October 30, 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 05000346/2003018

Dear Mr. Myers:

On September 30, 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 October 7, 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, the report documents four inspector identified and two self revealing findings of very low safety significance (Green). These findings were determined to involve violations of NRC requirements. These findings did not present an immediate safety concern. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these four findings as Non-Cited Violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy.

If you contest any of the Non-Cited Violations in this report, 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 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.

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 05000346/2003018
w/Attachment: Supplemental Information

cc w/encl: The Honorable Dennis Kucinich
G. Leidich, President - FENOC
Plant Manager
Manager - Regulatory Affairs
M. O'Reilly, FirstEnergy
Ohio State Liaison Officer
R. Owen, Ohio Department of Health
Public Utilities Commission of Ohio
President, Board of County Commissioners
Of Lucas County
Steve Arndt, President, Ottawa County Board of Commissioners
D. Lochbaum, Union Of Concerned Scientists
J. Riccio, Green Peace
P. Gunter, NIRS

DOCUMENT NAME: C:\ORPCheckout\FileNET\ML033080433.wpd

**To receive a copy of this document, indicate in the box:"C**" = Copy without enclosure "**E**"= Copy with enclosure"**N**"= No copy

| | | | | | | |
|---|---|---|---|---|---|---|
| OFFICE | RIII | | RIII | | RIII | |
| NAME | Phillips/trn | | Lipa | | Grobe | |
| DATE | 10/23/03 | | 10/28/03 | | 10/30/03 | |

***OFFICIAL RECORD COPY***

<u>ADAMS Distribution</u>:
AJM
DFT
SPS1
RidsNrrDipmIipb
GEG
HBC
CST1
C. Ariano (hard copy)
DRPIII
DRSIII
PLB1
JRK1
DB0350

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

| | |
|---|---|
| Docket No: | 50-346 |
| License No: | NPF-3 |
| Report No: | 05000346/2003018 |
| Licensee: | FirstEnergy Nuclear Operating Company (FENOC) |
| Facility: | Davis-Besse Nuclear Power Station |
| Location: | 5501 North State Route 2<br>Oak Harbor, OH  43449-9760 |
| Dates: | August 21, 2003 through September 30, 2003 |
| Inspectors: | S. Thomas, Senior Resident Inspector<br>J. Rutkowski, Resident Inspector<br>M. Salter-Williams, Resident Inspector<br>K. Walton, Senior Licensing Inspector |
| Approved by: | Christine A. Lipa, Chief<br>Branch 4<br>Division of Reactor Projects |

Enclosure

# TABLE OF CONTENTS

## SUMMARY OF FINDINGS

IR 05000346/2003018; 8/21/2003 - 9/30/2003; Davis-Besse Nuclear Power Station; Refueling and Outage, Surveillance Testing, Event Followup, and Other Activities.

This report covers a 6 week period of resident inspection. The inspection was conducted by resident and region based inspectors. Six Green findings associated with six Non-Cited Violations were identified. 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.

### A. <u>Inspector-Identified and Self-Revealing Findings</u>

**Cornerstone: Mitigating Systems**

- Green. An NRC identified finding of very low safety significance was identified when the inspectors discovered a significant amount of loose material in the containment building, subsequent to a final closeout inspection performed by senior licensee management.

  The inspectors determined that this finding was of more than minor safety significance because if left uncorrected, it would have become a more significant safety concern. The finding was of very low safety significance because the licensee corrected the identified deficiencies prior to transitioning to an operational mode that required the containment emergency sumps to be operable. This issue was a Non-Cited Violation of Technical Specification 3.5.2, which required the removal of loose materials that could challenge the containment emergency sump prior to establishing containment integrity. (Section 1R20.1)

- Green. A self-revealing finding of very low safety significance was identified when it was determined that the procedure for testing the response time of the auxiliary feedwater pump 1 turbine did not adequately describe the acceptance criteria for successful completion of the test.

  The inspectors determined that this finding was of more than minor safety significance because if it was left uncorrected, it would become a more significant safety concern. The finding was of very low safety significance because, even though the procedure inadequacy led the operators to incorrectly classify the auxiliary feedwater pump 1 as inoperable, the licensee promptly implemented the appropriate acceptance criteria and properly reclassified the pump's operability status. This was a Non-Cited Violation of a procedure required by Technical Specification 6.8.1.a. (Section 1R22.2)

- Green. A self-revealing finding of very low safety significance was identified when control room staff did not adequately monitor and control reactor coolant system pressure during reactor coolant system heatup which resulted in valve CF1B from the core flood tank emergency system opening unexpectedly.

