May 9, 2003

Mr. Lew W. Myers
Chief Operating Officer
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 INTEGRATED INSPECTION REPORT 50-346/03-04

Dear Mr. Myers:

On March 31, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Davis-Besse Nuclear Power Station. The enclosed inspection report documents the inspection findings which were discussed on March 28, 2003, 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. For the entire inspection period, the Davis-Besse Nuclear Power Station was under the Inspection Manual Chapter (IMC) 0350 Process. The Davis-Besse Oversight Panel assessed inspection findings and other performance data to determine the required level and focus of followup inspection activities and any other appropriate regulatory actions. Even though the Reactor Oversight Process had been suspended at the Davis-Besse Nuclear Power Station, it was used as guidance for inspection activities and to assess findings.

In addition to documenting the results of the inspection activities conducted by inspectors at Davis-Besse during this time period, this integrated resident inspection report will be used to document the closure of several Davis-Besse Restart Checklist Items. The Davis-Besse Oversight Panel has reviewed and discussed the items and determined that they could be closed. Specifically, Checklist Items 1.a, 6a, 6,b, 6c, 6d, 6e, and 6f, were closed in this report, as documented in Section 4OA5.

Based on the results of this inspection, the inspectors identified one finding of very low safety significance (Green) that was determined to involve a violation of NRC requirements. The finding did not present an immediate safety concern. However, because of the very low safety significance of the finding, and because it was entered into your corrective action program, the NRC is treating the finding as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC Enforcement Policy. If you contest the subject or severity of the Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with a copies to the Regional Administrator Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington DC 20555-001; and the NRC Resident Inspector at Davis-Besse.

Since the terrorist attacks on September 11, 2001, the NRC has issued two Orders (dated February 25, 2002, and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The NRC also issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25th Order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year (CY) ‘02, and the remaining inspections are scheduled for completion in CY ‘03. Additionally, table-top security drills were conducted at several licensees to evaluate the impact of expanded adversary characteristics and the ICMs on licensee protection and mitigation strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Security and Incident Response. For CY ‘03, the NRC will continue to monitor overall safeguards and security controls, conduct inspections, and resume force-on-force exercises at selected power plants. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

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/reading-rm/adams.html(the Public Electronic Reading Room).

Sincerely,

/RA/

John A. Grobe, Chairman
Davis-Besse Oversight Panel

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

Enclosure: Inspection Report 50-346/03-04

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-346
License No:	NPF-3
Report No:	50-346/03-04
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 North State Route 2 Oak Harbor, OH 43449-9760
Dates:	February 9, 2003, to March 31, 2003
Inspectors:	S. Thomas, Senior Resident Inspector D. Simpkins, Resident Inspector R. Powell, Senior Resident Inspector (Perry) D. Schrum, Reactor Inspector
Contributors:	J. Hopkins, Project Manager, NRR A. Hiser, Senior Mechanical Engineer, NRR
Approved by:	Christine A. Lipa, Chief Branch 4 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000346/2003-004; 2/9/2003 - 3/31/2003; Davis-Besse Nuclear Power Station. Resident Inspection Report.

This report covers a 7-week period of resident inspection. The inspection was conducted by resident and Region III inspectors. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609 “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be “Green” or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

Green. The inspectors identified a non-cited violation of Technical Specification 6.8.1.a, which resulted in the failure of the CAC 2 service water PVC jumper. This failure was a direct result of the licensee not properly controlling the installation of the Poly-vinyl Chloride (PVC) jumper in accordance with the requirements of their “Control of Temporary Modifications” procedure.

The inspectors determined that the finding is more than minor because it: (1) involves the configuration control attribute of the Initiating Events cornerstone; and (2) affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. Since the performance issue did not directly affect Core Heat Removal, Inventory Control, Power Availability, Containment Control, or Reactivity Control, the issue was considered to be of very low safety significance. (4OA5.1(C))

REPORT DETAILS

Summary of Plant Status

The plant was shutdown on February 16, 2002 for a refueling outage. During scheduled inspections of the control rod drive mechanism nozzles, significant degradation of the reactor vessel head was discovered. As a direct result of the need to resolve many issues surrounding the Davis-Besse reactor vessel head degradation, NRC management decided to implement IMC 0350, "Oversight of Operating Reactor Facilities in a Shutdown Condition With Performance Problems." The fuel was removed from the reactor on June 26, 2002, and the plant remained shut down. The plant entered Mode 6 on February 19, 2003, and fuel reload was completed on February 26, 2003. For the entire inspection period, the Davis-Besse Nuclear Power Station was under the IMC 0350 Process. As part of this Process, several additional team inspections continued. The subjects of these inspections included: System Health Assurance, Management and Human Performance, and Program Compliance. The status of these inspections will not be included as part of this inspection report, but upon completion, each will be documented in a separate inspection report which will be made publicly available on the NRC website.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity.

1R04 Equipment Alignment (71111.04Q)

a. Inspection Scope

The inspectors verified equipment alignment for accessible portions of the component cooling water system Train 1 concurrent with entry into Mode 6 on February 19, 2003 and identified any discrepancies that impacted the function of the system's components or increased in plant risk. The inspectors also verified that the licensee had properly identified and resolved any equipment alignment problems that would cause initiating events or impact the availability and functional capability of this mitigating system. Specific aspects of this inspection included reviewing plant procedures, drawings, and the Updated Safety Analysis Report (USAR), to determine the correct system lineup and evaluating any outstanding maintenance work requests on the system or any deficiencies that would affect the ability of the system to perform its function. A majority of the inspector's time was spent performing a walkdown inspection of the system. Key aspects of the walkdown inspection included:

- valves were correctly positioned and did not exhibit leakage that would impact their function;
- electrical power was available as required;
- major system components were correctly labeled, lubricated, cooled, ventilated, etc.;
- hangers and supports were correctly installed and functional;
- essential support systems were operational;

- ancillary equipment or debris did not interfere with system performance;
- tagging clearances were appropriate; and
- valves were locked as required by the licensee's locked valve program.

During the walkdown, the inspectors also observed the material condition of the equipment to verify that there were no significant conditions not already in the licensee's work control system.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of fire fighting equipment, the control of transient combustibles, and on the condition and operating status of installed fire barriers. The inspectors selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events, their potential to impact equipment which could initiate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed at the end of this report, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use, that fire detectors and sprinklers were unobstructed, that transient material loading was within the analyzed limits, and that fire doors, dampers, and penetration seals appeared to be in satisfactory condition.

