Reference R

August 20, 1999

Mr. Guy G. Campbell
Vice President - Nuclear
FirstEnergy Nuclear Operating Company
Davis-Besse Nuclear Power Station
5501 North State Route 2
Oak Harbor, OH 43449-9760

SUBJECT: DAVIS-BESSE INSPECTION REPORT 50-346/99009(DRP)

Dear Mr. Campbell:

On August 2, 1999, the NRC completed an inspection at your Davis-Besse site. The enclosed report presents the results of that inspection.

The plant was operated in a conservative manner throughout the inspection period. The decision to ensure the functionality of the startup feedwater pump after receiving information that it would provide a substantial benefit to mitigate the consequences of a loss of feedwater accident was a good example of conservative decision-making. Examples of inattention-to-detail by operators concerning the reasons for computer point alarms and by electrical maintenance personnel during work on heat trace equipment detracted from the otherwise good performance during this inspection period.

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

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if you choose to provide one, will be placed in the NRC Public Document Room.

Sincerely,

/s/ T. J. Kozak

Thomas J. Kozak, Chief
Reactor Projects Branch 4

Docket No. 50-346
License No. NPF-3

Enclosure: Inspection Report 50-346/99009(DRP)

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No: License No:	50-346 NPF-3
Report No:	50-346/99009(DRP)
Licensee:	Toledo Edison Company
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 N. State Route 2 Oak Harbor, OH 43449-9760
Dates:	June 23 - August 2, 1999
Inspectors:	K. Zellers, Senior Resident Inspector S. Campbell, Senior Resident Inspector, Fermi
Approved by:	Thomas J. Kozak, Chief Reactor Projects Branch 4 Division of Reactor Projects

EXECUTIVE SUMMARY

Davis-Besse Nuclear Power Station
NRC Inspection Report 50-346/99009(DRP)

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a six-week period of resident inspection.

Operations

- The facility was operated in a conservative manner and no operator-initiated events occurred during the inspection period (Section O1.1).
- The inspectors concluded that operators were not fully cognizant of the reasons for all computer points which were in alarm and the relatively large number of computer point alarms tended to mask the significance of individual alarms (Section O1.2).
- The inspectors concluded that the Company Nuclear Review Board (CNRB) was an effective tool for improving licensee performance (Section O7.1).

Maintenance

- Overall, the plant was maintained in an effective manner. Management considered risk in scheduling maintenance activities and operators were informed of maintenance in progress. However, the inspectors identified that electrical maintenance personnel did not consistently implement plant management's expectation to use three-part communications during surveillance testing activities (Section M1.1).
- Jumpers used for a high risk activity (anticipatory reactor trip system testing) were not verified to be properly installed prior to the test. Inadequate jumper installation has resulted in several industry events and, in this case, if the jumpers had been improperly installed, a plant trip would most likely have occurred during the test. The licensee indicated that an evaluation of ways to ensure that jumpers were adequately installed would be conducted (Section M1.2).
- Electrical maintenance personnel worked on the wrong heat trace equipment on two separate occasions because of poor self-checking work practices. The root cause investigation was well documented and the proposed corrective actions should result in better overall maintenance department performance (Section M1.3).
- Overall, maintenance and operations personnel effectively removed, tracked and coordinated the EVS Train 1 maintenance activity while making reasonable efforts to manage risk (Section M1.4).
- The inspectors concluded that plant management conservatively tracked equipment out-of-service time and effectively ensured that outage times were minimized by providing the necessary resources to perform equipment maintenance and resolve emergent issues in a timely manner (Section M2.1).

Engineering

- Station management exhibited a commitment to nuclear safety when they took measures to ensure the startup feedwater pump would be available for accident mitigation functions, even though no regulatory requirement existed to do so (Section E2.1).

Plant Support

- Through system flushes, the licensee effectively reduced the dose rates associated with decay heat removal system train 1 (Section R1.1).

Report Details

Summary of Plant Status

The plant operated at nominally 100 percent throughout the inspection period, except for brief periods of time at about 95 percent power for equipment testing.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The licensee operated the facility in a conservative manner. Problems were brought to the attention of appropriate levels of management. Operators were aware of plant conditions and identified degraded conditions for resolution, with minor except as noted in Section O1.2 of this report. Plant status, evolutions in progress, and planned activities were effectively communicated during shift turnovers. No significant operator-initiated events occurred during the inspection period.

01.2 Operator Awareness of Computer Point Alarms (71707)

Computer point alarms provide a low threshold indication to operators of abnormal plant conditions that require followup, but do not require entry into an alarm procedure. During control room observations, the inspectors noted that a relatively large number of computer points were in alarm. However, when the control room operators were questioned on the reason for certain alarms, the operators could not provide an explanation. For example, operators were not aware of the reason for a reactor coolant system (RCS) flow computer point alarm and they did not confidently explain the reason for two other computer point alarms (high cold leg temperatures and low hot leg temperatures). Subsequently, operators submitted requests to engineering and maintenance personnel to have the alarms resolved. Additionally, the monitor that displayed the computer point alarms did not meet plant management's goal of having all of the alarms displayed at the same time. Management indicated that many alarms were caused by hot weather and that efforts to resolve the problems associated with the alarms were underway. The inspectors concluded that operators were not fully cognizant of the reasons for all computer points which were in alarm and the relatively large number of computer point alarms tended to mask the significance of individual alarms.

O2 Operational Status of Facilities and Equipment

O2.1 System Walkdowns (71707)

The inspectors walked down the accessible portions of the following engineered safety features (ESF) and important-to-safety systems during the inspection period:

- Emergency Diesel Generators 1 and 2
- Auxiliary Feedwater Trains 1 and 2
- Service Water Trains 1 and 2

- Low Pressure Injection Trains 1 and 2
- High Pressure Injection Trains 1 and 2

No substantive concerns were identified during the walkdowns. Major flowpaths were verified to be consistent with plant procedures/drawings and the Updated Safety Analysis Report (USAR). Pump/motor fluid levels were within their normal bands. Only minor oil and fluid leaks were noted on occasion. However, some minor pump water leaks were not identified with a material deficiency tag. Also, a screenwash pump room 4160 volt cubicle had water dripping on it from a rainstorm. The inspectors informed licensee management of the minor concerns identified during the walkdowns and the issues were resolved appropriate to the situation.

O2.2 Equipment Performance During Hot Weather (71707)

In late July, ambient air temperatures routinely exceeded 90 degrees Fahrenheit (^{0}F) and the inspectors tracked the performance of equipment during this time frame. Invertor YVA, which provides the normal power to bus YAU, which is important to maintain mode 1 operations, had to be transferred to the alternate power supply on two separate occasions, because the static transfer switch malfunctioned. The apparent cause for the malfunctions was temperature-related failures of the inverter circuit cards. This invertor is scheduled to be replaced during the 13th refueling outage but will be evaluated for earlier replacement due to its recent unreliability. Also, the ultimate heat sink (UHS) temperature rose to 83.7 ^{0}F on July 31. The TS limit of 85 ^{0}F required a plant shutdown. The licensee had been in the process of evaluating the operability of plant equipment and concluded that all safety-related equipment would remain operable with an UHS temperature of 90 ^{0}F. Therefore, the licensee submitted a license amendment request to raise the TS limit to 90 ^{0}F. This request was under review at the end of the inspection period. High temperatures on some balance of plant motors were compensated for with temporary fans. High containment temperatures that approached the TS limit of 120 ^{0}F were addressed by directing more water flow through the containment air coolers. This was done by raising the temperature setpoint on the component cooling water system, which caused less water to flow through the component cooling water heat exchangers and therefore more water to flow through the containment air coolers. The hot weather did not cause any plant transients or significant equipment problems. The inspectors concluded that, overall, plant equipment operated well during the recent hot weather spell.

O2.3 RCS Leakage Detection System Problems (71707)

The inspectors reviewed the licensee's efforts to resolve frequent low flow alarms on the containment atmospheric particulate and gaseous radiation monitor system. Engineering and maintenance personnel did extensive testing of the system, but did not identify any functional problems with the system. The licensee noted that system filters had accumulated a dark colored particulate (along with a white colored boric acid residue) and independent testing determined that the particulate was primarily iron oxide (a corrosion product). The results of this determination were documented on condition report (CR) 1999-1300. The licensee postulated that the corrosion particulate was the cause of the low flow alarms. At the end of the inspection period, the licensee planned to install temporary air purification equipment into the containment in an attempt to clean its atmosphere.

O7 Quality Assurance in Operations

O7.1 Company Nuclear Review Board (CNRB) (71707)

The inspectors observed a portion of a CNRB meeting. Critical comments about plant performance were well received by station management. Members conducted a constructive discussion of the self-assessment program. The inspectors concluded that the CNRB was an effective tool for improving licensee performance.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Licensee Event Report (LER) 50-346/98-002-00: Plant Trip Due to High Pressurizer Level As a Result of Loss of Letdown Capability. On April 10, 1998, while shutting the plant down for a refueling outage, a purification demineralizer resin retention element failed which resulted in the isolation of the reactor coolant letdown system. The loss of the letdown system caused an increase in pressurizer level and, in response, plant operators manually tripped the plant. The details of the event, the licensee's actions, and corrective actions are documented in Inspection Report (IR) 50-346/98005(DRP). This LER is closed.

O8.2 (Closed) LER 50-346/96-010-00: Control Room Emergency Ventilation System (CREVS) Not Realized as Inoperable When Rad Monitors Were Inoperable. On December 10, 1996, with one station ventilation radiation monitor out-of-service, workers removed the second station ventilation radiation monitor from service without realizing that this rendered both CREVS trains inoperable. With both CREVS trains inoperable, TS 3.0.3 applies, which requires the plant to be in hot standby within 6 hours. The two radiation monitors were simultaneously out-of-service for 87 minutes; therefore, no violation of the TS 3.0.3 action statement time requirement for shutting the plant down occurred. The licensee changed procedure DB-OP-06412, "Process and Area Radiation Monitor Procedure," to include information that the removing both radiation monitors from service rendered both trains of CREVS inoperable and the TS 3.0.3 applied in that case. This LER is closed.

O8.3 (Closed) LER 50-346/98-011-00: Manual Reactor Trip Due to Component Cooling Water System Leak. On October 14, 1998, the reactor was manually tripped due to a component cooling water system leak. The circumstances leading up to the event, the licensee's actions during the event, and the licensee's corrective actions are documented in IR 50-346/98019(DRP). The inspectors reviewed the LER and IR and determined that no new issues were identified. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance and Surveillance Activities (61726, 62707)

The following maintenance and surveillance testing activities were observed/reviewed during the inspection period:

- Anticipatory Reactor Trip System (ARTS) Interchannel Logic Test for Mode 1 conducted per DB-MI-03355

- Channel Functional Test/Calibration and Response Time of Reactor Coolant Pump Monitor (RC3601) to Steam and Feedwater System Rupture Control System Logic Channel 1 and Reactor Protection System Channel 1 conducted per DB-MI-03205

- Decay Heat Pump Quarterly Pump and Valve Test conducted per DB-SP-03136

- Emergency Diesel Generator (EDG) 1 184-Day Test conducted per DB-SC-03076

Management considered risk in scheduling maintenance activities and operators were informed of maintenance in progress. The equipment which was tested performed as designed and test personnel were knowledgeable of the systems tested. However, the inspectors noted that electrical maintenance worker communications while conducting surveillance test DB-MI-03205 were not per management expectations to use three-way communications during surveillance tests. During the test, an electrician manipulated a component before he repeated back to the procedure reader his intended action, which was essentially one-way communications. On another occasion, an electrician anticipated the next activity and started it before he was instructed to perform it. Although management expectations for communications were not effectively implemented in these cases, no procedure violation occurred. During the inspection exit meeting, maintenance management indicated that efforts were ongoing to improve maintenance personnel performance in this area.

M1.2 Jumper Use During ARTS Testing

The inspectors observed that prior to conducting surveillance test DB-MI-03355, "ARTS Interchannel Logic Test for Mode 1," which was considered by plant management to be a high risk evolution, instrumentation and controls (I&C) technicians did not verify the continuity of jumpered contacts prior to conducting this test. Additionally, the wire jumper that was used was not verified to be functional prior to use. According to the I&C technicians, the control rod drive breakers would open during the test and cause reactor trip if the contacts were not adequately jumpered. Maintenance management acknowledged that verifying adequate jumper connectivity is a good practice, and could result in avoiding an unnecessary plant transient in a case where a jumper was not adequately installed. The licensee indicated that an evaluation of ways to verify that ARTS test jumpers were properly connected would be conducted.

M1.3 Maintenance Personnel Work on Wrong Equipment

a. Inspection Scope (71707)

The inspectors reviewed the circumstances surrounding an event where electricians performed work on the wrong equipment.

b. Observations and Findings

On July 15, 1999, an electrician identified that he had worked on the wrong heat trace control cabinet. A condition report was initiated and classified as significant with a root cause evaluation required to be performed. The subsequent root cause determination identified that electricians had also worked on the wrong heat trace equipment on a second occasion. This equipment was not safety-related and is not subject to regulatory requirements. However, the inspectors were concerned with the work practices that caused the error to occur in that these work practices could cause similar problems while working on safety-related equipment.

The root cause investigation team interviewed electrical maintenance personnel, reviewed records and conducted a behavior factor analysis. The resulting report was detailed and provided a problem statement, event narrative, data analysis, experience review, root cause determination, and a comprehensive list of recommended corrective actions. The recommendations did not focus on the event itself, but focused on the behaviors that caused the event. The root causes for the event were inadequate self-checking practices by the craft and an inadequate pre-job brief between supervision and craft. Contributing factors were a lack of guidance to the craft on when and how to perform pre-job briefs, infrequent supervisory in-field observations, and STAR (Stop, Think, Act, Review) principles were not a normal part of electrical maintenance culture.

The electrical and I&C shop conducted a stand-down to: (1) emphasize the STAR principle, (2) communicate guidance to verify work on proper equipment, and (3) discuss the event and other industry events where using the STAR principle would have been beneficial. Also, electricians practiced self-verification assignments. When the second occurrence was discovered, plant staff ensured that electricians were working in the correct equipment prior to starting work. More formal corrective actions to address the underlying root causes will be developed in CR 1999-1214.

c. Conclusions

Electrical maintenance personnel worked on the wrong heat trace equipment on two separate occasions because of poor self-checking work practices. The root cause investigation was well documented and proposed corrective actions which, if implemented, should result in better overall maintenance department performance.

M1.4 Emergency Ventilation System (EVS) Charcoal Filter Replacement

a. Inspection Scope (62707)

The inspectors reviewed documentation associated with and observed a replacement of the EVS Train 1 charcoal filter.

b. Observations and Findings

The inspectors verified that tagouts were properly installed and that approved work order instructions were used at the job site. Control room operators properly tracked and complied with limiting conditions for operations. The alternate train was available and work was not allowed on its equipment while train 1 work was ongoing.