The inspectors determined that this finding was of more than minor safety significance because it: (1) involved the configuration control attribute of the Mitigating Systems Cornerstone; and (2) affected the cornerstone objective to ensure the availability, reliability, and capability of the systems that respond to initiating events to prevent undesirable consequences. This finding was of very low safety significance because the operators terminated the event in a timely manner and the resulting pressure transient did not significantly challenge plant equipment. This was a Non-Cited Violation of a procedure required by Technical Specification 6.8.1.a. (Section 4OA3.1)

- Green. An NRC identified finding of very low safety significance was identified for the failure of the licensee to address all significant causal factors related to the configuration control aspects associated with the installation of unqualified relays in the SFAS system.

  The inspectors determined that this finding was of more than minor safety significance because it: (1) involved the configuration control attribute of the Mitigating Systems Cornerstone; and (2) affected the cornerstone objective to ensure the availability, reliability, and capability of the systems that respond to initiating events to prevent undesirable consequences. This finding was of very low safety significance because none of the five relays were installed in redundant channels; therefore, the redundant SFAS actuated component remained capable of performing its designated safety function. This was a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI. (Section 4OA3.3)

- Green. An NRC identified finding of very low safety significance was identified when the inspectors discovered that procedural guidance which governed the performance of the Immediate Action Maintenance (IAM) process did not exist.

  The inspectors determined that this finding was of more than minor safety significance because if left uncorrected the finding would become a more significant safety concern. This finding was of very low safety significance because, even in the absence of procedural guidance on how to implement the IAM process, the correct technical procedures were utilized to adjust the 1 turbine driven feedwater pump governor and the appropriate retests were performed to evaluate the adequacy of the maintenance. This was a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V. (Section 4OA5.1)

- Green. An NRC identified finding of very low safety significance was identified when the inspectors discovered that Operations management inappropriately authorized the performance of the IAM process to perform adjustments on 1 turbine driven auxiliary feedwater pump governor.

  The inspectors determined that this finding was of more than minor safety significance because if left uncorrected the finding would become a more significant safety concern. As stated in a number of the licensee’s procedures, the IAM process should only be implemented to affect maintenance required to mitigate failures that potentially threaten public or personnel health or reactor safety. The expedited nature of the IAM process was derived from the performance of the normal work reviews and documentation after the maintenance was performed. As a result, the potential for errors, associated with the work performed under the IAM process and the adequacy of the retest to validate the effectiveness of the maintenance, was increased. This finding was of very low safety significance because the actual impact of the inappropriate implementation of the IAM did not adversely impact the adjustment of the 1 turbine driven feedwater pump governor and an adequate retest was performed to evaluate the adequacy of the maintenance. This was a Non-Cited Violation of Technical Specification 6.8.1.a. (Section 4OA5.2)

## B. Licensee Identified Findings

No findings of significance were identified.

# 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." Significant dates for this extended outage were as follows:

- fuel was removed from the reactor on June 26, 2002;
- entered operational Mode 6 on February 19, 2003;
- fuel reload was completed on February 26, 2003;
- entered operational Mode 5 on March 12, 2003;
- entered operational Mode 4 on September 13, 2003;
- entered operational Mode 3 on September 14, 2003;
- completed the normal operating pressure test for the reactor coolant system and started cooldown to Mode 5 on September 30, 2003;

Just prior to the conclusion of the inspection period, the licensee experienced a reactor trip. As a result of the trip, the licensee suspended cooldown to evaluate the trip and the reasons for the trip. The trip and the followup actions will be discussed in the next resident inspection report.

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 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, Barrier Integrity, and Emergency Preparedness**

1R04 Equipment Alignment (71111.04Q)

a. Inspection Scope

The inspectors verified equipment alignment and identified any discrepancies that impacted the function of system components and the associated increase in 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 the 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 verifying that:

- 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 evaluated the material condition of the equipment to verify that there were no significant conditions not already in the licensee's corrective action system. The following two samples were inspected:

- high pressure injection train 1; and
- high pressure injection train 2.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

.1 Area Inspections

a. Inspection Scope

The inspectors conducted fire protection inspections, which were focused on the availability, accessibility, and condition of fire fighting equipment, the control of transient combustibles, and 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 three areas were inspected:

- emergency core coolant system pump room 1;
- emergency core coolant system pump room 2; and
- Service Water Screen Wash Pump Room.

b. Findings

No findings of significance were identified.