The following areas were inspected:

- emergency diesel generator room 1; and
- emergency diesel generator room 2.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the Maintenance Rule requirements to verify that the systems identified as (a)(1) had appropriate goals established, including a performance based monitoring period, and corrective actions to correct the defective condition. To evaluate the effectiveness of (a)(1) activities, the inspectors reviewed (a)(1) action plans, work orders, and CRs. This inspection was performed to ensure that, as the licensee progressed through their restart plan, focus placed on correcting identified Maintenance Rule issues was appropriate.

b. <u>Findings</u>

No findings of significance were identified.

1R13 <u>Maintenance Risk Assessment and Emergent Work Evaluation (71111.13)</u>

a. Inspection Scope

The inspectors reviewed the licensee's response to risk significant activities. These activities were chosen based on the potential impact on overall plant risk or their impact on core cooling. The inspection was conducted to verify that the evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and minimize the duration where practical, and that contingency plans were in place where appropriate. The licensee's daily configuration risk assessments, observations of shift turnover meetings, observations of daily plant status meetings, and the documents listed at the end of this report were used by the inspectors to verify that the equipment configurations had been properly listed, that protected equipment had been identified and was being controlled where appropriate, and that significant aspects of plant risk were being communicated to the necessary personnel. The following risk significant evolutions were evaluated by the inspectors:

- core alterations conducted the week of February 17, 2003;
- reactor coolant pump work conducted during March, 2003; and
- initial reactor coolant system deep drain conducted on March 11, 2003.

b. <u>Findings</u>

No findings of significance were identified.

1R14 <u>Performance in Non-Routine Evolutions (71111.14)</u>

a. <u>Inspection Scope</u>

The inspectors observed operations personnel to verify personnel performance was conducted in a safe and conservative manner during the following activities:

- reactor fuel reload activities; and
- reactor coolant system deep drain conducted to support steam generator nozzle dam removal and steam generator manway replacement.

The inspectors reviewed Technical Specifications (TS), operations procedures, and facility administrative procedures to determine the acceptance criteria for the inspection.

b. <u>Findings</u>

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors selected Condition Reports (CRs) which discussed potential operability issues for risk significant components or systems. These CRs were evaluated to determine whether the operability of the components or systems was justified. The inspectors compared the operability and design criteria in the appropriate sections of the Technical Specifications and USAR to the licensee's evaluations presented on the issues listed below to verify that the components or systems were operable. Where compensatory measures were necessary to maintain operability, the inspectors verified that the measures were in place, would work as intended, and were properly controlled.

The issues evaluated were:

- emergency diesel generator 1 voltage and frequency dropped below USAR design criteria during automatic load sequencing on February 3, 2003 (operability evaluation addressed modes 5 and 6 only); and
- emergency diesel generator 1 operability given common cause failure concern associated with fouling of the emergency diesel generator 2 air inlet filter on February 17, 2003.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Decay Heat Pump Testing Subsequent to Rebuild of System Components

a. Inspection Scope

The inspectors reviewed post-maintenance testing activities associated with Decay Heat Pump 2, subsequent to the rebuild of system components, to ensure that the testing adequately verified system operability and functional capability with consideration of the actual maintenance performed. The inspectors used the appropriate sections of the TSs and the USAR, as well as the documents listed at the end of this report, to evaluate the scope of the maintenance and verify that the work control documents required sufficient post-maintenance testing to adequately demonstrate that the maintenance was successful and that operability was restored. In addition, the inspectors reviewed CRs to verify minor deficiencies identified during these inspections were entered into the licensee's corrective action system.

b. Findings

No findings of significance were identified.

.2 High Pressure Injection Pump 1

a. Inspection Scope

On March 5, 2003, two internal fasteners were discovered missing upon inspection of the suction piping to the high pressure injection pump 1. One of the fasteners was found wedged between the shaft and the first stage impeller. After extensive inspection of the pump, upstream piping, and the downstream piping, the second fastener was not located. The high pressure injection pump was removed from the system and transported to an off-site repair facility for further analysis and repair. No damage was noted internal to the pump which indicated that the second fastener had not passed through the pump.

While the pump was at the repair facility being repaired, the plant transitioned to operating Mode 5. Since the refueling canal was drained and the reactor head was installed on the reactor and tensioned, the plant conditions that supported the normal surveillance procedure used to verify high pressure pump operability could not be established for retesting the pump upon its return. The inspectors evaluated the licensee alternative testing methods proposed to satisfy the restest requirements for the repaired pump.

b. Findings

At the time this report was prepared, the high pressure injection pump had not been returned from the repair facility. Additional issues had been identified which involved the pump's hydrostatic bearing (Section 4OA5.2). The pump remained at the repair facility pending resolution of the bearing issue. The inspectors did not identify any significant issues with the alternative testing methods for the high pressure injection pumps that were proposed by the licensee**.**

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors witnessed several surveillance tests and evaluated test data to verify that the equipment tested met TSs, USAR, and licensee procedural requirements, and also demonstrated that the equipment was capable of performing its intended safety functions. The activity was selected based on its importance in verifying mitigating system capability. The inspectors used the documents listed at the end of this report to verify that the test met the TS frequency requirements; that the test was conducted in accordance with the procedures, including establishing the proper plant conditions and prerequisites; that the test acceptance criteria were met; and that the results of the test were properly reviewed and recorded.

The following tests were observed and evaluated:

- safety features actuation system channel 2 test;
- high pressure injection pump comprehensive and check valve forward flow test for Train 1;
- station blackout diesel generator dead bus load test; and
- emergency diesel generator 2 184 day test.

b. Findings

With the exception of the high pressure injection pump comprehensive and check valve forward flow test for Train 1, no findings of significance were identified. The high pressure injection pump did not meet the acceptance criteria documented in the surveillance procedure. Subsequent troubleshooting revealed foreign material internal to the pump. This issue was discussed further in section 1R19 of this report.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed temporary modification 03-005, "Structure South Ventilation Penthouse," to verify that the modification did not affect the safety functions of risk significant safety systems. This temporary modification was put in place to maintain service water pump room temperature greater than 40 degrees Fahrenheit during periods of time when outside temperatures dropped below 20 degrees Fahrenheit. The inspectors reviewed the temporary modification and associated 10 CFR 50.59 screenings against system requirements, including the USAR and TS to determine if there were any effects on system operability or availability and to verify temporary modification consistency with plant documentation and procedures.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA2 Identification and Resolution of Problems (71152)

.1 (Closed) Unresolved Item (URI) 50-346/00-07-05 (DRS): Review of Licensee's Documentation for Elimination of Fire Barrier Wrap in Component Cooling Water (CCW) Pump Room.