The charcoal filter consists of 54 trays filled with charcoal and ideally, each tray would be filled with charcoal from the same batch; however, charcoal from at least four different batches was used for this filter. Technical Specification Surveillance Requirement 4.6.5.1.c, required charcoal testing be performed per Regulatory Guide 1.52. Regulatory Guide 1.52 recommended that laboratory testing of charcoal absorption be performed per American National Standard Institute Standard N510-1975 which specified that representative charcoal samples be obtained for absorbent testing. The term "representative sample" was not defined in the ANSI standard. The inspectors noted that samples were not obtained from each charcoal batch during previous absorbent testing in March 1996 and January 1997; rather, a single charcoal sample was obtained for absorbent testing. The licensee indicated that the TS SR was adequately met by obtaining a single sample but that it was a good practice to obtain a sample from each charcoal batch. In addition, the licensee indicated that its normal practice was to use charcoal from the same batch and that this practice would be proceduralized.

c. Conclusions

Overall, maintenance and operations personnel effectively removed, tracked and coordinated the EVS Train 1 maintenance activity while making reasonable efforts to manage risk.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Maintenance Rule Implementation

a. Inspection Scope (62707)

The inspectors reviewed station implementation of portions of the maintenance rule.

b. Observations and Findings

Operators made reasonable determinations that systems remained functional. For example, the decay heat removal system remained functional when cooling water was secured to the decay heat removal cooler, because the cooling water could have been restored quickly by a dedicated operator. On the other hand, the EDG was determined not functional when barring the EDG, because an operator would have to perform too many operations to reliably restore the EDG in a short time.

Equipment availability times were effectively tracked by operators. Shift managers had a list of equipment that required tracking availability times. Any time equipment on the list became nonfunctional or was returned to being functional, a unit log annotation was made. The equipment out-of-service time was then translated to the daily status report. System engineers then used these numbers for tracking their system out-of-service time. These times were conservatively tracked as equipment was designated as nonfunctional when the tagout was given to an equipment operator to hang, and functional when the tagout was completely restored.

The inspectors noted that management was engaged in assuring that equipment availability times were minimized. During plan of the day meetings, system engineers presented executive summaries of plans to conduct maintenance outages on safety-significant equipment. Management displayed a questioning attitude towards minimizing equipment outage time by ensuring that appropriate maintenance and supervisory coverage was available around the clock to handle any unforeseen problems in an efficient manner.

c. Conclusions

The inspectors concluded that plant management conservatively tracked equipment out-of-service time and effectively ensured that outage times were minimized by providing the necessary resources to perform equipment maintenance and resolve emergent issues in a timely manner.

M8 Miscellaneous Maintenance Issues (92700)

M8.1 (Closed) LER 50-346/96-006-00: Reactor Coolant Pump Motor 1-2 Oil Collection System 1.5 Inch Lip Not Installed. On May 14, 1996, the licensee discovered that a 1.5 inch high lip around the top of reactor coolant pump motor (RCPM) 2-1 was not in place. This lip is part of the RCPM oil collection system and serves to direct any oil leakage from the RCPM flywheel cover and upper bearing oil level control enclosures to the oil cooler enclosure. This condition did not comply with 10 CFR 50, Appendix R fire protection requirements and was therefore outside the design basis. The licensee determined that the oil collection system was replaced during the 1993 refueling outage; however, the oil collection lip located on the top of the pump was not identified in the work package and was therefore not installed. The licensee installed the oil collection lip on May 20, 1996, and revised the maintenance procedure for the reactor coolant pumps to ensure that the oil collection system is verified to be in service after all maintenance on the pumps. The inspectors determined that the licensee's corrective actions were appropriate.

10 CFR 50, Appendix R, Section III, Paragraph O, "Oil collection system for reactor coolant pump," states, in part, that the reactor coolant pump shall be equipped with an oil collection system if the containment is not inerted during normal operation. Such collection systems shall be capable of collecting lube oil from all potential pressurized and unpressurized leakage sites in the reactor coolant pump lube oil systems. Leakage points to be protected shall include lift pump and piping, overflow lines, lube oil cooler, oil fill and drain lines and plugs, flanged connections on oil lines, and lube oil reservoirs where such features exist on the reactor coolant pumps. The Davis-Besse containment is not inerted. Contrary to this, on May 14, 1996, the RCPM was not equipped with an oil collection system capable of collecting lube oil from the RCPM flywheel cover and upper bearing oil level control enclosures. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as LER 50-346/96-006-00 **(NCV 50-346/99009-01(DRP))**.

M8.2 (Closed) LER 50-346/97-005-01: Surveillance Requirement Missed Due to Inadequate Safety Evaluation. On February 12, 1997, the licensee identified that the TS surveillance test for the vacuum leakage rate was not completed within the required frequency. This item was discussed in IR 50-346/97003(DRP) and was dispositioned as a Non-Cited Violation. The inspectors reviewed the LER and determined that the circumstances described were consistent with those previously reported. This item is closed.

M8.3 <u>(Closed) LER 50-346/98-010-01:</u> Misdiagnosis of Feedwater Control Valve Solenoid Valve Failure During Testing Results in Manual Reactor Trip. Operators manually tripped the reactor after the main feedwater control valve to Steam Generator 1 inadvertently closed during testing activities. This revision to the original LER updates corrective action efforts, such as engineering personnel troubleshooting training and initiatives to determine the solenoid valve failure mode. The original LER was closed out and discussed in Inspection Report 50-346/98017(DRP).

M8.4 <u>(Closed) LER 50-346/98-001-00 and 01:</u> Main Steam Safety Valve Setpoints Outside TS Allowable Values. On April 8, 1998, while operating at near 74 percent power, 8 of 11 main steam safety valves (MSSVs) that were tested (18 MSSVs are installed) failed to lift within the TS limits. Six of the MSSVs had a lift sitting pressure more than one percent below the TS setpoint, and two of the MSSVs had a lift setting pressure more than one percent above the TS setpoint. The safety valve lift settings were adjusted within the time allowed by the TSs, and the valves were retested satisfactorily. Engineering personnel evaluated the as-found lift data and determined that the main steam system pressure would not have exceeded previously analyzed values during anticipated over-pressure transients. During the next refueling outage, five of the valves were removed from the system and were either rebuilt or replaced. The apparent causes for the failures were: (1) the time interval between tests was too long resulting in spring relaxation, (2) main steam line vibration caused some wear of the disk to spindle connections, (3) minor galling of the seat and nozzle surfaces while a valve was in storage for an appreciable amount of time, and (4) limitations of the test method accuracy. To address the apparent causes, the licensee committed to reduce the time intervals between testing each valve from every three operating cycles to every operating cycle, and to require testing of a MSSV after installation if the MSSV was in storage for greater than two years. Other details of this item were documented in IR 50-346/98005(DRP). This LER is closed.

M8.5 <u>(Closed) LER 50-346/98-005-00:</u> Both Low Pressure Injection/Decay Heat Removal Pumps Inoperable During Test. On June 1, 1998, at 98 percent power, an operator inadvertently closed the train 1 low pressure injection (LPI) system pump suction valve instead of the train 2 LPI system pump suction valve during train 2 testing activities. This caused both LPI system trains to become inoperable, because the fuses to LPI system train 2 pump were removed. The operator immediately recognized the error and re-opened the injection valve. Both trains were inoperable for only 33 seconds, therefore, no TS action statement violations occurred. The licensee determined that the root cause was personnel error by not doing an adequate self-check. Corrective actions conducted were individual training and lessons learned training for the operations department. The inspectors determined that the corrective actions were appropriate. This item was discussed in IR 50-346/98009 (DRP) and was dispositioned as a minor violation.

M8.6 <u>(Closed) LER 50-346/98-012-00 and 01 and Inspection Followup Item (IFI) 50-346/98017-01(DRP):</u> Reactor Trip Due to ARTS Signal While Removing ARTS Channel One From Bypass. On October 18, during reactor restart activities, an automatic reactor trip occurred from four percent power due to an inadvertent ARTS actuation. The cause of the trip was non-installed wires on the spare position of all four ARTS Test Trip Bypass Switches, coincident with an operator that inadvertently positioned the test switch to the spare position, contrary to procedural directions. Corrective actions to prevent recurrence were to change ARTS procedures to preclude the condition from recurring, and to install the missing ARTS wiring prior to startup from the 12th refueling outage. Other details of the event were documented in IR 50-346/98017(DRP).

Criterion V to Appendix B to 10 CFR 50, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Procedure DB-OP-06901, "Plant Startup," is used during reactor startups, an activity affecting quality. Step 3.21 of Procedure DB-OP-06901 required an operator to position the ARTS channel 1 test trip bypass switch to the operate position. Contrary to this, on October 18, 1998, while performing step 3.21 of Procedure DB-OP-06901, an operator positioned the ARTS bypass switch to the spare position instead of the operate position. This action, in conjunction with a degraded wiring condition in the ARTS cabinet, caused a trip of the reactor. The failure to position the switch in accordance with this procedure was a violation. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as LER 50-346/98-012 **(NCV 50-346/99009-02(DRP))**.

III. Engineering

E1 Conduct of Engineering

E1.1 Evaluation of an EDG Degraded Condition (37551)

During a test of EDG 1, the inspector was concerned that a small hydraulic leak on the governor system would require frequent hydraulic oil additions to the governor during an extended EDG run and be a burden to operators. The EDG system engineer generated a CR that determined that the EDG would continue to run for greater than four days before hydraulic oil would need to be added. Additionally, frequent operator log readings of the governor hydraulic oil sight glass would provide early indication of lower than desired levels. The inspector concluded that the system engineer conservatively documented and dispositioned the inspectors' question pertaining to the EDG 1 governor hydraulic oil leak.

E2 Engineering Support of Facilities and Equipment

E2.1 Update to Station Integrated Plant Examination (IPE) Results in Efforts Decrease in Core Damage Frequency (37551)

The startup feed pump is not credited in the USAR for accident mitigation functions and has no TS requirements associated with it. Since the installation of the motor-driven feed pump, the startup feed pump had not been used or maintained. However, during the recent update to the IPE, station engineering personnel determined that the startup feedwater pump would provide a substantial benefit to mitigate the consequences of a loss of feedwater accident. Therefore, management added the pump to the maintenance rule program and started to perform maintenance on the pump to ensure its functionality. The inspectors concluded that station management exhibited a commitment to nuclear safety, when they took measures to ensure the startup feedwater pump would be available for accident mitigation functions, even though no regulatory requirement existed to do so.

E8 Miscellaneous Engineering Issues (92700, 2515/141)

E8.1 (Closed) LER 50-346/97-012-01: Decay Heat Cooler Seismic Design Inadequacy. On September 4, 1997, the licensee identified that the decay heat coolers were not seismically qualified. This LER revision updated the completion time for evaluating whether nozzle loads were properly addressed for other tanks and heat exchangers. The original LER was closed and dispositioned as a Non-Cited Violation in IR 50-346/99008(DRP).

E8.2 (Closed) LER 50-346/98-013-00 and 01: Safety Valve Rupture Disks May Induce Excessive Eccentric Loading of Pressurizer Vessel Nozzles. On November 5, 1998, the licensee determined that eccentric loading of pressurizer safety valve nozzle piping could occur if one of the two rupture disks on the safety valve discharge tees remained intact during a safety valve lift. The licensee removed the rupture disks as a precautionary measure. A modification of the system was completed to eliminate the two rupture disks and install a single disk configuration that ensured even loading on the nozzle piping. The licensee determined that the error occurred in 1987 when erroneous assumptions were used to raise the rupture set point. The licensee evaluated its current modification process and determined that similar errors would not occur. The licensee initially determined that the system was not able to meet its design function. Further analysis using the actual relief capacity of the pressurizer safety valves determined both rupture disks would burst for all safety valve lift scenarios at all expected safety valve lift settings and therefore, there was no potential to induce excessive eccentric loads existed. Therefore, the licensee retracted the event on June 23, 1999. This item is closed.

E8.3 Review of Year 2000 (Y2K) Readiness of Computer Systems (2515/141)

The inspectors reviewed the licensee's closeout of a Y2K readiness open item pertaining to the maintenance management system for surveillance tracking (MMST). The inspectors reviewed documentation that certified that the MMST would function properly and questioned plant personnel who participated in the test activities to verify that the MMST was Y2K ready. The MMST was modified by FirstEnergy corporate personnel and tested to ensure it would function during Y2K sensitive dates. This involved running the modified system on a test platform, rolling the dates to the sensitive dates, and systematically verifying that the MMST continued to function as expected. Additionally, in the event that communications between FirstEnergy computers and Davis-Besse were disrupted, compensatory measures to print out an extended surveillance schedule prior to December 31 were planned.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Dose Reduction Efforts (71750)

The inspectors reviewed the licensee's efforts to reduce the dose rates from equipment associated with decay heat removal (DHR) system train 1. Portions of the DHR system that had relatively high radiation levels were flushed during a normally scheduled quarterly pump test. A one-time evolution procedure was generated to accomplish the task, since the test procedure did not provide for the additional steps required to flush these portions of the system. Execution of the flush plan extended the time to perform the surveillance test by about two hours. Radiation doses were reduced on some hot spots by a factor of four. A previous flush on DHR train 2 reduced hot spot radiation levels more dramatically (up to a factor of 500 decrease in hot spot activity). The inspectors concluded that the licensee effectively reduced the dose rates associated with decay heat removal system train 1.