.2 Fire Brigade Drill

a. Inspection Scope

The inspectors observed a fire brigade drill in the auxiliary boiler room to evaluate the readiness of the licensee's personnel to prevent and fight fires. The inspectors verified that protective clothing/turnout gear was properly donned; that the fire area was entered in a controlled manner; that the fire hose lines were capable of reaching the fire hazard locations and the lines were laid out without flow constrictions; that sufficient fire fighting equipment was brought to the scene by the fire brigade to properly perform their firefighting duties; and that the fire brigade leader's fire fighting directions were thorough, clear and effective.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

The inspectors observed two separate training activities conducted in the simulator for the operating crews.

On September 12, 2003, the inspectors observed an operating crew practice taking the reactor coolant system from operational Mode 5 to Mode 3 on the simulator. This heatup evolution training was necessary to ensure that the crew could successfully demonstrate proficiency in operating the plant during plant mode changes. The inspectors observed the crews performance with respect to component operation, procedure adherence and communications.

On September 16, 2003, the inspectors observed an operating crew during "just in time" training to review operator actions during an event where the core flood tank outlet valve opened unexpectedly and pressurized piping within the decay heat system and the core spray system (Section 4OA3). The training provided an overview of the event and crew discussion of what actions the crew should have taken and would take in future similar circumstances. The inspectors noted management involvement in the brief and verified that relevant events were discussed including management and crew expectations for future actions.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope

During this inspection period the licensee reviewed various events associated with the service water system and the licensee identified two (2) functional failures as defined in the licensee's implementation of the maintenance rule:

- setpoint drift of pressure switch 1377A (CR 03-05147)
- failure of pressure switch 1376A (CR 03-06317)

The service water system has a maintenance rule performance criteria of no more than one (1) functional failure per cycle. Additionally, during the report period the service water system had other condition reports that documented questions and issues with the system and system components including questions on flow balancing of the system.

The inspectors reviewed whether the licensee properly implemented the Maintenance Rule, 10 CFR 50.65, for the service water system. Specifically, the inspectors reviewed the performance problems that were classified as maintenance rule functional failures, the standard for trending equipment availability, the present maintenance rule classification of the system, and the requirements for exceeding the functional failure performance criteria. The inspectors additionally reviewed other condition reports that addressed service water issues and reviewed with the licensee their basis for system operability based on results from flow balancing testing. The inspectors also performed partial walkdowns of the service water system as part of this inspection.

b. Findings

No findings of significance were identified.

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

.1 Routine Risk Significant Activities

a. Inspection Scope

The inspectors reviewed the licensee's response to risk significant activities. These activities were chosen based on their potential impact on increasing overall plant risk. The inspection was conducted to verify the planning, control, and performance of the work were done in a manner to reduce overall plant 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 four risk significant issues were evaluated by the inspectors:

- During the last week of August 2003, the licensee drained decay heat train 1 for scheduled maintenance and modification work associated with this train. While this work was ongoing, contingency plan 13RFO-33, Revision 1, "Work with Decay Heat Pump #2 Running with Work on HPI Pump 2 Minimum Recirculation Modification in ECCS Room #2," was implemented. The inspectors reviewed the contingency plan and verified that all compensatory measures outlined in the contingency plan were being implemented.

- On September 17, 2003, containment spray pump 1 failed to start when required by a surveillance test. The licensee determined that the containment spray pump supply breaker had tripped immediately upon a start signal. Because of previous issues associated with the breaker tripping for both containment spray pumps, the licensee formed a problem solving team and eventually determined that a ground fault sensing circuit was responsible for the trip. After determining that the ground fault trip was not required, the licensee processed a design change and removed the fault sensing circuit from containment spray pump 1. The inspectors attended several meetings of the problem solving team, reviewed the rationale for the design change, and observed post design change testing of containment spray pump 1. The inspectors also reviewed the licensee's evaluation that determined that additional testing of containment spray pump 2 was required to verify that containment spray pump 2 was not experiencing the same failure as seen on containment spray pump 1.

- On September 20, 2003, with the reactor coolant system pressure approximately 1525 psig, the Control Room received an annunciator for Safety Feature Actuation System (SFAS) reactor coolant system pressure less than 450 psig. The alarm was initiated by SFAS channel 3. The licensee placed the channel in trip and initiated actions to identify the cause. A connector problem was identified and corrected. The inspectors observed the licensee's response to the issue and reviewed their corrective action.