The inspectors identified this URI during a CCW Pump Room walkdown, when the inspectors noted that the three CCW pumps did not meet the Appendix R separation requirements of 20 feet, and that none of the components or circuits had fire protection barriers. The licensee stated that modifications and re-analysis had eliminated the need for protection of any conduits in the CCW pump room; however, they were unable to provide the evaluations needed to support this statement. Without a review, it was not obvious that the current configuration of the CCW Room would be approved even with an amended exemption. This was considered an Unresolved Item until the licensee's evaluations, eliminating the need for fire wraps/barriers within the CCW pump room, could be evaluated. In addition to these barrier issues, NCV 50-346/00-07-04 was issued for no longer meeting Appendix R requirements as identified in an NRC Exemption issued on November 23, 1982. The licensee entered these issues into their corrective action system as CR 2000-1857.

On December 21, 2000, as supplemented by letter dated March 21, 2001, the licensee submitted a request to amend the existing exemption from 10 CFR Part 50, Appendix R, for the CCW heat exchanger and pump room and requested a revision to the exemption to eliminate the requirement for one hour fire barriers (fire wrap) on Safe Shutdown (SSD) cables and valves in the CCW pump room. Several re-evaluations and plant modifications had been performed to eliminate the need for this fire wrap.

The commission approved exemption "Davis-Besse Nuclear Power Station, Unit 1, Exemption From The Requirements of 10 CFR Part 50, Section III. G. of Appendix R (TAC No. MB1078), dated December 26, 2002," from the specific requirements of 10 CFR Part 50, Section III.G. of Appendix R.

The failure to provide information on plant modifications and re-analysis during the inspection was the bases of the URI. The licensee provided this information to NRR to obtain the new Appendix R Exemption. The exemption resolves the concerns with this issue. In addition, because a NCV was previously identified for this issue, no additional enforcement is necessary. This URI is closed.

4OA5 Other Activities

One of the key building blocks in the licensee's Return to Service Plan was the Management and Human Performance Excellence Plan. The purpose of this plan was to address the fact that "management ineffectively implemented processes, and thus failed to detect and address plant problems as opportunities arose." The primary management contributors to this failure were grouped into the following areas:

- Nuclear Safety Culture;
- Management/Personnel Development;
- Standards and Decision-Making;
- Oversight and Assessments;
- Program/Corrective Action/Procedure Compliance.

The inspectors had the opportunity to observe the day-to-day implementation that the licensee made toward completing Return to Service Plan activities. Almost every inspection activity performed by the resident inspectors touched upon one of those five areas. Observations made by the resident inspectors were routinely discussed with the Davis-Besse Oversight Panel members and were used, in part, to gauge licensee efforts to improve their performance in these areas on a day-to-day basis.

To better facilitate the inspection and documentation of issues not specifically covered by existing inspection procedures, but important to the evaluation of the licensee's readiness for restart, the Special Inspection for Residents inspection plan was developed and implemented. Inspection Procedure 93812, "Special Inspection," was used as a guideline to document these issues and remains in effect for future resident inspection reports until a time to be determined by the Davis-Besse Oversight Panel. The inspectors performed inspections, as required, to adequately assess licensee performance and readiness for restart in the following area:

- performance of plant activities, including maintenance activities;
- follow-up of specific Oversight Panel technical issues;
- conduct of licensee restart readiness meetings;
- evaluation of licensee performance in categorizing, classifying, and correcting deficient plant conditions during the restart process;
- licensee controls and criteria associated with work backlogs, including assessing licensee performance at meetings discussing work control and the deferral of work orders, operator workarounds, temporary modifications, and permanent modifications; and
- activities associated with safety conscious work environment and safety culture.

The following issues were evaluated during this inspection period.

.1 Performance of Plant Activities, Including Maintenance Activities

A. Makeup Pump 2 High Thrust Bearing Temperature

On January 27, 2002, the mechanical seals were replaced on makeup pump 2. Post maintenance testing was not performed on the pump because plant conditions did not support the required testing nor was the pump required to be operable to support existing plant conditions. On February 23, 2003, makeup pump 2 was started in preparation for the Integrated Safety Features Actuation System test. During the initial run of the pump, increasing thrust bearing temperatures were observed which caused the pump to be manually secured after approximately 10 minutes. Troubleshooting efforts revealed no bearing damage and no definitive cause of the high temperature indication. A new thrust bearing was installed, the pump was retested, and the thrust bearing high temperature condition did not return.

Through the evaluation of the licensee's mechanical maintenance problem solving plan, the inspectors learned that a similar condition had occurred on makeup Pump 1, approximately 3 years earlier, following the replacement of its mechanical seals. At that time, a vendor representative from the thrust bearing manufacturer had determined that the cause of the high thrust bearing oil temperatures was that the thrust bearing shoes had not been reassembled exactly as original installation during pump reassembly and that the thrust bearing's "geometry" had been compromised. In this application of the thrust bearing, the geometry between the thrust collar and the thrust bearing shoes is critical and is extremely difficult to recreate following disassembly in the field. Subsequent to the installation of a new thrust bearing and post maintenance testing of the pump, no further indications of high thrust bearing oil temperature were observed.

The inspectors questioned the practice of reassembling the thrust bearings in the field during makeup pump reassembly, after mechanical seal replacement, and why the practice continued after the cause of the 1999/2000 problem had been diagnosed by the bearing vendor representative as improper bearing "geometry" probably caused during bearing reassembly. In response, the Nuclear Mechanical Maintenance Superintendent informed the inspectors that the makeup pump maintenance procedure would be revised with instructions to install a new thrust bearing any time maintenance was performed on the makeup pump which required disassembly of the thrust bearing.

Since makeup Pump 2 was already inoperable when the high thrust bearing oil issue was identified and was not required to support the plant configuration that existed at the time, the issue's impact on plant risk was negligible. This example illustrated a potential weakness in the use of operating experience by maintenance to reduce rework on risk significant components. The recent thrust bearing oil high temperature issue was entered into the licensee's corrective action program as CR 03-01494. At the time of this report, the makeup pump maintenance procedure had not been revised to include the new thrust bearing instructions, nor had a corrective action been assigned to the CR to facilitate that change.

B. Containment Air Cooler (CAC) 1 Service Water Tree Installation

The containment air coolers were three of the many components that were directly impacted and suffered varying degrees of degradation as a result of corrosion by boric acid. The licensee made the decision to completely rebuild each of the CACs to better than new condition. This was accomplished, in part, by obtaining all new cooling coils constructed of significantly more robust materials than the original cooling coils. The new cooling coils were constructed of heavier, more rigid, materials. This introduced significant engineering challenges in developing a piping design that attached the new cooling coils to the existing service water system and still provided sufficient design margin which ensured that the service water piping remained connected to the CACs during accident conditions. The solution was two service water "trees" per CAC, with expansion bellows located at each of the cooling coil's outlet. These bellows allowed for some movement between the CAC and the service water piping.