R8 Miscellaneous RP&C Issues (92700)

R8.1 (Closed) LER 50-346/99-002-00: Both Trains of EVS Rendered Inoperable Due to Unattended Open Door. On February 8, 1999, the licensee discovered a shield building airtight door was open which rendered both trains of EVS inoperable. The door was immediately closed. A subsequent investigation identified that the door had been left open for about 18 minutes by a radiation protection technician. Due to the short duration of the condition, no violation of TS action requirements occurred. Additionally, although the EVS would not have been able to draw down the vacuum in the negative pressure boundary to values assumed in the accident analysis, the EVS would have still functioned to filter out postulated accident fission products that could leak from the containment vessel. The licensee conducted training with all radiation protection personnel to provide awareness of the requirement to maintain boundary doors in the proper positions.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on August 2, 1999. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X3 Management Meeting Summary

On July 30, 1999, the NRC Region III Administrator toured the plant and met with licensee management individuals. Topics discussed included the licensee's corrective action program, and its actions to improve work management processes and human performance at the station.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. C. Beier, Manager, Quality Assessment
W. J. Bentley, Work Control Support
G. G. Campbell, Vice President Nuclear
R. B. Coad, Jr., Superintendent, Radiation Protection
R. M. Cook, Licensing, Engineer
R. E. Donnellon, Director, Engineering and Services
D. L. Eshelman, Manager, Operations
J. L. Freels, Manager, Regulatory Affairs
S. Garchow, Training Manager
P. R. Hess, Manager, Supply
D. M. Imlay, Superintendent, Operations
D. F. Isherwood, Supervisor, Documentation Management
J. H. Lash, General Manager, Plant Operations
D. H. Lockwood, Supervisor, Compliance
J. L. Michaelis, Manager, Maintenance
S. P. Moffitt, Director, Nuclear Support Services
S. A. Nankervis, Student, Compliance
J. E. Reddington, Superintendent, Mechanical Services
M. J. Roder, Superintendent, E/C
J. W. Rogers, Manager, Plant Engineering
G. A. Skeel, Manager, Security
H. W. Stevens, Jr., Manager, Nuclear Safety & Inspections
F. L. Swanger, Manager, Design Basis Engineering

NRC

K. S. Zellers, Resident Inspector, Davis-Besse

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
2515/141	Review of Year 2000 (Y2K) Readiness of Computer Systems

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-346/99009-01	NCV	inadequate reactor coolant pump oil collection system
50-346-99009-02	NCV	operator procedure error contributes to reactor trip

Closed

50-346/98-002-00	LER	plant trip due to high pressurizer level as a result of loss of letdown capability
50-346/96-010-00	LER	CREVS not realized as inoperable when rad monitors were inoperable
50-346/98-011-00	LER	manual reactor trip due to component cooling water system leak
50-346/96-006-00	LER	reactor coolant pump motor 2-1 oil collection system 1.5 inch lip not installed
50-346/97-005-01	LER	surveillance requirement missed due to inadequate safety evaluation
50-346/98-010-01	LER	misdiagnosis of feedwater control valve solenoid valve failure during testing results in manual reactor trip
50-346/98-001-00; 50-346/98-001-01	LER	main steam safety valve setpoints outside TS allowable values
50-346/98-005-00	LER	both low pressure injection/decay heat removal pumps inoperable during test
50-346/98-012-00; 50-346/98-012-01	LER	reactor trip due to ARTS signal while removing ARTS channel one from bypass
50-346/98017-01	IFI	automatic reactor trip during plant restart
50-346/97-012-01	LER	decay heat cooler seismic design inadequacy
50-346/98-013-00; 50-346/98-013-01	LER	safety valve rupture disks may induce excessive eccentric loading of pressurizer vessel nozzles
50-346/99-002-00	LER	both trains of EVS rendered inoperable due to unattended open door
50-346/99009-01	NCV	inadequate reactor coolant pump oil collection system
50-346/99009-02	NCV	operator procedure error contributes to reactor trip

Discussed

None

LIST OF ACRONYMS USED

ARTS	Anticipatory Reactor Trip System
CFR	Code of Federal Regulations
CNRB	Company Nuclear Review Board
CR	Condition Report
CREV	Control Room Emergency Ventilation
DHR	Decay Heat Removal
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
EVS	Emergency Ventilation System
I&C	Instrumentation and Controls
IFI	Inspection Followup Item
IPE	Integrated Plant Examination
IR	Inspection Report
LER	Licensee Event Report
LPI	Low Pressure Injection
MMST	Maintenance Management System Tracking
MSSV	Main Steam Safety Valves
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
RCS	Reactor Coolant System
RP	Radiation Protection
RWP	Radiation Work Permit
TS	Technical Specification
USAR	Updated Safety Analysis Report
VIO	Violation

Reference S

December 11, 2001

Mr. Guy G. Campbell
Vice President - Nuclear
FirstEnergy Nuclear Operating Company
Davis-Besse Nuclear Power Station
5501 North State Route 2
Oak Harbor, OH 43449-9760

SUBJECT: DAVIS-BESSE NUCLEAR POWER STATION
NRC INSPECTION REPORT 50-346/01-13

Dear Mr. Campbell:

On November 13, 2001 the NRC completed an inspection at your Davis-Besse Nuclear Power Station. The enclosed report documents the inspection findings which were discussed on November 13, 2001, with you and other members of your staff.

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

Based on the results of this inspection, the inspectors identified one issue of very low safety significance (Green) that was determined to involve a violation of NRC requirements. However, because of its very low safety significance and because it was entered into your corrective action program, the NRC is treating this issue as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC' s Enforcement Policy. If you deny this Non-Cited Violation, you should provide a response with a basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Davis-Besse Nuclear Power Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

Original signed by
Christine A. Lipa

Christine A. Lipa, Chief
Branch 4
Division of Reactor Projects

Docket No. 50-346
License No. NPF-3

Enclosure: Inspection Report 50-346/01-13

cc w/encl: B. Saunders, President - FENOC
Plant Manager
Manager - Regulatory Affairs
M. O'Reilly, FirstEnergy
Ohio State Liaison Officer
R. Owen, Ohio Department of Health
A. Schriber, Chairman, Ohio Public Utilities Commission

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No: License No:	50-346 NPF-3
Report No:	50-346/01-13(DRP)
Licensee:	FirstEnergy Nuclear Operating Company
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 North State Route 2 Oak Harbor, OH 43449-9760
Dates:	October 1 through November 13, 2001
Inspectors:	D. Simpkins, Acting Senior Resident Inspector K. Green-Bates, Engineering Specialist J. House, Ph.D., Senior Engineering Specialist
Approved by:	Christine A. Lipa, Chief Branch 4 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000346-01-13, on 10/01-11/13/2001, FirstEnergy Nuclear Operating Company, Davis-Besse Nuclear Power Station; maintenance risk assessment and emergent work evaluation.

This report covers a 6-week routine inspection conducted by resident and regional inspectors. One Green finding was identified which was the subject of a Non-Cited Violation. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609 "Significance Determination Process" (SDP). The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

Green. The licensee failed to have procedures appropriate to the circumstances to identify and control the removal of external flood barriers. As a result, the external flood barriers to the service water intake structure were removed, providing a pathway which could have rendered the safety-related service water pumps inoperable in the event of a design basis external flooding event. One Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified.

The issue was of very low safety significance due to the very low initiating event frequency and due to high probability of recovery for flood barriers, given the nature of the initiating event. (Section 1R13)

B. Licensee Identified Findings

No findings of significance were identified.

Report Details

Summary of Plant Status

The plant operated at 100 percent power throughout most of the inspection period. Exceptions were for brief power reductions to about 93 percent for turbine testing, to 90 percent at the request of the system dispatcher, and one reduction to about 10 percent power for main turbine generator stator cooling water system maintenance.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed the design features and implementation of the licensee's procedures designed to protect mitigation systems from adverse weather effects. The review included a procedural evaluation for cold weather preparations and contingencies, system walkdowns to ensure adequate equipment protection to preclude weather-initiated events and an evaluation of pre-emptive compensatory actions for adverse weather mitigation.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial System Walkdown (71111.04Q)

a. Inspection Scope

The inspectors selected a redundant or backup system to an out-of-service or degraded train, reviewed documents to determine correct system lineup, and verified critical portions of the system configuration. Instrumentation valve configurations and appropriate meter indications were also observed. The inspectors observed various support system parameters to determine the operational status of the system. Control room switch positions for the systems were observed. Other conditions, such as adequacy of housekeeping, the absence of ignition sources, and proper labeling were also evaluated. The inspectors conducted partial walk-down inspections of risk significant equipment by comparing station configuration control documentation with actual system/train lineups for:

- Risk-significant electrical components during switchyard circuit breaker ACB34560 outage

- #1 Emergency Diesel Generator (EDG) during a #2 EDG outage

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown (71111.04S)

a. Inspection Scope

Additionally, the inspectors conducted a complete walkdown for the Component Cooling Water (CCW) System. The inspectors verified mechanical and electrical equipment lineups, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and ensured ancillary equipment or debris did not interfere with equipment operation.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

The inspectors reviewed the licensee's operator training program to evaluate operator performance in mitigating the consequences of a simulated event. The inspectors observed operator performance during a simulator training scenario for miscellaneous plant equipment failures (Steam Generator Startup Level indicator failed low, Turbine Generator lube oil leak, Reactor Trip, B Bus de-energizes, Loss of Gland Seal, Auxiliary Feedwater initiation). The inspectors evaluated the following attributes of the activities:

- Communication clarity and formality
- Timeliness and appropriateness of crew actions
- Prioritization, interpretation, and verification of alarms
- Correct use and implementation of procedures
- Oversight and direction provided by the shift manager and control room supervisor

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12Q)

a. Inspection Scope

The inspectors reviewed equipment issues, surveillance test failures, and other performance problems for the Component Cooling Water system. The inspectors reviewed whether the components were properly scoped in accordance with the

Maintenance Rule, whether failures were properly characterized, and whether the performance criteria were appropriate. In addition, the inspectors reviewed condition reports associated with implementation of the maintenance rule to determine if the licensee was identifying problems and entering them in the corrective action program.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors evaluated the effectiveness of the risk assessments performed before maintenance was conducted on structures, systems and components and verified how risk was managed and if maintenance risk assessments and emergent work problems were adequately identified and resolved for the following activities:

- Severe weather with the #2 Emergency Diesel Generator and #3 Service Water Pump unavailable because of maintenance

- Auxiliary Feedwater Steam Generator Level Controller troubleshooting

- Service Water Pump #3 and Cooling Tower Makeup Pump #2 removed from the Intake Structure Service Water Pump room

b. Findings

Green. One finding of very low safety significance (Green), a Non-Cited Violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for the failure to have procedures appropriate to the circumstances to identify and control the removal of external flood barriers, an activity affecting quality.

When installed, the Cooling Tower Makeup Pumps and Service Water Pumps provide a flooding barrier for the service water intake structure in the event of a design basis external flooding event. However, the #2 Cooling Tower Makeup Pump and the #3 Service Water Pump were removed from the intake structure on July 25, 2001, and October 16, 2001, respectively, for refurbishment. The inspectors identified that the temporary covers placed over the resultant floor openings where the pumps were removed were insufficient to provide an effective barrier against water ingress and act as a flood barrier in the event of a design basis external flood.

In the event of a design basis external flood, Davis-Besse Updated Safety Analysis Report (USAR) Section 2.4.2.2 postulates a maximum probable high water level (584 feet International Great Lakes Datum (IGLD)) in excess of the floor elevation (576 feet IGLD) of the Service Water Pump room. Safety related equipment in the structure which would be adversely affected by the flood and rendered inoperable include the #1 and #2 Service Water Pumps and Strainers and the Diesel Fire Pump (DFP), with associated breakers and valves.

Because these barriers were removed without compensatory actions, potentially affecting the safety-related Service Water system and the DFP, the inspectors concluded this issue had a credible impact on safety. Because the issue potentially impacted the operability of these systems during an external flooding event, the SDP was entered for mitigating systems. Upon conducting the Phase 1 SDP, the inspectors concluded that the finding was potentially risk significant in that it involved an external flooding scenario whereby the function of both trains of Service Water and/or the DFP could be affected.

The licensee performed a risk evaluation of the finding and identified the likelihood of core damage from failing to seal the intake structure, or protect the DFP during an external flood, was low, and not significant in terms of overall risk to the public. The evaluation was based on: the very low probability of the type of flooding event in question; the probability all Service Water would be lost; the probability that the licensee would be unsuccessful in installing temporary barriers around vital equipment; the probability that the licensee would be unsuccessful in arranging alternative cooling options; and the availability of long-term core cooling from alternate sources.

The licensee's review of this issue indicated that the frequency of an external flooding event with a sufficient magnitude to flood the Service Water Intake Structure was very low, primarily due to the very low initiating event (IE) frequency but also due to the high probability of recovery for flood barriers, given the nature of the IE. The inspectors and the Region III Senior Risk Analyst (SRA) performed a phase 3 SDP analysis by reviewing the licensee's IPEEE, and the licensee's evaluation for this specific condition. The inspectors and SRA concluded that the finding was of very low risk significance (Green).

Upon review of the licensee's Work Order development process, no procedural guidance was provided to specifically identify the hazards of removing an external flooding barrier. The failure to have adequate procedures to identify and control the removal of external flood barriers is considered a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" (NCV 50-346/01-13-01(DRP)). This violation is associated with an inspection finding that is characterized by the SDP process as having very low risk significance (i.e. Green) and is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 01-2928.

1R14 Performance in Non-Routine Evolutions (71111.14)

a. Inspection Scope

The inspectors reviewed station personnel preparations and operator performance for a reactor down-power to about 10 percent for corrective maintenance on the main turbine generator stator cooling water system. This review was to determine if personnel actions were appropriate to the evolution and in accordance with procedures and training.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following operability determinations and evaluations affecting mitigating systems to determine whether operability was properly justified and the component or system remained available, such that no unrecognized risk increase had occurred.

- Operability Justification 2001-0001, Removal of One ECCS Room Cooler From Service
- Operability Justification 2001-0012, Removal of One ECCS Room Cooler From Service
- Operability Justification 2001-0013, EDG 1-1, DA30 Air Start Side
- Operability Justification 2001-0022, EDG 1-2, DA45 Air Start Side

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors verified that the post-maintenance test procedures and test activities were adequate to verify system operability and functional capability for the following risk significant activities:

- Reactor Coolant System Average Temperature input module repair and replacement in the Integrated Control System
- Emergency Diesel Generator 184 Day Test
- Auxiliary Feedwater #2 Steam Generator Level Controller and Emergency Diesel Generator #2 Sequencer repair and replacement

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary modifications to verify they did not affect the safety functions of important safety systems. The inspectors reviewed the temporary modifications and the associated 10 CFR 50.59 screenings against the system design basis documentation, including the USAR and TSs to determine if there was any effect on system operability or availability and to verify temporary modification consistency with plant documentation and procedures:

- Bypassing the charcoal filters on Radiation Elements RE 4597AB/BA
- Service Water Intake Structure flooding barriers

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit (RWP) Reviews

a. Inspection Scope

The inspector reviewed the radiological conditions of work areas within radiation areas and high radiation areas (HRAs) in the radiologically restricted area to verify the adequacy of radiological boundaries and postings. This included walkdowns of several high and locked high radiation area boundaries in the Auxiliary and Radwaste Buildings. The inspector performed independent measurements of area radiation levels and reviewed associated licensee controls to determine if the controls (i.e., surveys, postings, and barricades) were adequate to meet the requirements of 10 CFR Part 20 and the licensee's Technical Specifications (TSs). Radiation work permits for jobs having significant radiological dose potential were reviewed for protective clothing requirements and dosimetry requirements including alarm set points.

b. Findings

No findings of significance were identified.

.2 Job In-Progress Reviews

a. Inspection Scope

The inspector observed aspects of work activities that were being performed in areas having significant dose potential in order to ensure that adequate radiological controls were assigned and implemented. The inspector observed radiation protection preparations and radiological controls for the spent fuel pool rerack job. In addition, a spent fuel pool filter change-out was observed. The inspector reviewed engineering controls, radiological postings, radiological boundary controls, radiation work permit requirements, radiation monitoring locations and attended pre-job briefings to verify that radiological controls were effective in minimizing dose. The inspector also observed radiation worker performance to verify that the workers were complying with radiological requirements and were demonstrating adequate radiological work practices. During work evolutions, radiation protection technician performance was observed to verify that the technicians were aware of the job requirements and that their performance was consistent with the actual and potential radiological hazards involved.

b. Findings

No findings of significance were identified.

