.7.3.3	RCIC operability test
OSP-RCIC/IST-Q702	RCIC valve operability test
OSP-RCIC/IST-Q701	RCIC operability test

TM-2043	Augmented quality requirements
EDP 2.41	Classification of structures components and subcomponents

PROBLEM EVALUATION REQUESTS

Number	Title
292-0231	Valve test push buttons open recombiner isolation valves.
293-0346	Pressure suppression bypass leakage in excess of technical specification allowable during CAC surveillance and possible internal flooding of CAC.
295-1002	Leak discovered on bottom of SW A line
295-1229	Pin hole leak found in SW vent line
296-0119	The motor-pump coupling for AC powered standby lube oil circulation pump DLO-P-3B2 was found to be failed during investigation of a low lube oil pressure annunciator.
296-0489	Threshold for writing a PER.
296-0639	Temporary stock piles of scaffold components
296-0649	PER written on findings from July 1996 engineering inspection
296-0857	ADS Functional Control Diagram 02B22-04, 23, 3 Rev 18 shows two seal-in's in each logic string, but only one is implemented in Elementary 02.
296-0285	Adverse trend in valve and switch mispositioning
296-0299	On 4/24/96 while performing MOVATS base-line test - WO RK1603 it was discovered that Wire 2M8B-502 (white) was landed on Limit Switch 1 and Wire 2M8B-401 (black-2) was landed on Limit Switch 1-C.
296-0362	During release of CO 960402261 on CFD 1E & 1F, water was noted coming out of condensate piping on T441.
296-0364	I&C was working WOT YG3903 on RCIC-PCV-15 and required no clearance order.

296-0382	SPTM-TE-10 as found wiring does not match top tier drawing EWD-251-004.
296-0415	Two clearances were not accepted prior to working on MS-V-172A/B.
296-0428	Work order #WF3301 was worked without personnel signing on to the danger clearance order (#96-01-0135).
296-0453	Loss of power occurred on Division 1 ARI during performance of PPM 8.3.361, ATWS-ARI functional test.
296-0497	A low level condition occurred in the main condenser hotwell due to a clearance order.
296-0587	Two potential violations were identified in the NSAD (ISEG) area during the NRC engineering inspection.
296-0650	A laborer cleaned sump T-2 with the work package for the job at status 40.
296-0869	Service water pump SW-P-1A tripped during
296-0351	Clearance order 96-04-0402 should have tagged pump control switches for sump 5-7, EDR-P-18A and the breakers for these pumps.
296-0537	During swing shift the production reactor operator found a work order task had been added to clearance order 96-02-0074 paperwork without a proper second level review of the add on sheet.
296-0775	Industrial safety issue from working two independently planned work packages on components associated with the same system.
296-0519	Document adverse trend in PERs.
296-0680	The orange/black conductor of cable BRR-9228 is landed at TB2-8 in E-SH-1D instead of at TB2-12, as shown on EWD 3E022.
296-0686	The black conductor of cable AIVD-9086 was found terminated on the wrong limit switch at CAC-EHO-FCV/4A limit switch enclosure during conduct of WOT ZR4401 to correct faulty TDAS valve position indication for this valve.

296-0688	Correct the meeting minutes for CNSRB Meeting #96-05 to correctly reflect that safety evaluation #95-095 was reviewed.
296-0690	During performance of PPM 8.9.1, HCU scram solenoid pilot valve replacement and electrical checks. The power supply leads into the SSPV electrical termination box for CRDSPV117/2215 were found reversed.
296-0692	As the craft performed WO BSM90, terminals 3 & 4 were shorted out which cleared the fuse F 24-2 located a E-DP-S1/1F, circuit 19, and damaging the edge connector of the relay case.
296-0693	This PER is issued to document a trend, based on the review of five PERS listed below which address wiring termination problems.
296-0711	Technicians found vent valve CRD-V-157D partially open. This valve's normal position is closed.
296-0780	XN7101 SGT-FT-1A2 loop cal. The wiring to SGT-FS-1A2 alarm B was found wired to contacts 13 and 14, the prints show they should be 11 and 12.
296-0782	Three wiring problems found in carbon bed heater No. 1 control box.
296-0832	Surveillance PPM 7.1.2 steps improperly N/A'd.
297-0016	Service water and diesels rendered inoperable for work order without a voluntary entry into technical specifications.
297-0020	Technical specification bypass leakage exceeded during performance of PM 2.3.3A, Section 5.5.
297-0035	HPCS diesel generator tripped on reverse power immediately after paralleling to the SM-4 bus.
297-0039	B RBM power supply failed when a screwdriver was dropped into the drawer.
297-0042	FSAR Tables 6.2-2 and 9.2-5 appear to conflict with PPMs 7.4.7.1.1.1 and 7.4.7.1.1.2 for the minimum SW flow to the RHR heat exchanger.
297-0044	Discrepancies were identified in the design requirements documents for the ADS, RHR, and SSW systems.