During the installation of the service water trees for CAC 1, many problems were identified. These problems included:

- fins on installed cooling coils were bent or damaged due to ongoing work activities;
- workers were observed using the service water tree piping as a ladder to access upper portions of the service water tree;
- installation difficulties caused several bellows to have offsets, between the inlet and the outlet, greater than allowed by the manufacturer; and
- weld dams were not removed prior to attempting to restore service water to CAC 1.

The CAC 1 service water tree post installation inspection revealed the following deficiencies with the expansion bellows:

- four bellows were dented;
- one bellows was cut with a grinder;
- one bellows had a welding arc strike; and
- three bellows were misaligned beyond the vendor's recommendation.

The first attempt to restore service water to CAC 1 revealed leaks on two expansion bellows and a leak at one of the gaskets on a cooling coil end plate flange. The two bellows were replaced and after attempts to tighten header box bolts failed to stop the cooling coil leak, that one cooling coil was taken out of service by installing blind flanges in the service water supply and return lines for that cooling coil. An assessment of the as-installed condition of CAC 1 bellows to support availability of the CAC for draining the reactor coolant system to less than 23 feet was obtained by the licensee. This assessment supported availability, providing that an in-service leak test at service water system operating pressures be performed and examination of the dents in the bellows be performed to verify no surface cracking had occurred. This assessment also stated that, "Although the leaking bellows have been replaced, there is no way to determine what conditions the remaining bellows installed on CAC 1 have been subjected to. All installed bellows should be replaced to assure operability of CAC 1 to support the transition to Plant Operating Mode 3."

The licensee has taken some visible corrective actions to prevent future damage to the CACs as evidenced by protective wrappings on the CAC 1 expansion bellows and protective blankets which covered the cooling coils on all three CACs. The lessons learned from problems encountered during installation of the service water trees on CAC 1 were incorporated into the installation work control documents so that the same errors were not repeated during the installation of the service water trees for CAC 2 and CAC 3. Also, Director level oversight and greater Service Water System Engineer involvement on the project has improved the quality of work on CAC 2 and CAC 3. The inspectors were initially informed by the Director of Nuclear Engineering that all of the expansion bellows on CAC 1 would be replaced prior to transitioning to an operational mode that required CAC operability. Further engineering evaluation determined that only 7 of the 12 expansion bellows on CAC 1 needed to be replaced.

This issue illustrated examples of inattention to detail, poor work practices, poor workmanship, and poor engineering oversight at the jobsite. Since CAC 1 was not required to be operational to support the plant configuration at the time, the risk impact of this issue was negligible. This issue was entered into the licensee corrective action program through a number of CRs which included CR 03-1745, CR 03-1519, CR 03-1512, CR 03-1674, CR 03-1741, CR 03-1708, CR 03-1777.

C. CAC 2 Service Water Jumper Failure

Introduction. A Green NRC identified NCV was identified for the failure to properly implement procedures required by Technical Specification 6.8.1.a to control the installation of PVC jumper located in the service water system.

Description. On March 8, 2003, during a flush of the CAC 2 service water piping following hydrolazing, the PVC test jumper which connected the CAC 2 service water inlet and outlet piping failed catastrophically. As a result of the failure, approximately 3000-4000 gallons of service water spilled into containment. Although the introduction of this water produced some spread of contamination and water processing challenges, there was no significant impact to safety-related equipment. The failure of this jumper appears to have been caused by a number of factors:

- field modification of the PVC jumper was performed (from what was originally called for by the system engineer), which reduced the overall strength of the jumper;
- a metal strap was added above the U portion of the jumper which further weakened the jumper by placing the failed portion of the jumper in tension;
- colder service water caused the PVC to be more brittle;
- questionable mechanical practices were used to clear obstructions in the jumper flush line;
- lack of physical support for the jumper assembly; and
- at the end of the flush, the service water discharge valve supporting the flush was closed first, instead of the service water inlet valve, which resulted in a system pressure surge.

One of the stated purposes of the "Control of Temporary Modifications" procedure is to "control temporary modifications only on structures, systems, or components which will be placed in service with the temporary modification installed." The procedure further defined In-Service as "equipment and systems are in-service when they are lined up in accordance with system procedures and are operating or ready to operate." Additionally, a mechanical jumper, which was listed as an example of a temporary modification by the procedure, was defined as "a mechanical connection such as piping that separates or joins two systems or bypasses a component within a system, thus altering the system's design or configuration." The purpose of the installed jumper was to bypass CAC 2 while the service water piping that normally supplied the CAC was being flushed.

The actual fabrication and installation of the jumper was not treated as a temporary modification and was accomplished by a work order. The jumper was designed by the service water system engineer to handle full service water system pressure and a sketch which annotated pipe size and material was provided as part of the work package. This sketch was intended to be used to construct the PVC jumper that was installed for the CAC 2 service water flush. When the field installation of the jumper could not be installed as designed, work planners, with minimal engineering concurrence, annotated the jumper sketch with a note which stated "modify PVC piping and fittings to facilitate installation." The final jumper that was fabricated and installed was structurally weaker than was originally designed by the system engineer and subsequently failed near the end of the CAC 2 service water piping flush.

The inspectors identified that the failure of the CAC 2 service water PVC jumper was a direct result of the licensee not properly controlling the installation of the PVC jumper in accordance with the requirement of their "Control of Temporary Modifications" procedure.

Analysis. The inspectors determined that not implementing the appropriate controls for the fabrication and installation of the service water jumper, and the ultimate failure of the jumper, was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports, Appendix B, "Issue Disposition Screening," issued on April 29. 2002. The inspectors determined that the finding was more than minor because it: (1) involved the configuration control attribute of the Initiating Events cornerstone; and (2) affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations.

The inspectors evaluated the significance of the findings using IMC 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process." Specifically, they reviewed the section "PWR Refueling Operation RCS Level Greater than 23 feet and evaluated the issue impact on the following attributes; Core Heat Removal, Inventory Control, Power Availability, Containment Control, Reactivity Control. Since the performance issue did not directly affect any of these attributes, a Phase 2 analysis was not required and the issue was considered to be of very low safety significance.