.3 High Dose Rate, High Radiation Area and Very High Radiation Area Controls

a. Inspection Scope

The inspector reviewed the licensee's controls for high dose rate HRAs and very high radiation areas (VHRA) including the licensee's procedure for posting and control of these areas to verify the licensee's compliance with 10 CFR Part 20 and the site's TSs. The inspector also reviewed records of HRA/VHRA boundary and posting surveillances and performed a walk down to verify their adequacy. In addition, the inspector reviewed the licensee's controls for high dose rate material that was stored in the spent fuel pool and the licensee's inventory of materials currently stored in the spent fuel pool to verify that the licensee implemented adequate measures to prevent inadvertent personnel exposures from these materials.

b. Findings

No findings of significance were identified.

.4 Problem Identification and Resolution

a. Inspection Scope

The inspector reviewed the licensee's condition report (CR) database from January 2001 through October 2001 concerning problems in HRAs, radiation worker performance, and radiation protection technician performance. The inspector reviewed these documents to assess the licensee's ability to identify repetitive problems, contributing causes, the extent of conditions, and corrective actions which will achieve lasting results.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

.1 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspector reviewed jobs being performed in areas of potentially elevated dose rates and examined the work sites in order to evaluate the licensee's use of ALARA controls to minimize radiological exposure. Job exposure estimates were reviewed and work areas were surveyed to determine radiological conditions. The ALARA briefing documentation, the use of engineering controls and shielding were evaluated for dose minimization effectiveness. During job site walkdowns, radiation workers and supervisors were observed to determine if low dose waiting areas were being used appropriately, and equipment staging, availability of tools and work crew size were evaluated to determine the effectiveness of job supervision in dose minimization.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspector reviewed audits, self-assessments and CRs related to the ALARA program including post outage reviews of higher dose jobs to determine if problems were identified and properly characterized, prioritized and entered into the corrective action program. The most dose intensive jobs were reviewed to determine if radiological work problems/deficiencies had been identified, adequate safety evaluations performed, and the problems entered into the licensee's corrective action system.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

.1 Source Tests and Calibration of Radiological Instrumentation

a. Inspection Scope

The inspector evaluated radiological instrumentation associated with monitoring transient high and/or very high radiation areas, and instruments used for remote emergency assessment to verify that the calibration process was conducted consistent with industry standards and in accordance with station procedures. The inspector reviewed the Updated Final Safety Analysis Report, performed walkdowns and reviewed calibration records to confirm that selected area radiation monitors (ARMs) were operable and properly indicated area radiation levels. The inspector examined the licensee's alarm set points for selected ARMs to verify that the set points were established consistent with the station's requirements. The inspector reviewed the most recent calibration records for selected ARMs and continuous air monitors (CAMs) which included, but were not limited to, the following:

Containment Vessel Monitors
Mechanical Penetration Rooms Monitors
Containment Air Monitors
Spent Fuel Pool Area Monitors
ECCS Room Monitor

The inspector reviewed CY 2000 - 2001 calibration records and procedures for those instruments utilized for surveys of personnel and equipment prior to egress from the radiologically restricted area. The inspector examined, and observed RP staff complete functional tests of, selected personnel contamination monitors, portal monitors, and a small article monitor to verify that these instruments were source checked and calibrated adequately, consistent with station procedures and industry standards.

The inspector examined portable survey instruments maintained in the licensee's instrument issue area to verify that those instruments designated "ready for use" had current calibrations, were operable, and were in good physical condition. The inspector observed radiation protection staff source check portable radiation survey instruments to verify that those source checks were adequately completed using appropriate radiation sources and station procedures. The inspector reviewed the calibration procedures and selected 2001 calibration records to verify that the portable radiation survey instruments had been properly calibrated consistent with the licensee's procedures.

Additionally, the inspector performed a walk down of the post accident sampling system and reviewed quality control records to ensure that the system was capable of obtaining representative samples of reactor coolant and containment atmosphere.

b. Findings

No findings of significance were identified.

.2 Self-Contained Breathing Apparatus (SCBA) Program

a. Inspection Scope

The inspector reviewed aspects of the licensee's respiratory protection program for compliance with the requirements of Subpart H of 10 CFR Part 20, to ensure that self-contained breathing apparatus (SCBA) were properly maintained and stored, and to ensure that appropriate personnel were required to be SCBA qualified. The inspector performed walkdowns of selected SCBA storage locations and inspected a sample of the units to assess the material condition of the equipment and to verify that the monthly inspection requirement had been met. In addition, the inspector reviewed the licensee's current training and qualification records to verify that applicable personnel were currently trained and qualified for SCBA use, as required by the Emergency Plan and plant procedures.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspector reviewed CRs for 2001 along with self assessments and surveillances that addressed radiation instrument/SCBA deficiencies to determine if any significant radiological incidents involving radiation instrument deficiencies had occurred since the last assessment. Additionally, the inspector examined these documents to verify the licensee's ability to identify repetitive problems, contributing causes, the extent of conditions, and implement corrective actions to achieve lasting results.

b. Findings

No findings of significance were identified.

2PS2 Radioactive Material Processing and Transportation (71122.02)

.1 Shipping Records

a. Inspection Scope

The inspector reviewed five non-excepted package shipment manifests completed in 2001, to verify compliance with NRC and Department of Transportation requirements (i.e., 10 CFR Parts 20 and 71 and 49 CFR Parts 172 and 173).

b. Findings

No findings of significance were identified.

.2 Identification and Resolution of Problems

a. Inspection Scope

The inspector reviewed a self-assessment of the radioactive waste management and shipping programs to evaluate the effectiveness of the self-assessment process to identify, characterize, and prioritize problems. The inspector also reviewed year 2001 CRs that addressed the radioactive waste management and shipping program deficiencies, to verify that the licensee had effectively implemented the corrective action program.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors reviewed Licensee Event Reports and unit log entries to determine if the performance indicators for scrams and scrams with loss of normal heat removal were accurately and completely reported to the NRC by the licensee. The previous 12 months of data were inspected.

The inspector reviewed the licensee's determination of performance indicators for the occupational and public radiation safety cornerstones to verify that the licensee accurately determined these performance indicators and had identified all occurrences required. These indicators included the Occupational Exposure Control Effectiveness and the Radiological Effluent TSs/Offsite Dose Calculation Manual Radiological Effluent Occurrences. The inspector reviewed CRs for the year 2001, quarterly offsite dose calculations for radiological effluents for year 2001 and access control transactions for January 2001 through September 2001. During plant walkdowns (Section 2OS1.1), the inspector also verified the adequacy of posting and controls for locked HRAs, which contributed to the Occupational Exposure Control Effectiveness performance indicator.

The inspector also reviewed the licensee's reactor coolant system activity performance indicator for the reactor safety cornerstone to verify that the information reported by the licensee was accurate. The inspector reviewed the licensee's reactor coolant sample results for maximum dose equivalent iodine-131, January through September 2001, and the licensee's sampling and analysis procedures. The inspector also observed a chemistry technician obtain and analyze a reactor coolant sample.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

.1 The inspectors presented the inspection results to Mr. Campbell and other members of licensee management at the conclusion of the inspections on November 13, 2001. The licensee acknowledged the findings presented. No proprietary information was identified.

.2 Interim Exit Meeting

Senior Official at Exit:	Mr. Howard Bergendahl, Plant Manager
Date:	November 8, 2001
Proprietary:	No
Subject:	Access Control, ALARA, Instrumentation, and Transportation
Change to Inspection Findings:	No

KEY POINTS OF CONTACT

Licensee
G. Campbell, Site Vice President
H. Bergendahl, Plant Manager
S. Coakley, Outage Manager
D. Eschelman, Manager, Plant Engineering
B. Geddes, Chemistry Supervisor
R. Greenwood, Health Physics Services Supervisor
J. Michaelis, Manager, Supply Chain
D. Miller, Supervisor, Compliance
W. Mugge, Manager, Nuclear Training
R. Pell, Manager, Operations
P. Shultz, Radiation Protection Manager
H. Stevens, Manager, QA
L. Worley, Director, Support Services

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-346-01-013-01	NCV	Failure to Have Adequate Procedures to Identify and Control the Removal of External Flood Barriers

Closed

50-346-01-013-01	NCV	Failure to Have Adequate Procedures to Identify and Control the Removal of External Flood Barriers

Discussed

None.

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
AFW	Auxiliary Feedwater
ALARA	As Low As Is Reasonably Achievable
ARM	Area Radiation Monitor
CAM	Continuous Air Monitor
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CR	Condition Report
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
HRA	High Radiation Area
IGLD	International Great Lakes Datum
MWO	Maintenance Work Order
NRC	Nuclear Regulatory Commission
OA	Other Activities
OS	Operations Schematic
P&ID	Piping and Instrumentation Drawing
PARS	Publicly Available Records
SCBA	Self Contained Breathing Apparatus
SD	System Description
SDP	Significance Determination Process
TM	Temporary Modification
TS	Technical Specifications
USAR	Updated Safety Analysis Report
VHRA	Very High Radiation Area

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather Protection

DB-OP-06913	Seasonal Plant Preparation Checklist	Rev. 3
RA-EP-02810	Tornado	Rev. 1
DB-ME-09521	Preventative Maintenance and Circuit Testing of Freeze Protection and Heat Tracing	Rev. 1
DB-OP-06331	Freeze Protection and Electrical Heat Trace	Rev. 3

1R04 Equipment Alignments

CR 00-4082	#1 CCW Pump Snubber	12/29/00
CR 01-0188	Potential Unavailability of CCW Pump due to Lack of Breaker Testing	1/22/01
CR 01-0626	Procedure Deficiency in DB-OP-02005 CCW Malfunctions	3/3/01
CR 01-0627	Discrepancy Between OS-21 (CCW) and DB-OP-02005	3/3/01
CR 01-0822	CCW Pump 2 Discharge Check Valve	3/22/01
CR 01-1623	Condition Monitoring of Heat Exchangers Cooled by CCW	7/2/01
CR 01-1629	CCW Heat Exchanger Test Procedures Do Not Incorporate	8/21/01
CR 01-2334	Spend Fuel Pool Heat Exchanger CCW Isolation Valves Not Providing Isolation for Maintenance	10/25/01
DB-OP-01000	Operation of Station Breakers	3/30/01
C01-0086	Component Cooling Water System Procedure	7/11/01
CR 01-2695	Flange Fasteners without the Required Full Nut Thread Engagement (NRC ID)	10/10/01
DB-MM-09266	Flange Torquing	7/18/01
OS-41A	Emergency Diesel Generator Systems, Sh. 1	Rev. 18
OS-41A	Emergency Diesel Generator Systems, Sh. 2	Rev. 15
OS-41B	Emergency Diesel Generator Air Start/Engine Start System	Rev. 19
OS-41E	Station Blackout Diesel Generator Air Start/Engine Start System	Rev. 8

OS-41F	Station Blackout Diesel Generator Electrical Controls and Fuel Oil Systems	Rev. 1

1R11 Licensed Operator Requalification

Simulator Guide Number ORQ-SIM-S173	OTSG SU LVL fail low, TG lube oil leak, Reactor Trip, B Bus de-energizes, Loss of Gland Seal, AFW PU	8/30/01
DB-OP-2000	Specific Rule#4	
DB-OP-2000	Specific Rule#6	
DB-OP-00000	Conduct of Operations	Rev. 4

1R12 Maintenance Rule Implementation

CR 00-4082	#1 CCW Pump Snubber	12/29/00
CR 01-0188	Potential Unavailability of CCW Pump due to Lack of Breaker Testing	1/22/01
CR 01-0626	Procedure Deficiency in DB-OP-02005 CCW Malfunctions	3/3/01
CR 01-0627	Discrepancy Between OS-21 (CCW) and DB-OP-02005	3/3/01
CR 01-0822	CCW Pump 2 Discharge Check Valve	3/22/01
CR 01-1623	Condition Monitoring of Heat Exchangers Cooled by CCW	7/2/01
CR 01-1629	CCW Heat Exchanger Test Procedures Do Not Incorporate	8/21/01
CR 01-2334	Spend Fuel Pool Heat Exchanger CCW Isolation Valves Not Providing	10/25/01
DB-OP-01000	Operation of Station Breakers	3/30/01

1R13 Maintenance Risk Assessment and Emergent Work Evaluation

	Maintenance Risk Profile for the Week of 10/22/01	
CR 01-2868	Scheduled Work Not Completed Due to Weather Conditions	10/26/01
CR 01-2628	Inability of SG Level Control to Shift to High Level Setpoint	10/5/01
CR 01-2666	Re-evaluation of Auto SG Level Control System Operability	10/9/01
	Maintenance Risk Profile for the Week of 10/8/01	
OJ 2001-0024	External Flooding Evaluation of the Service Water Pump Room	11/1/01

OJ 2001-0026	Temporary Covers to Provide Flood Protection	11/2/01
Barrier 052-F/EXT	Review of Regulatory Issue Summary 2001-09 Applicability to MWO 01-004802-000 and MWO 99-005015-000	
C-1594	Barrier Functional List	Rev. 2
USAR 2.4.2.2	Lake Flooding	Rev. 21
USAR 2.4.2.1	Flood History	Rev. 22
	Standing Order 01-002, Rev. 4 NRC Issue Summary 2001-009, Control of Hazard Barriers	8/8/01
CR 01-2910	Maintenance Deficiencies Found By NRC Inspector	10/31/01
CR 01-2928	Intake Structure Flooding Issue With Pumps Removed	11/1/01
CR 01-1954	Intake Structure Missile Shield	7/31/01
TM 01-0020	Installation of a Temporary Barrier in place of #3 Service Water Pump	11/2/01
TM 01-0021	Installation of a Temporary Barrier in place of #2 Cooling Tower Makeup Pump	11/2/01
NOP-WM-1001	Work Order Planning Process	Rev. 0
DB-DP-00007	Control of Work	Rev. 3
DB-DP-00007	Control of Work	Rev. 2
NOP-WM-4002	Repair Identification and Toolpouch Maintenance	Rev. 0
DB-PF-00002	Preventative Maintenance Program	Rev. 1
DB-MN-00001	Conduct of Maintenance	Rev. 7
WPG-1	Administrative Work Process Guidelines Manual	Rev. 13
C-NSA-99-16.47	Core Damage Frequency due to Flooding of the Service Water Pump Room	Rev. 0
NG-DB-0001	Risk Significant Component Matrix Safety Monitor	Rev. 0

<u>1R14 Performance in Non-Routine Evolutions</u>

DB-OP-00000	Conduct of Operations	Rev. 4

1R15 Operability Evaluations

OJ 2001-0012	Removal of One ECCS Room Cooler From Service	5/14/01
OJ 2001-0001	Removal of One ECCS Room Cooler From Service	1/3/01
CR 01-0013	Operability Justification for ECCS Room Cooler #1 (E42-1)	1/3/01
PCR 00-2141	Procedure Change Request 00-2141	11/28/00
CR 01-2440	ECCS Room Cooler #4	10/19/01
OJ 2001-0013	EDG 1-1, DA30 Air Start Side	7/26/01
OJ 2001-0022	EDG 1-2, DA45 Air Start Side	10/12/01
CR 01-2717	DA62 did not Reset Properly Upon Idle Start of EDG2	10/12/01
NG-DB-0018	Operability Determinations Procedure	4/1/00
CR 01-0570	Weakness in Operability Justification Process	2/27/01