- On September 20, 2003, the licensee, during a regular plant tour route, found the service water pump 2 strainer running with the blowdown valve closed. Further investigation revealed that the breaker thermal overloads for the strainer motor controller had tripped and could not be reset. This condition prevented the strainer blowdown valve from opening on high stainer differential pressure or when the strainer was running. Such a condition would prevent the strainer from cleaning itself. As an interim compensatory measure, the licensee provided guidance to operators on how to manually blowdown/clean the strainer and directed that the strainer status be verified at approximately 2 hour intervals. Subsequently, the licensee took action to correct the situation. The inspectors reviewed the licensee's response to the issue including the licensee's determination of extent of condition.

b. Findings

No findings of significance were identified.

.2 Auxiliary Feedwater Pump 1 Response Time Testing

a. Inspection Scope

On September 25, 2003, the licensee was conducting response time testing of its steam driven auxiliary feedwater pumps. In response to a second response time failure of the Auxiliary Feedwater Pump 1 (Section 1R22), the licensee chartered a problem solving team which developed a problem solving plan. The inspectors periodically observed meetings of the team and reviewed plans, work orders, and procedures that were identified during the problem solving. The inspectors also reviewed the initial post maintenance test and additional and follow up test results.

The Auxiliary Feedwater Pump 1 governor/governor valve linkage had been disassembled and reassembled as part of scheduled maintenance early in the current outage. The initial time response testing was the first time normal steam pressure was available for the response time testing since that maintenance. The licensee's developed Problem Solving Plan process identified that it would be prudent to reestablish linkage alignment by removing the linkage and realigning it using an existing approved procedure. Subsequent to that reassembly, auxiliary feedwater pump 1 response time testing was satisfactorily performed. The licensee also decided to rerun the test several times at periods of 12 to 24 hours to verify corrective action and to minimize any preconditioning effects on test results.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14)

.1 Reactor Coolant System Heatup

a. Inspection Scope

The inspectors monitored the licensee's reactor coolant heatup from Mode 5 (< 200 °F) to normal no-load reactor coolant temperature (approximately 532 °F). The scope of this inspection included pre-evolution briefs, operator performance, risk assessment, and staff responses to unexpected plant challenges. These challenges included:

- containment personnel airlock door malfunction;
- excessive leakage by valve SP7B (steam generator 1 startup feedwater control valve);
- elevated reactor coolant 2-2 seal return temperature;
- main steam piping water hammers during initial entry into Mode 4;
- unexpected opening of CF1B (core flood tank 1 isolation valve) ;
- SFAS channel 3 pressure low trip due to faulty transmitter connection;
- blown fuses during AFW pump interlock testing;
- service water strainer 2 thermal overload trip; and
- containment spray pump 1 breaker trip during starting.

On September 22, 2003, the reactor coolant system reached normal operating pressure (2155 psig) and no-load temperature (approximately 532 °F). The inspectors sampled the following issues associated with the heatup for further inspection. Specific issues further evaluated in this report by the inspectors were as follows:

- unexpected opening of CF1B (Section 4OA3);
- SFAS channel 3 pressure low trip due to faulty transmitter connection (Section 1R13);
- blown fuses during AFW pump interlock testing (Section 1R22);
- service water strainer 2 thermal overload trip (Section 1R13); and
- containment spray pump 1 breaker trip during starting (1R13).

b. Findings

No findings of significance were identified.

.2 Reactor Coolant Pump (RCP) Bumps

a. Inspection Scope

The inspectors reviewed operations personnel conduct during bumping of reactor coolant pumps to determine if the evolution was conducted in a safe and conservative manner. The inspectors reviewed operations procedures, and facility administrative procedures to determine the acceptance criteria for the inspection.

b. Findings

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 and applicable licensee operability evaluations were reviewed 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 eight issues evaluated were:

- evaluation of 3/8" x 2.5" stem-to-disc pins and disc seat fragments from DH14B (Decay Heat Cooler 1 Outlet Flow Control Valve) potentially in the reactor coolant system;

- operability evaluation 2003-027 (Service Water Train 2 Flow Less Than Flow Balance Acceptance Criteria);
- operability evaluation 2003-024 (Containment Air Cooler 2 and 3);
- operability evaluation 2003-016 (2P/2N Battery Plate Support Rods);
- operability evaluation 2003-013 (Preliminary Davis-Besse AC System Analysis Results);
- operability evaluation 2003-022 (Replace SW/CCW Time Delay Relays in AC101 and AD101);
- operability evaluation 2003-029 (Core Flood Tank Pressurization of Train 1 Decay Heat Piping and Containment Spray Piping); and
- CR 03-06253 (Update Sump Strainer Calculations for Adjusted Debris Loading)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage (71111.20)