Enforcement. The performance deficiency associated with this event was the failure to implement procedures appropriate to the circumstances. Technical Specification 6.8 required written procedures to be implemented covering applicable procedures recommended by Regulatory Guide 1.33. Regulatory Guide 1.33 recommended procedures for performing maintenance which can affect the performance of safety-related equipment. By not implementing the Control of Temporary Modifications procedure, inadequate controls were in place to control the fabrication and installation of a PVC jumper in the service water system. This activity was an integral part of the maintenance activity. As such, in accordance with Regulatory Guide 1.33, Appendix A, Section 1, Administrative Procedures, the activity should have been performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. The inspectors concluded that the licensee did not implement procedure NG-EN-00313, Control of Temporary Modifications, Revision 3, as required during the installation of the service water jumper for CAC 2, which significantly contributed to the failure of the jumper while the service water train was in service. Because this issue is of very low safety significance and has been entered into the licensee's corrective action program (CR 03-01888), this violation is being treated as a NCV, consistent with Section VI.A.1 of the USNRC Enforcement Policy (NCV 50-346/03-04-01).

.2 Follow-Up of Specific Oversight Panel Technical Issues

High Pressure Injection Pump Repair/Replacement

During the recirculation phase of some accident scenarios, water that was collected in the emergency sump would be pumped from that sump to the suction of the high pressure injections pumps, via the low pressure injections pumps. On October 22, 2002, the licensee identified that during this pumping configuration, the potential existed for the cooling water flow to the hydrostatic bearings in the high pressure injection pumps to be blocked.

The new emergency sump strainer design allowed pieces of material which measured up to .1875 inches to pass through the strainer. Under the configuration described above, this material would then pass through the low pressure injection pump and be discharged to the suction of the high pressure injection pump. The hydrostatic bearing utilized by the high pressure injection pumps at Davis-Besse had a very tight radial clearance of .0059 inches. These bearings were lubricated by the water being pumped, via .25 inch ports which tapped off the high pressure injection pump's fourth stage. Any material that was small enough to pass through the fourth stage ports, but too large to pass through the hydrostatic bearing, would collect and eventually block lubrication flow to the bearing. Once the fluid film present at the shaft/bearing interface was inadequate, the potential for rapid failure and seizure of the rotating element existed.

The overall impact and the corrective action for this issue was still under evaluation at the time that this report was submitted. This issue had negligible impact on plant risk since the high pressure injection pumps were not required to support the current plant configuration. This issue has been documented in the licensee corrective action program as CR 02-8492.

.3 <u>Classification, Categorization, and Resolution of Restart Related Issues</u>

The resident inspectors continued to monitor the licensee activity related to properly classifying, categorizing and resolving their backlog of work orders, corrective actions, and modifications required to be completed prior to transitioning to Mode 5 and 4. To accomplish this, the inspectors:

- attended and assessed licensee management meetings;
- monitored the management of open Mode 5 and 4 restraints;
- evaluated the licensee classification of emergent deficient conditions; and
- evaluated closed mode restraints.

As part of this inspection, the inspectors attended selected Mode Change Readiness Review meetings, Senior Management Team meetings, Management Review Board meetings, and Restart Station Review Board meetings where classification of CRs, prioritization of work activities, and setting of work completion dates took place. Specific items noted by the inspectors during these meetings included:

- a large number of issues that originally were classified as Significant Conditions Adverse to Quality (SCAQ), were downgraded to Conditions Adverse to Quality (CAQ);
- approximately 17 percent of the Design Engineering issues discussed at a Mode Change Readiness Review meeting and approximately 33 percent of the Plant Engineer issues discussed at another Mode Change Readiness Review meeting had work completion dates moved up to align the completion of the work activities with current milestone schedule; and

- Some “rolling” up of multiple CRs and corrective actions into single CRs was noted.

The inspectors evaluated a sampling of CR downgrade documentation forms associated with the SCAQs that were downgraded to CAQs and a sampling of CRs that resulted from the “rolling” up process. No significant issues were identified by the inspectors. The process of adjusting work activity completion dates so that milestone dates were met, alone was not an issue. The inspectors continued to evaluate, on a day-to-day basis, the impact that scheduling had on quality of work and safety conscious work environment. No significant issues were identified.

.4 Safety Conscious Work Environment and Safety Culture Observations

The inspectors attended a number of meetings where the licensee discussed their current assessment of safety culture at Davis-Besse. The licensee assessment was performed in accordance with DBBP-VP-0002, “Restart Readiness Review Extended Plant Outage,” Revision 02. Attachment 8 of this procedure specifically dealt with the assessment of safety culture. Safety culture was assessed in three broad categories: Policy or Corporate Commitment Area (which contained 5 subsections), Plant Management Commitment Area (which contained 7 subsections), and Individual Commitment Area (which contained 5 subsections). The process involved discussion of each subsection topic by the Davis-Besse management team with the result being a color assignment for each subsection attribute. After all the subsections for each of the three broad categories had been assessed, each of the three broad categories were given a color.

The safety culture commitment area rating was designated by color and was defined as follows:

- Green all major areas are acceptable with few minor indicator deviations
- White: all major areas are acceptable with a few indicators requiring management attention
- Yellow: all major areas are acceptable with several indicators requiring prompt management action
- Red: several major areas do not meet acceptable standards and require immediate management action

The ratings assigned to the three broad categories based on the assessment that concluded on March 18, 2003, were:

- Policy or Corporate Commitment: Yellow
- Plant Management Commitment: Yellow
- Individual Commitment: Yellow

The inspectors were able to observe several hours of this process, which spanned several days. During that time, the inspectors noted good probing discussions of each attribute by the Davis-Besse managers. Additionally, the inspectors verified that significant issues identified during these meetings were documented in CRs and entered into the licensee corrective action program.

.5 Closure of Restart Checklist Items

The Davis-Besse Oversight Panel (0350 Panel) met to review the following Restart Checklist Items and approved their closure:

- Checklist Item 1.a

  Attachment 1 to this inspection report contains the Office of Nuclear Reactor Regulation's assessment of the licensee's root cause analysis. This closes restart checklist item 1.a.

- Checklist Item 6.a

  By letter dated August 9, 2002 (Serial No. 1-1281), the licensee stated that relief requests A8 and A12 regarding the shell to flange weld, which were previously submitted to the NRC, were not impacted by the new reactor pressure vessel (RPV) head. The staff completed its review of the relief requests and approved them by letter dated September 30, 2002 (ADAMS accession No. ML022700279).

- Checklist Items 6.b and 6.c

  The licensee submitted relief request (RR) A26 for failure to maintain original radiographic tests of the new RPV head to flange weld and RR A27 for inability to radiographically test 100 percent of the new RPV head to flange weld by letter dated August 1, 2002 (Serial No. 2797) as supplemented by letter dated September 23, 2002 (Serial No. 2809). The NRC staff reviewed the requests and approved them by letter dated December 13, 2002 (ADAMS Accession No. ML022830831).