1R19 Post-Maintenance Testing

TM 01-0003	Diesel Generator Air Start Unit Log	
USAR Section 8.3.1.1.4	Diesel Generator	Rev. 18
TS 3/4/8.1.1	A.C. Sources	Amend. 206
OS-17A,B	Auxiliary Feedwater System	Revs. 16, 17
SD-003B	Emergency Diesel Generators	Rev. 3
USAR Figure 9.5.8	EDG Auxiliary Systems	Rev. 1
OS-041A, Sheets 1&2	EDG Systems	Revs. 18, 15
P&ID M-017A	Diesel Generators	Rev. 16
	Key Work Activities and Surveillances	week of 10/23/01

	Davis-Besse Weekly Maintenance Risk Summary Daily Review	week of 10/23/01
	Work Week Schedule for October 23-26, 2001	
	Key Work Activities and Surveillances	week of 10/29/01
	Davis-Besse Weekly Maintenance Risk Summary Daily Review	week of 10/29/01
	Work Week Schedule for October 29-November 2, 2001	
SD-015	Auxiliary Feedwater System	Rev. 2
USAR Section 1.2.8.2.9	Auxiliary Feedwater System	Rev. 21
USAR Section 10.4.7.2	Auxiliary Feedwater System	Rev. 21

1R23 Temporary Plant Modifications

TM 01-0020	Installation of a Temporary Barrier in place of #3 Service Water Pump	11/2/01
TM 01-0021	Installation of a Temporary Barrier in place of #2 Cooling Tower Makeup Pump	11/2/01

4OA1 Performance Indicator Verification

Key Work Activities and Surveillances

1st, 2nd and 3rd Quarter 2001Davis-Besse System Health Reports

2000 Davis-Besse System Health Reports

Unit Logs

2OS1 Access Control to Radiologically Significant Areas

DP-HP-04033	Spent Fuel Pool Radiological Material Inventory	October 10, 2001
DP-HP-04003	Locked High Radiation Area Boundary Verification	May 4, 2001
DB-HP-01114	Diving Operations in Contaminated Waters	September 17, 2001
01-2959	Entries Into Locked High Radiation Areas	November 5, 2001

01-0027	Radiation Protection Procedure Noncompliance	February 18, 2001
01-0029	Inadequate Administrative Controls During 12 RFO FOSAR Move.	January 4, 2001
01-0306	Dose Set Point Performance Indicator Response	February 1, 2001
01-0441	Contamination Area Boundaries	March 19, 2001
01-0625	Lock Not Secure on the Entrance to an RRA	March 2, 2001
01-0808	Noncompliance with Procedure DB-HP-01232	May 5, 2001
01-0985	Dose Versus Risk Evaluation for Nuclear Filter Changes	June 4, 2001
01-1893	Sign Posting	September 28, 2001
01-2221	SFP Rerack Readiness Enhancement	August 28, 2001
01-2368	Failure to Implement Approved Corrective Actions	September 13, 2001
01-2637	Debris in Cask Pit Sump	October 8, 2001
RWP 2001-2010	Containment Entry to Add Oil to RCP 2-2 Upper Bearing, ALARA Package	October 22, 2001
RWP 2001-1030	Spent Fuel Pool Rerack Work, ALARA Package	November 8, 2001
RWP 2001-1026	Decay Heat Pump #1 Outage	August 8, 2001
RWP 2001-1035	Decay Heat Pump #2 Outage	September 25, 2001
	Surveillance Report: SR-01-RPRWP-06	September 13, 2001
	Self-Assessment Report: SA 2000-0024	November 30, 2000
	Self-Assessment Report: SA 2000-0151	December 18, 2000
	Self-Assessment Report: SA 2001-0107	September 7, 2001
	Self-Assessment Report: SA 2001-0115	August 28, 2001

2OS3 Radiological Instrumentation

DB-HP-01309	Use of the MSA Custom 4500 II SCBA	October 25, 2001
DB-HP-01308	Respiratory Protection Equipment Inspection and Maintenance	January 7, 1998
DB-HP-01301	Use of the MSA Ultra-Twin and Ultra-VUE Respirator	June 10, 1991

	Respirator Qualification Report	October 31, 2001
	D-B Nuclear Quality Assessment Surveillance Report, SR-01-RPRWP-05	June 7, 2001
	Self Assessment Report: RP Instruments and Surveys, SA-2000-0023	November 15, 2000
	Self Assessment Report: Radiological Respiratory Protection Program, SA-2001-0016	February 19, 2001
	Post Accident Sampling System Data	
4597	Containment Vessel High Range Detectors	May 19, 2000
4596	Containment Vessel High Range Detectors	May 19, 2000
8401	Reactor Coolant and Radwaste Sample Room	April 26, 2001
8402	Emergency Core Cooling System	November 13, 2000
8409	Mechanical Penetration Room #1	July 27, 2001
8417	Fuel Handling Area	November 2, 2000
8426	Spent Fuel Pool	May 2, 2001
8446	Fuel Handling Area Exhaust	February 22, 2001
DB-HP 01442	Telepole Calibrations	June 30, 2001
DB-HP 01452	Kurz High Volume Air Sampler Calibrations	August 17, 2001
DB-HP-01432	ASP1 Neutron Detector Calibrations	August 8, 2001
DB-HP-01418	RSO-50 Ion Chamber Calibrations	September 25, 2001
DB-HP-01418	RSO-5 Ion Chamber Calibrations	August 7, 2001
DB-HP-06030	PCM1B Calibrations	August 2, 2001
	Eberline AMS 3 Continuous Air Monitor Calibrations	February 28, 2001
	Whole Body Counter Calibration	
	SAM-9 Tool Monitor Calibrations	December 1, 2000
	AMP 100 Underwater Detector Calibrations	October 10, 2001
01-1461	RP Procedure Enhancement Recommendations	June 4, 2001
01-2940	Containment Radiation Monitors	November 4, 2001
01-2936	Unable to Perform Functional Test	November 3, 2001
01-0456	Shoulder Strap Clip Failed On Training SCBA	February 16, 2001

01-0477	Air Compressor Intake Not Protected from Airborne Contamination	February 19, 2001
01-0481	Procedure Allows Higher Temperature for Respirator Cleaning than OSHA	February 19, 2001
01-0656	Calibration of SAM 11	April 20, 2001
01-1076	Misuse of Retired "Eagle" Air Compressor	June 16, 2001
01-1410	Radiation Monitor Setpoint Manuals	July 14, 2001
01-1549	Portal Monitor Failed Daily Source Check	July 30, 2001

2PS2 Radioactive Material Processing and Transportation

01-1418	RAM Shipment	May 31, 2001
01-0878	Non Compliance Notification for the 10-142B Cask	March 28, 2001
01-0232	10 CFR 61 Procedure Improvement	February 6, 2001
01-0233	Discrepancies Between Operating Procedure and the USAR	February 6, 2001
01-0235	Station Sampling System in the USAR Not Correct	February 6, 2001
DB-HP-04024	10 CFR 61 Sampling For Waste Classification	April 1, 1999
	D-B Process Control Program	April 19, 1999
	Self Assessment Report SA 2001-0002	February 6, 2001
TR01-004	Radioactive Waste Manifest	August 21, 2001
TR01-005	Radioactive Waste Manifest	September 14, 2001
TR01-002	Radioactive Waste Manifest	April 3, 2001
RM01-0009	Radioactive Material Manifest	February 22, 2001
RM01-0022	Radioactive Material Shipment	April 17, 2001

Reference T

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, DC 20555-0001

March 12, 2002

NRC INFORMATION NOTICE 2002-11: RECENT EXPERIENCE WITH DEGRADATION OF REACTOR PRESSURE VESSEL HEAD

Addressees

All holders of operating licenses for pressurized-water reactors (PWRs), except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees about findings from recent inspections and examinations of the reactor pressure vessel (RPV) head at Davis-Besse Nuclear Power Station. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

On February 16, 2002, the Davis-Besse facility began a refueling outage that included inspection of the vessel head penetration (VHP) nozzles, which focused on the inspection of control rod drive mechanism (CRDM) nozzles, in accordance with the licensee's commitments to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," which was issued on August 3, 2001. These inspections identified axial indications in three CRDM nozzles, which had resulted in pressure boundary leakage. Specifically, these indications were identified in CRDM nozzles 1, 2, and 3, which are located near the center of the RPV head. These findings were reported to the NRC on February 27, 2002, and supplemented on March 5 and March 9, 2002. The licensee decided to repair these three nozzles, as well as two other nozzles that had indications but had not resulted in pressure boundary leakage.

The repair process for these nozzles included roll expanding the CRDM nozzle material into the surrounding RPV head material, followed by machining along the axis of the CRDM nozzle to an elevation above the indications in the nozzle material. On March 6, 2002, the machining process on CRDM nozzle 3 was prematurely terminated and the machining apparatus was removed from the nozzle. During the removal process, nozzle 3 was mechanically agitated and subsequently displaced in the downhill direction (i.e., tipped away from the top of the RPV head) until its flange contacted the flange of the adjacent CRDM nozzle.

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To identify the cause of the CRDM nozzle displacement, the licensee began an investigation into the condition of the RPV head surrounding CRDM nozzle 3. This investigation included removing the CRDM nozzle from the RPV head, removing boric acid deposits from the top of the RPV head, and performing ultrasonic thickness measurements of the RPV head in the vicinity of CRDM nozzles 1, 2, and 3. Upon completing the boric acid removal on March 7, 2002, the licensee conducted a visual examination of the area, which identified a large cavity in the RPV head on the downhill side of CRDM nozzle 3. Followup characterization by ultrasonic testing indicated wastage of the low alloy steel RPV head material adjacent to the nozzle. The wastage area was found to extend approximately 5 inches downhill on the RPV head from the penetration for CRDM nozzle 3, with a width of approximately 4 to 5 inches at its widest part. The minimum remaining thickness of the RPV head in the wastage area was found to be approximately ⅜ inch. This thickness was attributed to the thickness of the stainless steel cladding on the inside surface of the RPV head, which is nominally ⅜ inch thick.

Background

The Davis-Besse Nuclear Power Station has an RPV head that is constructed from low alloy steel, fabricated in accordance with the American Society of Mechanical Engineers (ASME) specification SA-533, Grade B, Class1, and clad on the inside surface with stainless steel. Of those 69 VHP nozzles, 61 are used for CRDMs, 7 are spare (empty) nozzles, and 1 is used for the RPV head vent piping. Each of the 69 nozzles is approximately 4 inches in outside diameter, with a wall-thickness of approximately ⅝ inch. Each is constructed of Alloy 600 and is attached to the RPV head by a partial-penetration, J-groove weld using Alloy 82 and 182. The distance from the center of one nozzle to the center of the next is approximately 12 inches.

The vessel head is insulated with metal reflective insulation, which is located on a horizontal plane slightly above the RPV head (i.e., it is not in direct contact with the head). The minimum distance between the RPV head and the insulation is approximately 2 inches at the center (top) of the head. The CRDM nozzles pass from the RPV head through the insulation and terminate at flanges to which the CRDM housings are attached.

The limited gap between the insulation and the RPV head does not impede the performance of a visual inspection of the CRDM nozzles, as described in Bulletin 2001-01. This is because the top of the RPV head is surrounded by a service structure that has 18 openings (referred to as "weep holes") near the bottom of the structure, through which small cameras can be inserted to facilitate visual inspections of the RPV head.

During refueling outages in 1998 and 2000, the licensee performed visual inspections of the RPV head surface that was accessible through the service structure weep holes. The scope of these visual inspections covered the bare metal of the RPV head to identify the presence of boric acid deposits, which would be indicative of primary coolant leakage. These inspections also included checking for leakage from any of the CRDM flanges, located above the insulation, in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components," which the NRC issued on March 17, 1988.

The visual inspections in 1998 showed an uneven layer of boric acid deposits scattered over the RPV head (including deposits near CRDM nozzle 3). The outside diameter of the CRDM nozzles had white streaks, which indicated to the licensee that the boric acid evident on the head flowed downward from leakage in the CRDM flanges.

During the refueling outage in 2000, the licensee also performed visual inspections of the CRDM flanges and nozzles. Above the RPV head insulation, those inspections revealed five CRDM flanges with evidence of leakage, including one flange that was the principal leakage point. Boric acid deposits on the vertical faces of three of these five flanges and the associated nozzles confirmed leakage from the flanges. Similarly, one of the other two leaking CRDM flanges had boric acid deposits between the flange and the insulation, which indicated leakage from the flange. All of these leaking flanges were repaired by replacing their gaskets. The faces of the flange that was the principal leakage point were also machined to ensure a better seal.

Visual inspections performed below the RPV head insulation during the 2000 refueling outage indicated some accumulation of boric acid deposits on the RPV head. These deposits were located beneath the leaking flanges, with clear evidence of downward flow from the flange area. No visible evidence of CRDM nozzle leakage (i.e., leakage from the gap between the nozzle and the RPV head) was detected. The licensee described that the RPV head area was cleaned with demineralized water to the greatest extent possible, while trying to maintain the dose as low as reasonably achievable (ALARA). Subsequent video inspection of the partially cleaned RPV head and nozzles was performed for future reference.

A subsequent review of the 1998 and 2000 inspection videotapes in 2001 confirmed that there was no evidence of leakage from the RPV head nozzles, although many areas of the RPV head were not accessible because of persistent boric acid deposits that the licensee did not clean because of ALARA issues (including the region around nozzle 3).

The inspections in 2002 did not reveal any visual evidence of flange leakage from above the RPV head. However, as discussed above, three CRDM nozzles had indications of cracking (identified by ultrasonic testing of the nozzles), which could result in leakage from the RPV to the top of the RPV head.

Discussion

The following documents describe reactor operating experience with boric acid corrosion of ferritic steel reactor coolant pressure boundary components in PWR plants:

- Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," issued December 29, 1986

- Information Notice 86-108, Supplement 1, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," issued April 20, 1987

- Information Notice 86-108, Supplement 2, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," issued November 19, 1987

- Information Notice 86-108, Supplement 3, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," issued January 5, 1995

- Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," issued March 17, 1988

Several instances of boric acid corrosion discussed in these generic communications are associated with corrosion of the RPV head. NRC Information Notice 86-108, Supplement 1, for example, described an instance in which boric acid had severely corroded three of the RPV flange bolts, the control rod drive shroud support, and an instrument tube seal clamp. Similarly, NRC Information Notice 86-108, Supplement 2, described an instance in which boric acid resulted in nine pits in the surface of the RPV head, ranging in depth from 0.9 to 1 cm [approximately 0.4 inch] and ranging in diameter from 2.5 to 7.5 cm [1 to 3 inches].