.1 Containment Closeout

a. Inspection Scope

The inspectors evaluated the licensee's efforts to remove loose debris from containment as required by Plant Procedure DB-OP-06900, Attachment 11, Revision 15, and Technical Specification 4.5.2.c. The inspectors evaluated each area of containment subsequent to final closeout inspections performed by senior operations management personnel.

b. Findings

Introduction. The inspectors identified a Non-Cited Violation of Technical Specification 3.5.2 having very low safety significance when a significant amount of debris was found in several areas of the containment building subsequent to final inspections by senior licensee operations staff.

Description. On September 10, 2003, operations senior management personnel conducted the final containment closeout inspection of the containment building to satisfy the Technical Specification surveillance requirements that required, in part, that no loose debris (rags, trash, clothing, etc.) was present that could be transported to the containment emergency sump and cause restriction of the pump suction during loss of coolant accident conditions. Additional licensee guidance on what actions satisfied the Technical Specification surveillance requirement was contained in Attachment 11 of procedure DB-OP-06900, "Plant Heatup," Revision 15. Step 2.0 of this Attachment further clarified "loose debris" as:

- rags, trash, sources of fibrous material, or clothing which could be transported to the containment emergency sump;
- unqualified equipment tags or other tags (clearance tags, maintenance tags, out of service tags, or other information tags); and
- exposed tape or labels that are not qualified.

The inspectors accompanied a licensee senior manager during the final containment closeout inspection. After the senior manager informed the inspectors that he had completed his final inspection in a given area and was satisfied with the cleanliness of that area, the inspectors performed an independent inspection of each area's cleanliness. The inspector identified the following material in these areas:

- one medium size and several small plastic bags;
- several small plastic FME covers;
- a 6 foot portable metal ladder;
- pieces of masking tape, duct tape, and electrical tape in several locations;
- a posted maintenance work tag,
- several unqualified black plastic tie straps,
- areas that contained fine loose debris or paint chips;
- unattached metal identification tags;
- unattached metal fasteners (nuts, bolts, nails, wire) in several locations;
- several 8 x 11 inch paper pages; and
- a small primary system valve with active packing leakage.

The inspectors debriefed their findings with the licensee. The licensee documented this issue in their corrective action program and corrected the deficiencies prior to final containment building closeout.

<u>Analysis</u>. The inspectors determined that this finding was of more than minor safety significance because if it was left uncorrected, it would become a more significant safety concern. The finding is of very low safety significance because the licensee corrected the identified deficiencies prior to transitioning to an operational mode that required the containment emergency sumps to be operable.

<u>Enforcement</u>. The performance deficiency associated with this issue is the failure to adequately identify and remove loose debris from the containment building prior to determining that containment was ready to support plant operation in Mode 3. Technical Specification 3.5.2 requires, in part, that two independent ECCS (emergency core cooling systems) be operable in operational Modes 1, 2, and 3. As part of the requirements to demonstrate operability of each ECCS subsystem, Surveillance Requirement 4.5.2 requires that an inspection be performed to verify that no loose debris is present in containment which could be transported to the containment emergency sump and cause restriction of the pump suction, prior to establishing containment integrity. Contrary to the requirements of Technical Specification 3.5.2, an adequate final visual inspection was not performed to satisfy the requirements of this Surveillance Requirement. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 03-07628), it is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000346/2003018-01).

1R22 Surveillance Testing (71111.22)

.1 Routine Surveillance Observations

a. Inspection Scope

The inspectors observed the surveillance test and/or 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 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 eight activities were evaluated:

- DB-SP-03218 (HPI Train 1 Pump and Valve Test);
- DB-SP-03155 (AFW Train 1 Flow Path to SG Verification);
- DB-SC-03114 (SFAS Integrated Time Response Test (Actuation Channel 1));
- DB-SC-03114 (SFAS Integrated Time Response Test (Actuation Channel 2));
- DB-SP-03166 (AFP 2 Response Time Testing);
- DB-SP-03001 (Service Water Loop 2 Integrated Flow Balance Procedure);
- DB-SC-03271 (Control Rod Drive Program Verification); and
- DB-PF-03080 (AFW Check Valves AF1, AF2, AF15, and AF16 Reverse Flow Checks).

b. Findings

No findings of significance were identified. DB-PF-03080 (AFW Check Valves AF1, AF2, AF15, and AF16 Reverse Flow Checks) is further discussed in Section 4OA5.