- Checklist Item 6.d

  The licensee submitted relief request A2 for inability to perform 100 percent volumetric and surface examination of new RPV head to flange weld by letter dated August 1, 2002 (Serial No. 2798). The staff reviewed the request and approved it by letter dated December 17, 2002 (ADAMS Accession No. ML023050104).

- Checklist Item 6.e

  The licensee's letter of August 9, 2002 (Serial No. 1-1281), also provided information regarding the reconciliation of the new RPV head with American Society of Mechanical Engineers (ASME) Code requirements. The NRC staff reviewed the information provided and determined that it was satisfactory. NRC Inspection Report 50-346/02-07 (DRS) dated November 29, 2002 (ADAMS

Accession No. ML023370100), discusses the head complying with ASME requirements.

- Checklist Item 6.f

  By letter dated January 22, 2003 (serial no. 1-1285), the licensee submitted verification that the pressure/temperature curves in the TS are applicable to the new RPV head. The NRC staff has reviewed the submittal and has determined that the information provided is satisfactory.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. Lew Myers, Chief Operating Officer, FirstEnergy Nuclear Operating Company, and other members of licensee management on March 28, 2003. The licensee acknowledged the findings presented. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Closure of URI 50-346/00-07-05 with Mr. R. Fast on March 13, 2003.

Attachment 1

DAVIS-BESSE NUCLEAR POWER STATION

DEGRADATION OF REACTOR PRESSURE VESSEL HEAD

TECHNICAL SEQUENCE OF EVENTS

DOCKET NO. 50-346

OFFICE OF NUCLEAR REACTOR REGULATION

1.0 INTRODUCTION

By letter dated April 18, 2002 (ADAMS Accession No. ML021130029), FirstEnergy Nuclear Operating Company (FENOC) submitted its Root Cause Analysis Report of the reactor pressure vessel (RPV) head degradation in accordance with the Confirmatory Action Letter dated March 13, 2002. On May 7, 2002, the Nuclear Regulatory Commission (NRC) staff held a public meeting with FENOC representatives to discuss the technical aspects of the root cause analysis. Revision 1 of the Report was submitted by letter dated September 23, 2002 (ADAMS Accession No. ML022750125).

The Davis-Besse Root Cause Analysis Report provides a broad scope assessment of the "root cause," covering various programmatic, implementation and managerial issues, along with a description of the technical sequence of events from the initiation of cracking in the control rod drive mechanism (CRDM) nozzles to the formation of the cavity identified in March 2002. The NRC staff review below focuses on the technical sequence of events, including the plausibility of the licensee's hypotheses, implications for Davis-Besse restart, and generic implications. Also, the staff review considers the Davis-Besse experience in context with findings from other plants, along with additional consideration of factors discounted by the licensee.

2.0 BACKGROUND

The licensee concluded that the degradation of the RPV head at CRDM Nozzles 2 and 3 was caused by boric acid corrosion as a result of leakage from nozzle cracks, which had formed due to primary water stress corrosion cracking (PWSCC). The licensee described the root cause as a 'probable root cause' because of the paucity of direct physical evidence to support the licensee's hypotheses.

The licensee described the degradation sequence as having four stages: Stage 1 - crack initiation and progression; Stage 2 -minor weepage/latency period; Stage 3 - deep annulus corrosive attack; and Stage 4 - general boric acid corrosion. Further details on the licensee's hypothesis of these four stages are presented below.

Stage 1 - Crack initiation and growth to through wall: The report postulates that a crack initiated in Nozzle 3 around 1990 (±3 years) due to PWSCC. The crack grew to through-wall and penetrated the wall thickness above the J-groove weld in the 1994 to 1996 time period. At this stage, the report hypothesizes that the extent of through-wall cracking was very limited and the reactor coolant system (RCS) leakage would have been extremely small.

Stage 2 - Minor weepage/latency period: As the crack grew, leakage would have entered the annular region between the Alloy 600 nozzle and low-alloy steel RPV head. With moist boric acid weeping from the newly developed crack into the bi-metallic annulus, various corrosion and concentration processes, including galvanic attack, are possible. The report proposes that these corrosion processes would open the annular gap; however, the NRC staff believes that it could alternatively be argued that corrosion products and insoluble precipitation products like iron metaborate or nickel iron borate could plug the gap and reduce the leakage to very low levels.

At this stage, a low level of leakage from the annulus could manifest itself as the classic "popcorn" crust of boric acid deposits. However, In contrast to other plants with leaking nozzles, the NRC staff finds that it is possible that the boron deposits on top of the Davis-Besse RPV head (from CRDM flange leakage) acted as an "incubator," wherein leaking borated water would be retained under the deposits. The staff also finds that the boric acid species identified within the annular enclave is speculative; it could have ranged from aqueous, concentrated solutions of boric acid to molten mixtures of boric acid and boric oxide. The staff presumes that the oxygen content of the solution was small, due to the limited access through the annular gap, coupled with the probable egress of superheated steam through the same gap, and an uphill pressure gradient.

As the crack continued to grow, the Root Cause Report posits that the annular gap increased in width, and that because the growth in annulus width occurred over about half of the circumference of the nozzle, the annulus flow area increased faster than the crack flow area. The Root Cause Report does not mention potential plugging of the annulus by corrosion products and insoluble precipitates, thus presuming that the primary flow resistance would have been due to the dimensions of the crack, and not due to any restriction offered by the annulus geometry. Under those conditions, oxygen may have entered the annulus. If that happened, wastage rates would have increased dramatically.

Stage 3 - Deep annulus corrosive attack: In the scenario presented in the Root Cause Report, continued widening of the annular gap would cause the velocity of flow out of the annulus and the differential-pressure to decrease, allowing greater penetration of oxygen and increased corrosion rates. The Root Cause Report suggests that corrosion is likely to be greater in the vicinity of the crack because leakage through the crack would maintain a fresh supply of new reactive oxidizing ions in the boundary layer near the corroding metallic surface.

Stage 4 - Boric acid corrosion: Positing high leakage rates, the annulus would have filled with an increasing amount of moist steam, for the most part (about 80 percent) flashing as it exited. Heat transfer from the surrounding metal would no longer be sufficient to immediately vaporize the portion of leakage that did not flash. The metal surface temperature was reduced due to the cooling effect resulting from the large heat flux required to vaporize the leaking coolant. This cooling effect allowed a greater area to be wetted underneath the accumulation of boron. As the crack grew, and the leak rate from the crack increased, the corroding annulus is presumed to have begun to fill with a saturated boric acid solution. Because the wetted area would have been the result of liquid flow, it would be expected to be predominantly downhill from the nozzle. This would result in high corrosion rates and wastage of RPV head material on the downhill side of the nozzle.