As discussed in Information Notice 86-108, Supplement 2, the primary effect of boric acid leakage onto the ferritic steel RPV head is wastage or general dissolution of the material. Pitting, stress corrosion cracking (SCC), intergranular attack, and other forms of corrosion are not generally of concern in concentrated boric acid solutions at elevated temperatures such as those that may occur on the surface of the RPV head. The rate of general corrosion (wastage) of ferritic steel from boric acid varies and depends on several conditions, including whether the boric acid is dry or in solution. If the boric acid is dry (i.e., boric acid crystals), the corrosion rate is less severe; however, boric acid crystals are not completely benign to carbon steel. During operation, the temperature of the RPV head is sufficiently high that any leaking primary coolant would be expected to flash to steam, leaving behind dry boric acid crystals.

Given the wide range of conditions around reactor primary coolant leakage sites and the wide variation in boric acid corrosion rates, the deleterious effects of boric acid on ferritic steel components indicate the importance of minimizing boric acid leakage, detecting and correcting leaks in a timely manner, and promptly cleaning any boric acid residue.

The investigation of the causative conditions surrounding the degradation of the RPV head at Davis-Besse is continuing. Boric acid or other contaminants could be contributing factors. As discussed above, factors contributing to the degradation might also include the environment of the head during both operating and shutdown conditions (e.g., wet/dry), the duration for which the RPV head is exposed to boric acid, and the source of the boric acid (e.g., leakage from the CRDM nozzle or from sources above the RPV head such as CRDM flanges).

<u>Related Generic Communications</u>

Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” August 3, 2001.

Bulletin 82-02, “Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants,” June 2, 1982.

Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” March 17, 1988.

Generic Letter 97-01, “Degradation of Control Rod Drive Mechanism Nozzles and Other Vessel Closure Head Penetrations,” April 1, 1997.

Information Notice 80-27, “Degradation of Reactor Coolant Pump Studs,” June 11, 1980.

Information Notice 82-06, “Failure of Steam Generator Primary Side Manway Closure Studs,” March 12, 1982.

Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," December 29, 1986.

Information Notice 86-108, Supplement 1, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," April 20, 1987.

Information Notice 86-108, Supplement 2, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," November 19, 1987.

Information Notice 86-108, Supplement 3, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," January 5, 1995.

Information Notice 90-10, "Primary Water Stress Corrosion Cracking of INCONEL 600," February 23, 1990.

Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks," August 30, 1994.

Information Notice 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," February 14, 1996.

Information Notice 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3," April 30, 2001.

This information notice does not require any specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate project manager in the NRC's Office of Nuclear Reactor Regulation (NRR).

/RA/
William D. Beckner, Program Director
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Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," December 29, 1986.

Information Notice 86-108, Supplement 1, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," April 20, 1987.

Information Notice 86-108, Supplement 2, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," November 19, 1987.

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/RA/
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DATE	03/11/2002	03/11/2002	03/11/2002	03/11/2002	03/12/2002

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LIST OF RECENTLY ISSUED
NRC INFORMATION NOTICES

Information Notice No.	Subject	Date of Issuance	Issued to
2002-10	Nonconservative Water Level Setpoints on Steam Generators	03/07/2002	All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.
2002-09	Potential for Top Nozzle Separation and Dropping of Certain Type of Westinghouse Fuel Assembly	02/13/2002	All holders of operating licenses for nuclear power reactors, and non-power reactors and holders of licenses for permanently shutdown facilities with fuel onsite.
2002-08	Pump Shaft Damage Due to Excessive Hardness of Shaft Sleeve	01/30/2002	All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.
2002-07	Use of Sodium Hypochlorite for Cleaning Diesel Fuel Oil Supply Tanks	01/28/2002	All holders of operating licenses for nuclear power except those who have ceased operations and have certified that fuel has been permanently removed from the reactor vessel.
2002-06	Design Vulnerability in BWR Reactor Vessel Level Instrumentation Backfill Modification	01/18/2002	All holders of operating licenses or construction permits for boiling water reactors (BWRs).
2002-05	Foreign Material in Standby Liquid Control Storage Tanks	01/17/2002	All holders of licenses for nuclear power reactors.
2002-04	Wire Degradation at Breaker Cubicle Door Hinges	01/10/2002	All holders of operating licenses for nuclear power reactors.

OL = Operating License
CP = Construction Permit

Reference U

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

April 1, 1997

NRC GENERIC LETTER 97-01: DEGRADATION OF CONTROL ROD DRIVE MECHANISM NOZZLE AND OTHER VESSEL CLOSURE HEAD PENETRATIONS

Addressees

All holders of operating licenses for pressurized water reactors (PWRs), except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this generic letter to (1) request addressees to describe their program for ensuring the timely inspection of PWR control rod drive mechanism (CRDM) and other vessel closure head penetrations and (2) require that all addressees provide to the NRC a written response to the requested information. The information requested is needed by the NRC staff to verify compliance with 10 CFR 50.55a and 10 CFR Part 50, Appendix A, GDC 14, and to determine whether an augmented inspection program, pursuant to 10 CFR 50.55a(g)(6)(ii), is required.

Background

Primary Water Stress Corrosion Cracking of Vessel Closure Head Penetrations

Most PWRs have Alloy 600 CRDM nozzle and other vessel head closure penetrations (VHPs) that extend above the reactor pressure vessel head. The stainless steel housing of the CRDM is screwed and seal-welded onto the top of the nozzle penetration, as shown in Figure 1. (Figure 1 is for illustrative purposes only and is not intended to be indicative of every nuclear steam supply system (NSSS) vendor's CRDM design.) The weld between the nozzle top and bottom pieces is a dissimilar metal weld, which is also called a bimetallic weld. The nozzles protrude below the vessel head, thus exposing the inside surface of the nozzles to reactor coolant. The CRDM nozzle and other VHPs are basically the same for all PWRs worldwide, which use a U.S. design (except in Germany and Russia). The areas of interest for potential cracking are the weld between the nozzle and reactor vessel head, and the portion of the nozzle inside the reactor vessel head above the nozzle-to-vessel weld.

Generally, there are 36 to 78 nozzles distributed over the low-alloy steel head. The vessel head is semi-spherical and the head penetrations are vertical so that the CRDM nozzle and other VHPs are not perpendicular to the vessel surface except at the center. The uphill side (toward the center of the head) is called the 180-degree location and the downhill side (toward the outer periphery of the head) is called the 0-degree location. Most nozzles have a thermal sleeve with a conical guide at the bottom end and a small gap (3- to 4-mm) [0.12 to 0.16 in.] between the nozzle and the sleeve.

Beginning in 1986, leaks have been reported in several Alloy 600 pressurizer instrument nozzles at both domestic and foreign reactors from several different NSSS vendors. The NRC staff identified primary water stress corrosion cracking (PWSCC) as an emerging technical issue to the Commission in 1989, after cracking was noted in Alloy 600 pressurizer heater sleeve penetrations at a domestic PWR facility. The NRC staff reviewed the safety significance of the cracking that occurred, as well as the repair and replacement activities at the affected facilities. The NRC staff determined that the cracking was not of immediate safety significance because the cracks were axial, had a low growth rate, were in a material with an extremely high flaw tolerance (high fracture toughness) and, accordingly, were unlikely to propagate very far. These factors also demonstrated that any cracking would result in detectable leakage and the opportunity to take corrective action before a penetration would fail. Further, with the exception of the leak found at Bugey 3 during hydrostatic testing, the NRC staff is not aware of any failure of an Alloy 600 vessel closure head penetration during plant operation. The NRC staff issued Information Notice (IN) 90-10, "Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600," dated February 23, 1990, to inform the nuclear industry of the issue.

In September 1991, cracks were found in an Alloy 600 VHP in the reactor head at Bugey 3, a French PWR. Examinations in PWRs in France, Belgium, Sweden, Switzerland, Spain, and Japan were performed, and additional VHPs with axial cracks were detected in several European plants. About 2 percent of the VHPs examined to date contain short, axial cracks. Close examination of the VHP that leaked at Bugey 3 revealed very minor incipient secondary circumferential cracking of the VHP. European and Japanese utilities have taken steps to detect and mitigate the PWSCC damage and to detect the leakage at an early stage. European and Japanese utilities have inspected most of the CRDM nozzles and repaired the nozzles or replaced the vessel heads as appropriate. In Japan, the three most susceptible vessel heads are being replaced, even though no cracks were found in the nozzles of these heads. In France, Élecricité de France (EdF) is planning on replacing all vessel heads as a preventative measure. Inservice inspection of the upper head is now required in Sweden. Removable insulation on the vessel head and leakage monitoring systems are installed at French and Swedish plants for early detection of leakage.

An action plan was implemented by the NRC staff in 1991 to address PWSCC of Alloy 600 VHPs at all U.S. PWRs. As explained more fully below, this action plan included a review of the safety assessments by the PWR Owners Groups, the development of VHP mock-ups by the Electric Power Research Institute (EPRI), the qualification of inspectors on the VHP mock-ups by EPRI, the review of proposed generic acceptance criteria from the Nuclear Utility Management and Resource Council (NUMARC) [now the Nuclear Energy Institute (NEI)], and VHP inspections. As part of this action plan, the NRC staff met with the Westinghouse Owners Group (WOG) on January 7, 1992, the Combustion Engineering Owners Group (CEOG) on March 25, 1992, and the Babcock & Wilcox Owners Group (B&WOG) on May 12, 1992, to discuss their respective programs for investigating PWSCC of Alloy 600 and to assess the possibility of cracking of VHPs in their respective plants since all of the plants have Alloy 600 VHPs. Subsequently, the NRC staff asked NUMARC to coordinate future industry actions because the issue was applicable to all PWRs. Meetings were held with NUMARC/NEI and the PWR Owner's Groups on the issue on August 18 and November 20, 1992, March 3, 1993, December 1, 1994, and August 24, 1995. Summaries of these meetings are available in the Commission's Public Document Room, 2120 L Street, N.W., Washington, D.C. 20555.

Each of the PWR Owners Groups submitted safety assessments, dated February 1993, through NUMARC to the NRC on this issue. After reviewing the industry's safety assessments and examining the overseas inspection findings, the NRC staff concluded in a safety evaluation dated November 19, 1993, that VHP cracking was not an immediate safety concern. The bases for this conclusion were that if PWSCC occurred at VHPs (1) the cracks would be predominately axial in orientation, (2) the cracks would result in detectable leakage before catastrophic failure, and (3) the leakage would be detected during visual examinations performed as part of surveillance walkdown inspections before significant damage to the reactor vessel closure head would occur. In addition, the NRC staff had concerns related to unnecessary occupational radiation exposures associated with eddy current or other forms of nondestructive examinations (NDEs), if performed manually. Field experience in foreign countries has shown that occupational radiation exposures can be significantly reduced by using remotely controlled or automatic equipment to conduct the inspections.

In 1993, the nuclear industry developed remotely operated inservice inspection equipment and repair tools that reduced radiation exposure. Techniques and procedures developed by two vendors were successfully demonstrated in a blind qualification protocol developed and administered by the EPRI NDE Center. In the demonstrations, examinations by rotating and saber eddy current and ultrasonics showed a high probability of detection of the flaws which were also sized within reasonable uncertainty bounds. The qualification testing also demonstrated that personnel qualified through the EPRI program can reliably detect PWSCC in CRDM nozzles.

Intergranular Attack of CRDM Penetration Nozzle at Zorita

In 1994, circumferential intergranular attack (IGA) associated with the weld between the inner surface of the reactor closure head and the CRDM penetration (usually referred to as the J-grove weld) in one of the CRDM penetrations was discovered at Zorita, a Spanish reactor. This IGA is a different degradation mechanism than the PWSCC described above. It is believed to have resulted from the combination of ion exchange resin bead intrusions, which resulted in high concentrations of sulfates. Zorita has 37 CRDM penetrations, of which 20 are active penetrations and 17 are spare penetrations. Sixteen of the 17 spare penetrations showed stress corrosion cracking and IGA. The cracks were both axial and circumferential. Four of the active CRDM penetrations had significant cracking with axial and circumferential cracks. Two cation resin ingress events occurred at Zorita. In August 1980, 40 liters [10.57 U.S. gallons] of cation resin entered the reactor coolant system (RCS). In September 1981, a mixed bed demineralizer screen failed and between 200 to 320 liters [52.83 to 84.54 U.S. gallons] of resin entered the RCS. The coolant conductivity remained high for at least 4 months after the ingress. The increase in conductivity was attributed to locally high concentrations of sulfates. Sulfates were found around the crack areas and on the fracture surfaces. It is important to note that sulfate cracking can occur in regions that are not subject to significant applied or residual stresses.

The NRC staff issued IN 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," dated February 14, 1996, to alert addressees to the increased likelihood of sulfate-driven stress corrosion cracking of PWR CRDMs and other VHPs if demineralizer resins contaminate the RCS.

Westinghouse notified the WOG plants, the B&WOG plants, and the CEOG plants of the Zorita incident by issuing NSAL-94-028. Westinghouse reported that no other plant had been found worldwide that had experienced cracking similar to that at the Zorita plant. Westinghouse further reported that U.S. plants monitor RCS conductivity on a routine basis, follow the EPRI guidelines on primary water chemistry, and monitor for sulfate three times a week. Westinghouse concluded that no immediate safety issue is involved and that the conclusions in its CRDM safety evaluation remain valid. Westinghouse suggested that U.S. PWR plants review their RCS chemistry and other operating records pertaining to sulfur ingress events. The results of this review have not been reported to the NRC staff, and the NRC staff does not have sufficient information to ascertain whether any significant primary system resin bead intrusions have occurred at any U.S. PWR.

The first U.S. inspection of VHPs took place in the spring of 1994 at the Point Beach Nuclear Generating Station, and no indications were detected in any of its 49 CRDM penetrations. The eddy current inspection at the Oconee Nuclear Generating Station in the fall of 1994 revealed 20 indications in one penetration. Ultrasonic testing (UT) did not reveal the depth of these indications because they were shallow. UT cannot accurately size defects that are less than one mil deep (0.03 mm). These indications may be associated with the original fabrication and may not grow; however, they will be reexamined during the next refueling outage. A limited examination of eight in-core instrumentation penetrations conducted at the Palisades plant found no cracking. An examination of the CRDM penetrations at the D. C. Cook plant in the fall of 1994 revealed three clustered indications in one penetration. The indications were 46 mm [1.81 in.], 16 mm [0.63 in.], and 6 to 8 mm [0.24 to 0.31 in.] in length, and the deepest flaw was 6.8 mm [0.27 in.] deep. The tip of the 46-mm [1.81 in.] flaw was just below the J-groove weld.

Virginia Electric and Power Company inspected North Anna Unit 1 during its spring 1996 refueling outage. Some high-stress areas (e.g., upper and lower hillsides) were examined on each outer ring CRDM penetrations and no indications were observed using eddy current testing.