.2 Auxiliary Feedwater Pump 1 Response Time Testing

a. Inspection Scope

The inspectors reviewed the performance data gathered from the initial performance of surveillance test DB-SP-3157, “Auxiliary Feedwater Pump 1 Response Time Test.” Additionally, the inspectors evaluated the several retests performed by the licensee to identify and correct an equipment performance issue identified during the course of testing.

b. Findings

Introduction. A self-revealing Non-Cited Violation of Technical Specification 6.8.1.a having very low safety significance was identified subsequent to the performance of DB-SP-3157, “AFP 1 Response Time Test,” when it was determined that the procedure did not adequately describe the acceptance criteria for successful completion of the test.

Description. Davis-Besse Technical Requirements Manual Section 3/4.3.3.2, Steam and Feedwater Rupture Control System Instrumentation(SFRCS), documented that the Auxiliary Feed Pump(s) will have a response time of less than or equal to 40 seconds (from signal initiation to full speed). Technical Specification 3.7.1.2 specifies that the auxiliary feedwater system shall be operable in Modes 1, 2, and 3 and, if a train was inoperable, it must be restored to operable status within 72 hours or the plant needs to be in hot shutdown within the next 12 hours.

The response time, which was measured using stop watches, started when a SFRCS signal was introduced using a pushbutton in the Control Room, and stopped when the pump was at full operating speed. To this measured time, 1.9 seconds was added for instrument inaccuracy and this time was compared to the acceptance time of 40 seconds. On September 23, 2003, Auxiliary Feedwater Pump 1 failed to reach specified full speed in less than or equal to 40 seconds. Actual times were in the range of 40.1 to 42 seconds.

Initial Test (September 23, 2003)
An approximate sequence of the testing was as follows:

- Upon actuation from SFRCS , the AFP 1 did not reach rated speed within the 40 second time requirement. The actual time was 40.16 seconds.
- At 0011 (September 23, 2003), AFW train 1 was declared inoperable and the action statement (required by LAR 03-0008) that required cooldown within 2 hours was entered.
- At 0143, a second test was run and a time of 38.2 seconds was obtained. The licensee exited the 2 hour cooldown action statement.
- At 0150, AFW train 1 was declared operable.
- At 0325, operations received engineering input that overall response time requires the addition of 1.9 seconds to the actual observed time to account for instrument inaccuracies. Based on this information, the response time exceeded the 40 second limit. Train 1 was declared inoperable and the action statement (required by LAR 03-0008) that required cooldown within 2 hours was entered.
- At 0429, repeated the response time testing. Result was 37.48 seconds.
- At 0511, system engineer determined that the AFP turbine governor required adjustment.
- At 0520, commenced reactor coolant system cooldown.
- At 0522, AFP turbine governor compensating needle valve was opened ½ turn.
- At 0535, repeated the response time testing. Result was 34.94 seconds.
- At 0547, repeated the response time testing. Result was 34.20 seconds.
- At 0611, AFW train 1 was declared available.
- At 0617, exited LAR cooldown action statement and secured reactor system cooldown. Actual primary system cooldown was approximately 3°F.

After a series of runs and adjustments to the auxiliary feedwater pump governor, the licensee declared the pump operable. To address potential pre-conditioning concerns with the final operability runs, the licensee performed the final response time test after an elapsed time of approximately 24 hours from the last test.

Reverification Test (September 24-25, 2003)
Late on September 24, 2003, the licensee repeated the response time testing with an approximate sequence as follows:

- At 2213 on September 24, 2003, upon manual actuation from SFRCS, AFP 1 did not reach rated speed within the 40 second time requirement. The actual time was 38.4 and 38.7 seconds (2 stopwatches) and with the application of the 1.9 second instrument accuracy penalty, exceeded the acceptance criteria.
- At 0007, on September 25, the licensee commenced a cooldown of the reactor coolant system.
- Two additional response time tests were conducted and completed at about 0440. Response times, without the instrument penalty time, were 34.77 and 33.99 seconds. This was a pattern similar to the pattern observed during earlier testing.
- Licensee identified slow opening of the steam admission valve (MS5889A) as potential cause of the slow response time and issued a work order to adjust the opening time.
- On the morning of September 25, the licensee chartered a problem solving team to research the cause and implement appropriate corrective actions.

The licensee's problem solving team reviewed various aspects of the problem and developed an approach that included completely removing the governor/governor valve mechanical linkage and reassembling it according to an existing maintenance procedure (Section 1R13). Subsequent to this activity the pump response time surveillance was successfully completed.