3.0 EVALUATION

Although it is not possible at present to establish the exact progression of mechanisms that led to the observed RPV head wastage, the degradation modes on the two extremes of the overall progression may be described with reasonable confidence. At the extremely small leak rates (~10^{-5} to 10^{-6} gpm), observed in most of the leaking CRDM nozzles identified in the industry, the leaking flow completely vaporizes to steam immediately downstream from the principal flashing location. This results in a dry annulus and no loss of material. The other extreme is associated with the classic boric acid corrosion mechanism caused by liquid boric acid solution concentrated through boiling and fed by oxygen directly available from the ambient atmosphere. It is likely that the extent of the boiling heat transfer associated with the relatively high leak rate of Nozzle 3 was sufficient to cool the head enough to allow liquid solution to cover the walls of the cavity. Relatively high leakage rates from CRDM cracks were necessary at Davis-Besse for such significant corrosion.

The Root Cause Report does not encompass all possibilities, partially because much of the data necessary to support alternate hypotheses simply does not exist. Wastage of low alloy steel in molten boric acid species, or in concentrated, aqueous solutions is not well-described or quantified in the literature, and especially not under the temperature, flow or stirring rates, and concentration of species that may have been present on the Davis-Besse head. The electrochemical potentials of the alloys and aqueous solutions involved are not known. Crack initiation times may have been short, and the stress-corrosion crack growth rate for the Alloy 182 in the J-groove weld and the Alloy 600 in the CRDM nozzles may have been atypically high, due perhaps to the thermo-mechanical processing of these materials. In short, the degree of uncertainty and the number of unknowns regarding the progression of events that led to the development of the cavity at Davis-Besse limits the ability to qualify the technical root cause report beyond “plausible” at this time.

One area that the Davis-Besse Root Cause Report does not adequately reconcile is the disparity of corrosion findings at Nozzles 2 and 3, findings from other plants, and the role of the boron supplied by the leaking CRDM flanges left on the head for many years. Nozzle 3 had a large corrosion cavity, while Nozzle 2 had a much smaller cavity located at about mid-wall of the RPV head. In all cases at other plants, no significant corrosion was identified. The report provides a cursory basis for the corrosion differences, and focuses on the differences in axial crack length above the J-groove weld between Nozzles 2 and 3. The relatively small crack length differences do not seem consistent with the corrosion differences identified at these two nozzles, indicating that some other factor(s) are most likely involved. In addition, the absence of any significant corrosion at other plants with leaking nozzles indicates that there must have been factors at Davis-Besse that promoted the extensive corrosion that occurred.

As described in the Root Cause Report, one unique characteristic of the Davis-Besse RPV head has been the presence of a persistent layer of boron on the top of the head over the last several cycles (since about 1996). Although this layer of boron is apparently unique to Davis-Besse (other plants with leaking nozzles were more effective in removing boron deposits), the Root Cause Report does not highlight the possible role of this entrenched boron layer as significant, but allows that it may have accelerated the corrosion and increased its severity. The report notes that, over time, leakage from the nozzles would have provided a sufficient accumulation of boron irrespective of the prior existing boron from nozzle flange leakage.

Although there are some uncertainties and inconsistencies in the licensee's technical sequence of events that are presumed to have led to the formation of the corrosion cavity at Davis-Besse, the RPV head replacement by the licensee provides assurance that Davis-Besse can successfully and safely restart. Continued safe operation at Davis-Besse will be assured by the effective implementation of programs that both monitor the new RPV head for nozzle cracks and also identify and clean boron deposits from the RPV head as required by Order dated February 11, 2003, that detailed specific inspection methods and frequencies for inspection of the vessel head penetrations and the vessel head.

Although the licensee's analysis is adequate to support a general understanding of what likely transpired to create the large cavity at Davis-Besse, the generic implications of the technical analysis in the Root Cause Report are still important. In particular, as the NRC and the industry work to develop effective inspection regimes (e.g., inspection method, frequency), the rates of corrosion that occur with degraded conditions directly impact the inspection parameters that are required to provide reasonable assurance of compliance with the regulations and adequate protection of the public health and safety. A more complete understanding of the Davis-Besse event would aid in determining the appropriate inspection requirements to account for the uncertainties in the degradation rates. Therefore, it is important for the licensee to thoroughly document the as-found condition of the corrosion area on the Davis-Besse RPV head for use as a reference source of information. This reference information would be suitable for comparison to the results of new laboratory testing which would help us develop an understanding of the types of conditions that could have led to the as-found Davis-Besse RPV head cavity. The licensee is currently engaged in more thoroughly evaluating the Nozzle 3 cavity area and expects to complete its evaluation in April 2003.

4.0 CONCLUSION

Based on the information currently available, the NRC staff concludes that the licensee's analysis presents a plausible scenario of the degradation at Davis-Besse. In the absence of direct physical evidence, the basis for the staff's conclusion is experience with past boric acid corrosion events and the extension of that knowledge to the extreme Davis-Besse case. Uncertainties with regard to the technical details of the RPV head degradation (including the sequence, rate and nature of the mechanisms that resulted in the degradation) preclude a definitive conclusion to the technical Root Cause Analysis Report. However, the level of understanding of the root cause is sufficient for this licensee to proceed with use of the replacement head from the canceled Midland plant.

There are additional metallurgical generic lessons to be learned from the Davis-Besse event and to this end, further analysis of the event and the head itself will continue. The staff understands that FENOC intends to make a submittal providing the results from the metallurgical evaluation of the degraded area of the RPV head surrounding Nozzle 3 once those results have been evaluated. That portion of the reactor vessel head remains under quarantine until the metallurgical evaluation is complete.

Principal Contributor: A. Hiser

Date: March 31, 2003

KEY POINTS OF CONTACT

Licensee

A. Bless, Licensing
G. Dunn, Outage Manager
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LIST OF ITEMS OPENED CLOSED AND DISCUSSED

Opened

50-346/03-04-01	NCV	Failure to Implement Procedures Which Controlled the Fabrication and Installation of Temporary Modifications in Safety Related Systems.

Closed

50-346/03-04-01	NCV	Failure to Implement Procedures Which Controlled the Fabrication and Installation of Temporary Modifications in Safety Related Systems.
50-346/00-07-05	URI	Review of Licensee’s Documentation for Elimination of Fire Barrier Wrap in Component Cooling Water Pump Room.