The NRC staff was informed during a meeting on August 24, 1995, that Westinghouse had developed a susceptibility model for VHPs based on a number of factors, including operating temperature, years of power operation, method of fabrication of the VHP, microstructure of the VHP, and the location of the VHP on the head. Each time a plant's VHPs are inspected, the inspection results are incorporated into the model. All domestic Westinghouse PWRs have been modeled and the ranking has been given to each licensee. In addition, the NRC staff was informed that Framatome Technologies, Inc. [FTI, formerly Babcock & Wilcox (B&W)], also developed a susceptibility model for CRDM penetration nozzles and other VHPs in B&W reactor vessel designs. All domestic B&W PWRs have been modeled and the ranking has been given to each B&W licensee. The NRC staff was further informed that Combustion Engineering (CE) had performed an initial susceptibility assessment for the CE PWRs. At present, none of the PWR Owners Groups (i.e., WOG, B&WOG, or CEOG) has submitted its models and assessments to the NRC staff for review.

By letter dated March 5, 1996, NEI submitted a white paper entitled "Alloy 600 RPV Head Penetration Primary Stress Corrosion Cracking," which reviews the significance of PWSCC in PWR VHPs and describes how the industry is managing the issue. The program outlined in the NEI white paper is based on the assumption that the issue is primarily an economic rather than a safety issue, and describes an economic decision tool to be used by PWR licensees to evaluate the probability of a VHP developing a crack or a through-wall leak during a plant's lifetime. This information would then be used by a PWR licensee to evaluate the need to conduct a VHP inspection at their plant. The NRC staff informed NEI in the several meetings listed above that it did not agree with NEI that the issue was primarily economic.

<u>Discussion</u>

The results of domestic VHP inspections are consistent with the February 1993 analyses by the PWR Owners Groups, the NRC staff safety evaluation report dated November 19, 1993, and the PWSCC found in the CRDMs in European reactors. On the basis of the results of the first five inspections of U.S. PWRs, the PWR Owner's Groups' analyses, and the European experience, the NRC staff has determined that it is probable that VHPs at other plants contain similar axial cracks. Further, if any significant resin intrusions have occurred at U.S. PWRs such as occurred at Zorita, residual stresses are sufficient to cause circumferential intergranular stress corrosion cracking (IGSCC).

After considering this information, the NRC staff has concluded that VHP cracking does not pose an immediate or near term safety concern. Further, the NRC staff recognizes that the scope and timing of inspections may vary for different plants depending on their individual susceptibility to this form of degradation. In the long term, however, degradation of the CRDM and other VHPs is an important safety consideration that warrants further evaluation. The vessel closure head provides the vital function of maintaining reactor pressure boundary. Cracking in the VHPs has occurred and is expected to continue to occur as plants age. The NRC staff considers cracking of VHPs to be a safety concern for the long term based on the possibility of (1) exceeding the American Society of Mechanical Engineers (ASME) Code for margins if the cracks are sufficiently deep and continue to propagate during subsequent operating cycles, and (2) eliminating a layer of defense in depth for plant safety. Therefore, to verify that the margins required by the ASME Code, as specified in Section 50.55a of Title 10 of the *Code of Federal Regulations* (10 CFR 50.55a) are met, that the guidance of General Design Criterion 14 of Appendix A to 10 CFR Part 50 (10 CFR Part 50, Appendix A, GDC 14) is continued to be satisfied, and to ensure that the safety significance of VHP cracking remains low, the NRC staff continues to believe that an integrated, long-term program, which includes periodic inspections and monitoring of VHPs, is necessary. This was the conclusion of the staff's November 19, 1993, safety evaluation, which stated, in part, "...the staff recommends that you consider enhanced leakage detection by visually examining the reactor vessel head until either inspections have been completed showing absence of cracking or on-line leakage detection is installed in the head area ... nondestructive examinations should be performed to ensure there is no unexpected cracking in domestic PWRs. These examinations do not have to be conducted immediately ... As the surveillance walkdowns proposed by NUMARC are not intended for detecting small leaks, it is conceivable that some affected PWRs could potentially operate with small undetected leakage at CRDM/CEDM penetrations. In this regard, the staff believes that it is prudent for NUMARC to consider the implementation of an enhanced leakage detection method for detecting small leaks during plant operation." In addition, the NRC staff finds that the requested information is also needed to determine if the imposition of an augmented inspection program, pursuant to 10 CFR 50.55a(g)(6)(ii), is required to maintain public health and safety.

The NRC staff recognizes that individual PWR licensees may wish to determine their inspection activities based on an integrated industry inspection program (i.e., B&WOG, CEOG, WOG, or some subset thereof), to take advantage of inspection results from other plants that have similar susceptibilities. The NRC staff does not discourage such group actions but notes that such an integrated industry inspection program must have a well-founded technical basis that justifies the relationship between the plants and the planned implementation schedule.

Requested Information

The information requested in item 1 is needed by the NRC staff to verify compliance with 10 CFR 50.55a and 10 CFR Part 50, Appendix A, GDC 14, and to determine whether an augmented inspection program of the weld between the penetration nozzle and reactor vessel head as well as the portion of the nozzle above the weld is required, pursuant to 10 CFR 50.55a(g)(6)(ii), while the information requested in item 2 relates to the occurrence of resin bead intrusion in PWRs, such as occurred at Zorita.

Within 120 days of the date of this generic letter, each addressee is requested to provide a written report that includes the following information for its facility:

1. Regarding inspection activities:

   1.1 A description of all inspections of CRDM nozzle and other VHPs performed to the date of this generic letter, including the results of these inspections[1].

   1.2 If a plan has been developed to periodically inspect the CRDM nozzle and other VHPs:

      a. Provide the schedule for first, and subsequent, inspections of the CRDM nozzle and other VHPs, including the technical basis for this schedule.

      b. Provide the scope for the CRDM nozzle and other VHP inspections, including the total number of penetrations (and how many will be inspected), which penetrations have thermal sleeves, which are spares, and which are instrument or other penetrations.

   1.3 If a plan has not been developed to periodically inspect the CRDM nozzle and other VHPs, provide the analysis that supports why no augmented inspection is necessary.

   1.4 In light of the degradation of CRDM nozzle and other VHPs described above, provide the analysis that supports the selected course of action as listed in either 1.2 or 1.3, above. In particular, provide a description of all relevant data and/or tests used to develop crack initiation and crack growth models, the methods and data used to validate these models, the plant-specific inputs to these models, and how these models substantiate the susceptibility evaluation. Also, if an integrated industry inspection program is being relied on, provide a detailed description of this program.

2. Provide a description of any resin bead intrusions, as described in IN 96-11, that have exceeded the current EPRI PWR Primary Water Chemistry Guidelines recommendations for primary water sulfate levels, including the following information:

   2.1 Were the intrusions cation, anion, or mixed bed?

   2.2 What were the durations of these intrusions?

   2.3 Does the plant's RCS water chemistry Technical Specifications follow the EPRI guidelines?

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[1] Those licensees that have previously submitted the requested information need not resubmit it, but may instead reference the appropriate correspondence in their response to this Generic Letter.

2.4 Identify any RCS chemistry excursions that exceed the plant administrative limits for the following species: sulfates, chlorides or fluorides, oxygen, boron, and lithium.

2.5 Identify any conductivity excursions which may be indicative of resin intrusions. Provide a technical assessment of each excursion and any followup actions.

2.6 Provide an assessment of the potential for any of these intrusions to result in a significant increase in the probability for IGA of VHPs and any associated plan for inspections.

Required Response

Within 30 days of the date of this generic letter, each addressee is required to submit a written response indicating: (1) whether or not the requested information will be submitted and (2) whether or not the requested information will be submitted within the requested time period. Addressees who choose not to submit the requested information, or are unable to satisfy the requested completion date, must describe in their response any alternative course of action that is proposed to be taken, including the basis for the acceptability of the proposed alternative course of action.

NRC staff will review the responses to this generic letter and if concerns are identified, affected addressees will be notified.

Address the required written reports to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555, under oath or affirmation under the provisions of Section 182a, Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f). In addition, submit a copy to the appropriate regional administrator.

The NRC recognizes the potential difficulties (number and types of sources, age of records, proprietary data, etc.) that licensees may encounter while ascertaining whether they have all of the data pertinent to the evaluation of their CRDM nozzles and other VHPs. For this reason, the above time periods are allowed for the responses.

Related Generic Communications

(1) Information Notice 90-10, "Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600," dated February 23, 1990.

(2) NUREG/CR-6245, "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking," dated October 1994.

(3) Information Notice 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," dated February 14, 1996.

Backfit Discussion

Under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), this generic letter transmits an information request for the purpose of verifying compliance with applicable existing regulatory requirements. Specifically, the requested information would enable the NRC staff to determine whether or not the licensees' margins required by the ASME Code, as specified in Section 50.55a of Title 10 of the *Code of Federal Regulations* (10 CFR 50.55a) are met, that the guidance of General Design Criterion 14 of Appendix A to 10 CFR Part 50 (10 CFR Part 50, Appendix A, GDC 14) continues to be satisfied, and to ensure that the safety significance of VHP cracking remains low. The requested information is also needed to determine whether an augmented inspect- tion program, pursuant to 10 CFR 50.55a(g)(6)(ii), is required to maintain public health and safety.

Additionally, no backfit is either intended or approved in the context of issuance of this generic letter. Therefore, the staff has not performed a backfit analysis.

Federal Register Notification

A notice of opportunity for public comment was published in the *Federal Register* (61 FR 40253) on August 1, 1996, and extended on August 22, 1996 (61 FR 43393). Comments were received from seven licensees, two industry organizations, and one Code Committee. Copies of the staff evaluation of these comments have been made available in the public document room.

Paperwork Reduction Act Statement

This generic letter contains information collections that are subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.). These information collections were approved by the Office of Management and Budget, approval number 3150-0011, which expires July 31, 1997.

The public reporting burden for this collection of information is estimated to average 80 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. The U.S. Nuclear Regulatory Commission is seeking public comment on the potential impact of the collection of information contained in the generic letter and on the following issues:

1. Is the proposed collection of information necessary for the proper performance of the functions of the NRC, including whether the information will have practical utility?

2. Is the estimate of burden accurate?

3. Is there a way to enhance the quality, utility, and clarity of the information to be collected?

4. How can the burden of the collection of information be minimized, including the use of automated collection techniques?

Send comments on any aspect of this collection of information, including suggestions for reducing this burden, to the Information and Records Management Branch, T-6 F33, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0011), Office of Management and Budget, Washington, DC 20503.

The NRC may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

If you have any questions about this matter, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

signed by

Thomas T. Martin, Director
Division of Reactor Program Management
Office of Nuclear Reactor Regulation

Technical contacts: Keith R. Wichman
(301) 415-2757
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James Medoff
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Lead Project Manager: C. E. Carpenter, Jr.
(301) 415-2169
E-mail: cec@nrc.gov

Attachments:
1. Figure 1. Typical Control Rod Drive Mechanism Nozzle

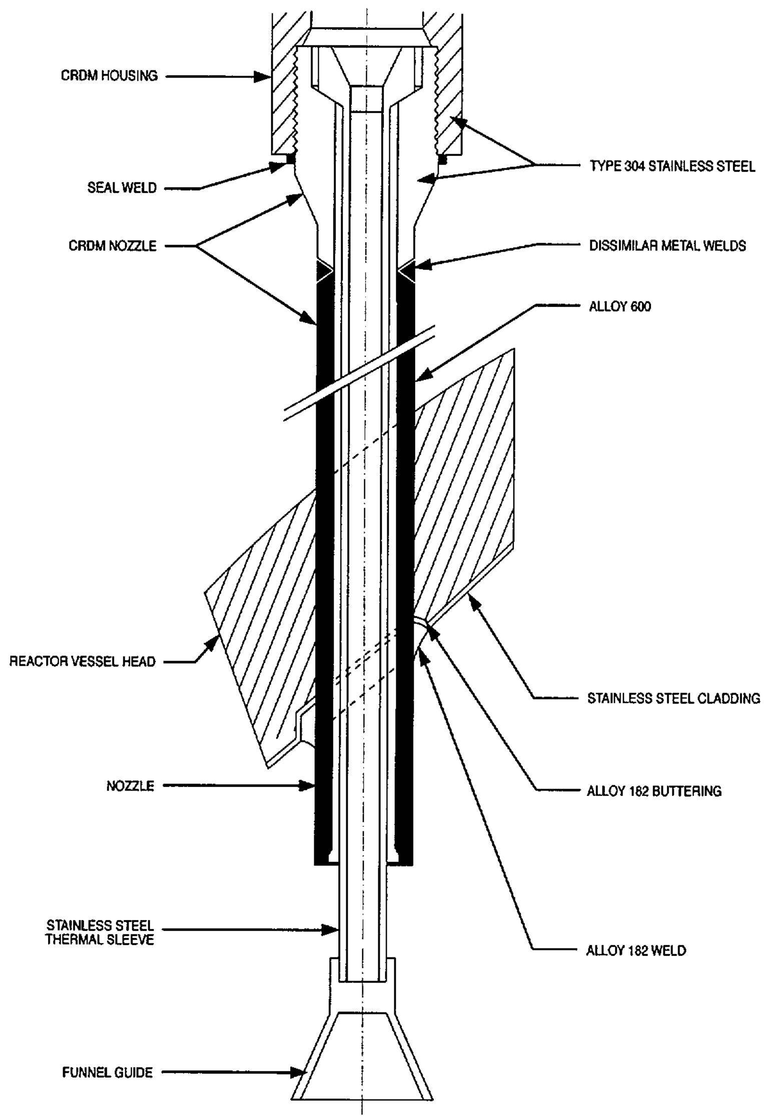

Figure 1. Typical control rod drive mechanism nozzle.
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Reference V

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

March 28, 2000

NRC REGULATORY ISSUE SUMMARY 2000-07 USE OF RISK-INFORMED DECISIONMAKING IN LICENSE AMENDMENT REVIEWS

Addressees

All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

Intent

The U.S. Nuclear Regulatory Commission (NRC) is issuing this regulatory issue summary (RIS) to advise addressees of interim guidance on the use of risk information by the staff in its license amendment reviews, including reviews of license amendment requests that are not risk informed, and staff plans for finalizing this guidance. This RIS requires no action or written response on the part of an addressee.

Background Information

Commission policy, as presented in the Probabilistic Risk Assessment Policy Statement and the "Discussion on Safety and Compliance" (COMSAJ-97-008), indicates that it is the staff's responsibility to consider the change in risk, as well as compliance with the agency's regulations and other requirements, when reviewing license amendment requests. The use of risk information is clear when the action is a risk-informed license amendment request. However, the staff's responsibilities and authority for considering risk information and the Commission's policy regarding the use of risk information in regulatory decisionmaking are not explicitly stated or defined for license amendment requests that are not risk informed (i.e., their acceptability is based solely on meeting the Commission's deterministic rules and regulations).

The recent technical review of steam generator electrosleeves discussed in SECY-99-199, "Electrosleeve Amendment Issued to Union Electric Company for Callaway Plant, Unit 1," illustrates the difficulty of completing a review of a proposed license amendment request that is not risk informed and that satisfies existing design and licensing bases but introduces new potential risks. As a result of this experience, the staff proposed an approach for applying risk informed decisionmaking in similar technical reviews in SECY-99-246, "Proposed Guidelines for Applying Risk Informed Decisionmaking in License Amendment Reviews." In the related staff requirements memorandum, the Commission approved the approach and its implementation on an interim basis while the staff proceeds to engage stakeholders in the development of final guidance.