Analysis. The inspectors determined that this finding was of more than minor safety significance because if it was left uncorrected, it would become a more significant safety concern. The finding is of very low safety significance because, even though the procedure inadequacy led the operators to incorrectly classify the auxiliary feedwater pump 1 as operable, the licensee promptly implemented the appropriate acceptance criteria and properly reclassified the pump's operability status.

Enforcement. The performance deficiency associated with this issue is the failure to incorporate the proper acceptance criteria into a procedure that is used to determine the operability of a safety related component. Technical Specification 6.8.1.a requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33 requires specific procedures for surveillance tests, inspections, and calibrations for systems, including auxiliary feedwater system. The licensee developed DB-SP-03157, "AFP 1 Response Time Test," Revision 05, a safety related procedure, in part, to check that the auxiliary feed pump turbine 1 develops greater than or equal to 3666 revolutions per minute in less than or equal to 40 seconds (the time specified in Technical Requirements Manual LCO 3.3.2.2, Steam and Feedwater Rupture Control System Instrumentation, Surveillance Requirement 4.3.2.2). Contrary to this requirement, the procedure, if performed as written, is inadequate because the procedure does not state that instrument response time inaccuracies must be added to the observed turbine response times and that combined time is required to be less than or equal to 40 seconds. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 03-08067) it is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000346/2003018-02).

.3 Auxiliary Feedwater System Low Pressure Interlock Test Failure

a. Inspection Scope

The inspectors observed the briefing and initiation of functional test of the auxiliary feedwater pump 1 test of the inlet isolation on low steam line pressure per section 4.6 of DB-SP-03152, AFW Train 1 Level Control, Interlock and Flow Transmitter Test. The test failed and subsequently a blown fuse was found in the control circuit of MS 106, main steam line 1 to auxiliary feedwater pump 1 isolation. After identifying that the fuse had blown previously, the licensee formed a problem solving team to investigate and correct the cause of the failure. The inspectors observed various segments of the problem solving team’s activities and reviewed their conclusions.

b. Findings

No findings of significance were identified.

## 4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

.1 Resolution of Mode 4 Restraints

a. Inspection Scope

The inspectors reviewed Mode 4 restraint condition reports and corrective actions taken by the licensee to address deficient conditions. The inspectors evaluated the condition reports for appropriate inclusion into the Mode 4 Restraint Checklist. The inspectors reviewed the licensee’s corrective actions and spoke to licensee personnel about identified problems and corrective actions.

b. Findings

No findings of significance were identified.

.2 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee’s corrective action system at the appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Minor issues entered into the licensee’s corrective action system as a result of inspectors observations are included in the list of documents reviewed which are attached to this report.

b. Findings

Licensee failed to address all significant causal factors related to the configuration control aspects associated with the installation of unqualified relays in the SFAS system. (Section 4OA3.3)

4OA3 Event Followup (71153)

.1 Unexpected Opening of CF1B (core flood tank 1 isolation valve)

a. Inspection Scope

The inspectors reviewed the performance of the control room operators prior to the unexpected opening of CF1B and the performance of the station staff in evaluating the impact of the valve's opening on adjacent plant systems.

b. Findings

Introduction. An inspector identified Non-Cited Violation of Technical Specification 6.8.1.a having very low safety significance was identified when control room staff did not adequately monitor and control reactor coolant system pressure which resulted in CF1B opening unexpectedly. Procedure DB-OP-0000, "Conduct of Operations," Revision 06, required, in part, that Operations personnel "shall be responsible for monitoring the equipment, instrumentation and controls within their area and taking timely and proper actions to ensure safe, conservative operation of the unit." Even though the licensee had an individual whose main duty was to monitor the reactor coolant system pressure, no action was taken to prevent reactor coolant pressure from increasing to the point where CF1B automatically actuated.

Description. During the performance of the reactor coolant system (RCS) heatup, in preparation for the normal operating pressure test, CF1B opened. The normal sequence for this portion of the plant heatup procedure was as follows:

- At approximately 600 psig in the RCS, close the breakers which power the CF1A and CF1B valves (core flood tank outlet isolation valves).
- At approximately 675 to 700 psig in the RCS, perform Pressure Operated Relief Valve (PORV) testing and leak check testing of DH76 and DH77 (check valves which isolate decay heat trains 1 and 2 from the ECCS header).
- Perform core flood tank isolation valve interlock test. (This tests the actuation relay by gradually raising RCS pressure and verifying that an open signal for CF1A and CF1B is generated and that the valves stroke open when RCS pressure is approximately 770 psig.)