LIST OF ACRONYMS USED

ADAMS	Agency-wide Document Access and Management System
CAC	Containment Air Cooler
CAQ	Condition Adverse to Quality
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CR	Condition Report
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
FENOC	FirstEnergy Nuclear Operating Company
IMC	Inspection Manual Chapter
IR	Inspection Report
LER	Licensee Event Report
NCV	Non-Cited Violation
NRC	United States Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PARS	Publicly Available Records
PVC	Poly-vinyl Chloride
SDP	Significance Determination Process
SCAQ	Significant Condition Adverse to Quality
SRB	Station Review Board
SSD	Safe Shutdown
TS	Technical Specifications
URI	Unresolved Item
USAR	Updated Safety Analysis Report
URI	Unresolved Item

LIST OF DOCUMENTS REVIEWED

1R04 Equipment Alignment

DB-OP-06262, Component Cooling Water System Operating Procedure, Rev. 3

1R05 Fire Protection

Fire Hazards Analysis Report

DB-FP-00007; Control of Transient Combustibles; Revision 01

1R12 Maintenance Effectiveness

Emergency Diesel Generator System Maintenance Rule (a)(1) Action Plan; November 20, 2001

Revised CTMT Hydrogen Analyzer System Maintenance Rule (a)(1) Action Plan; July 16, 2002

Medium Voltage AC System Maintenance Rule (a)(1) Action Plan

Revised Auxiliary Feedwater System Maintenance Rule (a)(1) Action Plan; January 9, 2002

Instrument Isolation Valves Maintenance Rule (a)(1) Action Plan; November 22, 2000

CR 01-01050; EDG 2 Fail to Start on DA31 Side

CR 01-01518; #1 EDG Inoperable Due to Ventilation Supply Fans Inlet Damper Failing

CR 01-01934; Inadequate Corrective Action for Stem Failure of Valve RC1BB

CR 02-03891; No Output Voltage Indicated With #1 EDG at 900 RPM

WO 02-3229-01; EWR 01-0413-00; Upgrade CTMT H2 Analyzer

1R13 Maintenance Risk and Emergent Work

NOP-OP-1005; Shutdown Safety; Rev. 1

NOP-OP-1005; Shutdown Safety; Rev. 2

Shutdown Status Worksheet; February 20, March 11, and March 12, 2003

13 RFO-19; Contingency Plan for Management Actions for Orange Risk Level During RCS Deep Drain (Less than 50 Inches)

1R14 Performance in Non-Routine Evolutions

DB-OP-6904; Shutdown Operations; Revision 04

1R15 Operability Evaluations

CR 03-00949; EDG 1-1 Performance Does Not Meet USAR Requirements

Operability Evaluation for CR 03-00949; February 8, 2003

CR 03-01301; EDG 2 Shutdown Due to the Air Intake Pressure Lo Alarm

CR 03-01341; EDG-2 Air Inlet Filter Condition

OE 2003-0004; Operability Evaluation for CR 03-01301 and CR 03-01341; February 19, 2003; Revision 0, Revision 01, and Revision 3

USAR 8.3.1.1.4, Diesel Generators

CR 03-01852; Emergency Diesel Generator Operability

CR 03-01803; NRC Resident Concerns Related to EDG 1 Performance and Operability Evaluation

CR 02-05922; LIR - EDG Voltage and Frequency During Loading Sequence Starting Discrepancy

CR 02-05925; LIR - EDG Transient Analysis During Loading Sequence Calculation

1R19 Post-Maintenance Testing

CR 03-01074; Relief Valve IST Program - Bellows Testing

CR 03-01108; Incomplete Post Maintenance Testing Specified for Decay Heat Pump #2 Maintenance

DB-PF-03237; Decay Heat Pump 2 Baseline Test; Revision 1

1R22 Surveillance Testing

DB-PF-03208; High Pressure Injection Pump Comprehensive and Check Valve Forward Flow Test for Train 2; Revision 2

DB-PF-03207; High Pressure Injection Pump Comprehensive and Check Valve Forward Flow Test for Train 1; Revision 3

DB-SC-03114; SFAS Integrated Time Response Test; Revision 3

DB-SC-04274; SBODG Dead Bus Load Test; Revision 1

DB-SC-03077; Emergency Diesel Generator 2 184 Day Test; Revision 3

DB-OP-06006; Makeup and Purification System; Revision 5

1R23 Temporary Plant Modifications

Temporary Modification 03-005; Intake Structure South Ventilation Penthouse; Installed March 1, 2003

4OA2 Problem Identification and Resolution

Memorandum "Davis-Besse Nuclear Power Station, Unit 1, Exemption From The Requirements of 10 CFR Part 50, Section III. G. of Appendix R (TAC No. MB1078); dated December 26, 2002.

4OA5 Other

CR 03-1494; Makeup Pump 2 Problems

DB-MM-09170; Makeup Pump Maintenance Procedure; Rev. 00

Mechanical Maintenance Problem Solving Plan for P37-2 (Makeup Pump 2); Dated February 24, 2003

CR 03-1519; Inadequate Work Practices on CAC 1 Service Water Trees

CR 03-1754; CAC 1 Bellows Assembly

CR 03-1674; CAC 1 Service Water Leaks

CR 03-1708; CAC 1 Service Water Header Weld Repair Purge Dam Removal

CR 03-1512; CAC 1 Lower West Cooling Coil Service Water Return Header Bellows Nicked

CR 03-1412; CAC Coils

CR 03-1777; CAC 2 and 3 Cooling Coils

DBE 03-00096; Containment Air Cooler 1 Installation of Temporary Bllind Flanges - At Risk Change 02-343AE; Dated March 4, 2003

Enercon Services Letter WES03-010; Assessment of the As-Installed Condition of the Containment Air Cooler Bellows to Support Availability; Dated March 5, 2003

Senior Flexonics Letter; Damaged Bellows Expansion Joint Capacities; Dated March 5, 2003

DBBP-VP-0002; Restart Readiness Review Extended Plant Outage; Revision 02

Problem Solving Plan for the CAC 2 PVC Jumper Catastrophic Failure; Dated March 3, 2003

CR 02-05024; Pressure Boundary Leakage Determination with Respect to RCS Thermowell Leakage

CR 02-05536; Crack Indication in J-Groove Weld of Old CRDM Nozzle 3

CR 02-05563; Nozzle Flexibility Assumed in Calculations 65A/B (Part II) is Non-Conservative

CR 02-06162; LIR-AFW-EQ-Qualification File DB1-034A

CR 02-07362; Management Did Not Address Identified Weaknesses in Design Basis Documentation

CR 02-08673; SHRR-Independent Review Requirements of Engineering Changes (NOP-CC-2003)

CR 02-08910; EQ Walkdowns; Additional EQ Equipment Needing Weepholes (Part 3)

CR 02-09770; SFP Negative Pressure Area Door Impaired, Potential Technical Specification 3.9.12 Violation

CR 03-00785; Missile Shield Lifting Rig

CR 03-00797; Non Quality Software Used to Track Receipt, Control, and Issue of Quality Parts