This RIS transmits the interim guidance on the use of risk information in regulatory decisionmaking regarding license amendment requests and describes the planned approach for finalizing this guidance.

Summary of Issue

When a license amendment request complies with the regulations and other license requirements, there is a presumption by the Commission of adequate protection of public health and safety (Maine Yankee, ALAB-161, 6 AEC 1003 (1973)). However, circumstances may arise in which new information reveals an unforeseen hazard or a substantially greater potential for a known hazard to occur, such as identification of a design vulnerability or an issue that substantially increases risk. In such situations, the NRC has the statutory authority to require licensee action above and beyond existing regulations to maintain the level of protection necessary to avoid undue risk to public health and safety. Section 182.a of the Atomic Energy Act of 1954, as amended, and as implemented by 10 CFR 2.102, gives the NRC the authority to require the submittal of information in connection with a license amendment request if NRC has reason to question adequate protection of public health and safety. The applicant may decline to submit such information, but it would risk having the amendment request denied if NRC cannot find that the requested amendment provides adequate protection of public health and safety.

Under unusual circumstances that could introduce significant and unanticipated risks, the NRC staff would assume the burden of demonstrating that protection is not adequate or that additional license conditions are justified despite the fact that current regulatory requirements appear to be met. Instances in which the staff would question licensees regarding risk are expected to be relatively rare.

The guidelines presented in SECY-99-246 for identifying those situations in which risk implications are appropriate to consider and for deciding if undue risk exists are described in Attachment 1 to this RIS. These guidelines will be used on an interim basis while the staff proceeds to engage stakeholders in the development of final guidance.

The staff will develop final guidelines that articulate what constitutes a special circumstance in a clear and objective manner and modifications to relevant guidance documents to incorporate this guidance. In particular, the staff will modify the regulatory guidance found in Regulatory Guide (RG) 1.174 to describe the concept of special circumstances and the staff's role in reviewing the risk implications of license amendment requests that are not risk informed. The staff will also evaluate whether any regulatory guides or standard review plans in deterministic review areas need to be modified to sensitize the technical staff to identifying potential risk implications of licensing changes within their deterministic review scope. The staff will ensure that both internal and external stakeholders are meaningfully engaged in the development of the final guidelines and related guidance documents.

The staff will subsequently reflect this information in internal, office-level documents that establish the process for reviewing license amendment requests, such as Office of Nuclear Reactor Regulation Office Letter 803, "License Amendment Review Procedures." In modifying the process documents, the staff will be careful to clearly differentiate the concept of adequate protection from the numerical risk acceptance guidelines of RG 1.174.

Backfit Discussion

This RIS requires no action or written response. Consequently, the staff did not perform a backfit analysis.

Federal Register Notification

The staff did not publish a notice of opportunity for public comment in the *Federal Register* because the RIS is informational and pertains to a staff position that does not represent a departure from current regulatory requirements and practice. NRC intends to work with the Nuclear Energy Institute, industry representatives, members of the public, and other stakeholders in developing final guidance and modifying related guidance documents.

If there are any questions about this matter, please contact the person listed below.

/RA by Ledyard Marsh Acting For/
David B. Matthews, Director
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Technical Contact: Robert L. Palla, NRR
301-415-1095
E-mail: rlp3@nrc.gov

Attachments:
1. Interim Guidelines for Using Risk Information in Regulatory Decisionmaking
2. List of Recently Issued NRC Regulatory Issue Summaries

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This RIS requires no action or written response. Consequently, the staff did not perform a backfit analysis.

Federal Register Notification

The staff did not publish a notice of opportunity for public comment in the *Federal Register* because the RIS is informational and pertains to a staff position that does not represent a departure from current regulatory requirements and practice. NRC intends to work with the Nuclear Energy Institute, industry representatives, members of the public, and other stakeholders in developing final guidance and modifying related guidance documents.

If there are any questions about this matter, please contact the person listed below.

/RA by Ledyard Marsh Acting For/
David B. Matthews, Director
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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Attachments:
1. Interim Guidelines for Using Risk Information in Regulatory Decisionmaking
2. List of Recently Issued NRC Regulatory Issue Summaries

*See Previous Concurrence Accession #: ML003680058 Template #: NRR-052

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DATE	2/9/00		2/28/00		3/23/00		3/23/00		3/24/00	

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Attachment 1

Interim Guidelines for Using Risk Information in Regulatory Decisionmaking

The process depicted in Figure 1 will be used in the staff review of both licensee-initiated risk-informed license amendment requests, as well as license amendment requests in which the licensee chooses to not submit risk information.

The staff will assess the requested changes and the need for and effectiveness of any compensatory measures that might be warranted because of risk considerations by evaluating the changes relative to the safety principles and integrated decisionmaking process defined in Regulatory Guide (RG) 1.174. The risk acceptance guidelines (Sections 2.2.4 and 2.2.5 of RG 1.174) describe acceptable levels of risk increase as a function of total core damage frequency (CDF) and large early release frequency and the manner in which the acceptance guidelines should be applied in the review and decisionmaking process. The guidelines serve as a point of reference for gauging risk impact but are not legally binding requirements.

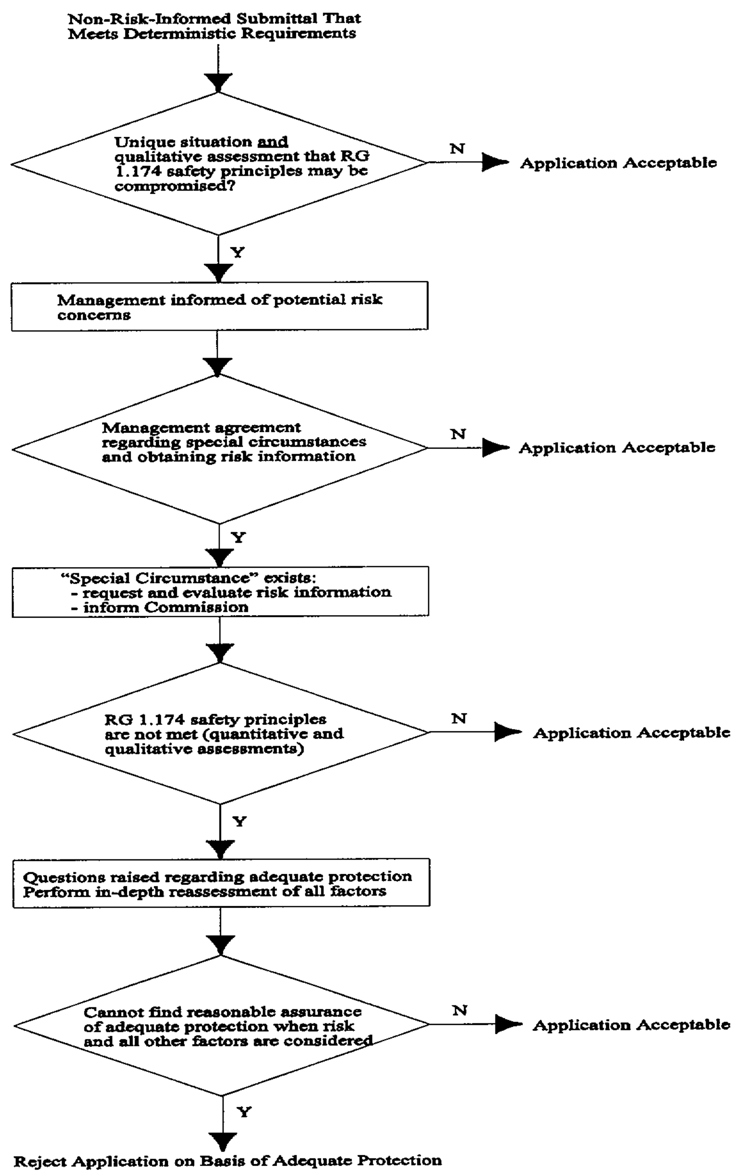
For non-risk-informed license amendment requests, the preliminary assessment would be qualitative with a decision based on engineering judgment since quantitative risk information would not generally be presented in submittals that are not risk informed. If "special circumstances" are believed to exist, the staff will explore in more detail the underlying engineering issues contributing to the risk concern, and the potential risk significance of the license amendment request. These "special circumstances" represent conditions or situations that would raise questions about whether there is adequate protection and that could rebut the normal presumption of adequate protection from compliance with existing requirements. The application and related issues would be given increased attention from the U.S. Nuclear Regulatory Commission management at this point.

With management concurrence, the staff will question risk further if there is a reason to believe that the proposed change would compromise the safety principles described in RG 1.174 and would substantially increase risk relative to the risk acceptance guidelines contained in the regulatory guide. In such instances, the staff will ask the licensee to address the safety principles and the numerical guidelines for acceptable risk increases contained in RG 1.174 in the submittal. The staff may ask the licensee to submit the information it needs to make an appropriate risk assessment. If an applicant does not choose to address risk, the NRC staff will not issue the requested amendment until it has assessed the risk implications sufficiently to determine that there is reasonable assurance that the public health and safety will be adequately protected if the amendment request is approved. A licensee's decision not to submit requested information could impede the staff's review and could also prevent the staff from reaching a finding that there is reasonable assurance of adequate protection. A licensee's failure to submit requested information could also be a basis for rejection pursuant to 10 CFR 2.108.

The staff will inform the Commission if it determines that a license amendment application meets the "special circumstances" standard, the basis for that determination, the licensee's response to the staff's determination, any delay in the license amendment review process, and any generic implications.

Situations that exceed RG 1.174 guidance could constitute a trigger point at which questions are raised as to whether the proposed change provides reasonable assurance of adequate protection. A more in-depth assessment of the special circumstances, the safety principles, and the issues identified for management attention in Section 2.2.6 of RG 1.174 would then be made in order to reach a conclusion regarding the level of safety associated with the requested change. The final acceptability of the proposed change would be based on a consideration of current regulatory requirements, as well as on adherence to the safety principles, and not solely on the basis of a comparison of quantitative probabilistic risk assessment results with numerical acceptance guidelines. The authority provided by the Atomic Energy Act and current regulations requires rejection of a license amendment request if the NRC finds that adequate protection is not provided.

Figure 1 - Process and Logic for Considering Risk in License Amendment Reviews



LIST OF RECENTLY ISSUED
NRC REGULATORY ISSUE SUMMARIES

Regulatory Issue Summary No.	Subject	Date of Issuance	Issued to
2000-06	Consolidated Line Item Improvement Process for Adopting Standard Technical Specifications Changes for Power Reactors	03/20/2000	All holders of OLs for nuclear reactors, except for those licensees who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel
2000-05	Resolution of Generic Safety Issue 165, Spring-Actuated Safety and Relief Valve Reliability	03/16/2000	All holders of OLs for nuclear reactors, except for those licensees who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel
2000-04	Operating Reactor Licensing Action Estimates	03/16/2000	All power reactor licensees
2000-03	Resolution of Generic Safety Issue 158: Performance of Safety-Related Power-Operated Valves Under Design Basis Conditions	03/15/2000	All holders of OLs for nuclear reactors, except for those licensees who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel
2000-02	Closure of Generic Safety Issue 23, Reactor Coolant Pump Seal Failure	02/15/2000	All holders of OLs for nuclear reactors, except for those licensees who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel

OL = Operating License
CP = Construction Permit

Reference W

STATUS OF NRC STAFF REVIEW

OF FENOC'S BULLETIN 2001-01 RESPONSE FOR DAVIS-BESSE

- Brief for the Commissioners' TAs
- November 30, 2001

AGENDA FOR DISCUSSION

- Purpose
  - To discuss the results of the staff's ongoing assessment of FENOC's responses to Bulletin 2001-01 for Davis-Besse
  - To discuss the change in the staff's decision regarding issuance of an Order
- Success
  - Commissioners' TAs understand the basis for the staff's decisions regarding responses to Bulletin 2001-01 for Davis-Besse
- Introduction and discussion of changes - Larry Burkhart (5 minutes)
- Discussion of status of staff's review - Jack Strosnider and Rich Barrett (15 minutes)

CHANGE IN LICENSEE'S PLANS/COMMITMENTS

- The Licensee proposed changing its commitments to include
  - Commencing its refueling outage on February 16, 2002, vice March 31, 2002,
  - Perform a qualified visual inspection of 100% of the VHP nozzles and undertaking NDE of those nozzles that have indications of cracking,
  - Characterizing any cracks that are identified in VHP nozzles,
  - Operating at a lower RCS hot leg temperature to reduce the head temperature effects on crack initiation and growth,
  - Maximizing the availability of the plant's redundant critical safety systems until shutdown, and
  - Providing increased human factors reliability through additional training, personnel, etc.

RISK ASSESSMENTS*

	Base Scenario	Alternate Scenario**
IE Freq. (/ry)	4.0E-02	2.0E-02
CCDP (/ry)	2.7E-03	2.0E-03
Delta CDF (/ry)	1E-04	4E-05
LERF (/ry)	1E-06	4E-07
Delta CDF (12/31/01)(/ry)	1E-05	3E-06
Delta CDF (3/31/02)(/ry)	4E-05	
Delta CDF (2/16/02)(/ry)		8E-06

*Risk numbers are approximate due to the various uncertainties associated with this issue.

**Includes some credit for past inspections, compensatory actions to reduce CCDP, and shortened duration of operation

RISK-INFORMED DECISIONMAKING GUIDELINES

- RG 1.174
  - Intended for licensing basis changes (permanent changes)
    - ΔCDF less than 1E-06/ry: very small changes are allowed with tracking of cumulative inpacts on CDF
    - ΔCDF between 1E-06/ry and 1E-05/ry: small changes are allowed with tracking of cumulative impacts on CDF
    - ΔCDF>1E-05/ry are not normally allowed
- RG 1.182
  - Intended for managing risk associated with maintenance activities (short-duration)
    - ICDP<1E-06 and ILERP 1E-07: normal work controls apply
    - ICDP between 1E-06 and 1E-05 or ILERP between 1E-07 and 1E-06
      - Assess non-quantifiable factors
      - Establish risk management actions
    - ICDP>1E-05 or ILERP>1E-06
      - Configuration should not normally be entered voluntarily

RG 1.174 SAFETY PRINCIPLES

- Current Regulations are met
  - It is likely that, if inspections were performed today, the current regulations would not be met (TS requirements and GDC)
- Defense-in-depth philosophy is maintained
  - It is likely that one of 3 barriers is degraded
  - However, Davis-Besse has a large, dry containment (licensee states that conditional containment failure probability is1.5E-03)
- Sufficient safety margins are maintained
  - It is likely that safety margins are reduced
- Only a small increase in CDF results
  - ΔCDF (assuming operation until 2/16/02 and crediting comp. actions) is approximately 8E-06/ry
  - Baseline CDF is 6.6E- 05/ry (IPE)
- The basis of risk measurement is monitored using performance measurement strategies
  - Will not occur until inspection is performed