297-0055	CRD found out-of-position during PPM 7.4.1.3.1.2 position verification steps.
297-0070	While performing WO CZ501 it was discovered that the wrong type relay was installed under WO ZK4401 for K1.
297-0071	RHR-V-176B found open when danger tagged shut.
297-0072	An adverse trend of human performance problems have occurred recently.
297-0073	Apparent tagging error discovered.
297-0092	Found DMA-FN-21 switch in mid-position.
297-0116	There is an adverse trend in the number of inadequate clearance orders being prepared by personnel at WNP2.
297-0161	Hold down clamp has stripped threads
297-0157	WO BTV017 was to install additional monitoring on the ASD drive. Test point FBAR was misconnected to FCA, due to misidentification of label.
297-0414	During PMT of HD-MO-15C WO DCR7 and DGP6, the actuator's torque switch failed to stop the valve motion. Torque switch miswired.
297-0437	During performance of the loop seal flush of PPM 2.11.17, a valve was found not per the lineup in Step 7.3.1 and prohibited the flush.
297-0485	Errors found in storage and marking of radioactive material containers on the radwaste building 507' elevation.
297-0537	Recent PERs suggest a potential lack of understanding of portions of the radiation protection program.
297-0546	While attempting to shift to the CAS "B" dryer set, relief valve on CAS-AR-1B lifted due to no flow path through the "A" or "B" CAS dryers.
297-0582	During testing, the DFWLC logic was found to have the control system trouble alarm point in override.
297-0663	CIA-PCV-2B seal wire was found broken and stem lock nut loose.

TECHNICAL EVALUATION REQUESTS

Number	Title
97-0093-0	Interference between flow controller and pipe hanger
97-0087-0	Condensation in pipe causing corrosion problems
97-0029-0	Substituting relief valves
96-0213-0	Small bore pipe lines require removal of flanges
94-0306-0	Substituting sst piping for carbon steel
96-0004-0	Valves were identified to have a potential for not opening

CALCULATIONS

Number	Title
RCIC-1484-1	Qualification of new sst piping
CMR 96-0245	Analyze pipe system as modified by TER 94-0306
CMR 96-0244	Qualify support per as-built information
ME-02-96-28	Evaluation of cavitation potential in the SW system
NE-02-89-18	Safety relief valve variables
CMR-92-0192	Pressure limits for ADS accumulators
CMR-94-1154	Effects of reactor power on CIA system pressure
5.46.05	Maximum CIA system pressure
CMR-94-0348	This CMR revises the static loading information for MC-7A and MC-8A due to the affect of BDC 91-0438-0A
E/I-02-87-02	480V MCC Load Data for LOCA Operation
E/I-02-85-07	480V MCC Load Data for Normal Full Load Operation

DESIGN CHANGES

Number	Title
PMR 96-0133-0	Install restricting orifice in SW line
PMR 95-0268-0	Remove the electronic overspeed trip from the RCIC system
PMR 93-0082-0	Correct system level analysis

PMR 84-0623-0	Provide direction to delete motor operator
PMR 92-0161-0	Replace turbine lube oil alarm pressure switch
PMR 96-0046-0	Replace cap on the nipple with a valve
PMR 84-0331-0	Rework hanger
PMR 94-0631-0	Void calculation
PMR 87-0146-0	Redesign operator to removable type design
PMR 89-0397-0	Install pressure indicator to RCIC test return line

SAR CHANGE NOTICE FORMS

Number	Title
90-119	Update Table 9.2-5 to reflect the heat loads used in the thermal performance analysis for the ultimate heat sink.
95-044	Revise surveillance testing and inspection frequencies in FSAR Appendix F, Section F.5.

LICENSING DOCUMENT CHANGE NOTICE FORM

Number	Title
FSAR-96-092	Changed the description of the SW keepfill subsystem to indicate that the subsystem has been deactivated and spared in place.
LDCN-97-000	Annual LDCN to include administrative type corrections, drawing and figure updates. (DRAFT)
LDCN-FSAR-97-019	FSAR Table 8.3-18 shows that DP-S1-1D supplies control power to several switchgears that are actually supplied by DP-S1-1F.
FSAR-97-035	Update the FSAR system load tables (duty cycles) to those defined in the Battery Sizing Calculations: 2.05.01/rev 9 (Div-1/-2, 125 & 250 VDC) and E/I-02-85-02/rev 1 (Div-3, 125 VDC) as revised by their respective calculation modification records (CMR).
LDCN-FSAR-97-008	The tabulations in Table 9.2-5 are being modified to reflect changes in plant usage of equipment. (DRAFT)

MISCELLANEOUS

Number	Title
54314106	Dedication package for globe valves

60117050	Dedication package for actuators
54403013	Dedication package for relief valves
25506824	Dedication package for screw lock vacuum pump
56507934	Dedication package for piston seal

CNSRB Meeting Minutes 96-062

Information and schedules for the FSAR Upgrade Project

Engineering Calculation Self Assessment dated October 1997

Gold Card 4744, ...found CO-V-2A out of normal Vol 2 lineup

CATEGORY 2

REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

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TAYLOR,G.J. Southern California Edison Co.

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