The applicable plant conditions that existed just prior to the event were:

- 2-1 and 2-2 reactor coolant pumps were operating; no reactor coolant pumps operating in loop 1;
- loop 2 reactor coolant pressure was approximately 650 psig; loop 1 reactor coolant pressure was approximately 700 psig;

- core flood tank 1 pressure was approximately 575 to 600 psig;
- reactor coolant system pressure was being monitored, as required by procedure, from each loop; and
- the reactor operator was maintaining the required pressure band by monitoring loop 2 pressure indication.

At approximately noon on September 15, 2003, as the reactor operator continued to increase RCS pressure to establish the plant conditions for the required plant testing (675 to 700 psig), he received indication that CF1B opened, core flood tank 1 level was decreasing, and that reactor coolant drain tank level increased and subsequently pumped down automatically. The control room staff took immediate emergency action to go to “pressure test” on SFAS channel 3, which facilitated the shutting of CF1B from the control room. These actions were taken by the control room staff by implementing the appropriate procedure. Once the valve was shut and its associated breaker was opened, SFAS channel 3 was restored to normal. The final core flood tank 1 level indicated a decrease of approximately 2 feet (1000 gallons). The control room staff further reduced RCS pressure to approximately 620 psig and ceased further RCS heat-up activities pending further evaluation of the event.

Evaluation of this event revealed the following:

- A larger than normal pressure difference existed between RCS loop 1 and RCS loop 2 (approximately 50 psig) due to no reactor coolant pumps operating in RCS loop 1.
- The reactor operator was using the loop 2 pressure indication (the lower pressure) to control his RCS pressure band.
- The control room watchstander assigned to track the pressure trends in both loops did not identify the potential impact of the higher loop 2 pressure on the actuation setpoint of the relay that automatically opens CF1B.
- The pressure in loop 1 was allowed to reach the actuation setpoint of the relay which sends an open signal to CF1B. SFAS channel 3 normally senses RCS loop 1 pressure as its input. (CF1A did not open because it received its actuation signal from SFAS channel 2, which sensed RCS loop 2 pressure.)
- Subsequent testing of the actuation relay verified that its setpoint was within allowable tolerances.
- Since the testing of DH76 and DH77 had not been performed, the requisite seating of these valves had not been accomplished. This allowed the water discharged from the core flood tanks to enter Decay Heat train 1 piping and subsequently cause the suction and/or discharge relief valves to relieve pressure to the reactor coolant drain tank.
- Procedure DB-OP-06900, “Plant Heatup,” Revision 15, was deficient because, due to the differences in tolerances between the pressure instruments that monitor loop 1 RCS pressure, loop 2 RCS pressure, and SFAS channel 3 RCS pressure, it was unlikely that the reactor operator could establish the prescribed pressure band for the testing sequence (675 to 700 psig) without also reaching the actuation setpoint for CF1B.

The licensee implemented several actions to address the deficiencies associated with this issue. These actions included the following:

- implemented their problem solving and decision process;
- performed a system walkdown of the decay heat system train 1 and associated piping;
- performed an engineering evaluation of the impact of the pressure transient on the decay heat system train 1 and associated piping;
- removed the licensed operators that performed the evolution from the shift and subjected them to an extensive remediation program prior to allowing them to assume the watch again; and
- revised procedure DB-OP-06900, “Plant Heatup,” by adjusting the sequence of key testing activities and the plant conditions required to support those activities to reduce the opportunities for errors.

<u>Analysis</u>. In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP Phase 1 screening and determined that the issue affected the Reactor Safety Strategic Performance Area. The finding was more than minor because it: (1) involved the configuration control attribute of the Mitigating Systems Cornerstone; and (2) affected the cornerstone objective to ensure the availability, reliability, and capability of the systems that respond to initiating events to prevent undesirable consequences. This finding was of very low safety significance because the operators terminated the event in a timely manner and the resulting pressure transient did not significantly challenge plant equipment.

<u>Enforcement</u>. This is a performance issue because preventing the automatic actuation of CF1B was reasonably within the licensee’s ability to control and actuation could have been prevented. The performance deficiency associated with this event is the control room staff did not adequately monitor and control reactor coolant system pressure which resulted in CF1B opening unexpectedly. Technical Specification 6.8.1.a requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33 requires Administrative Procedures which address authorities and responsibilities for safe operation and shutdown. The licensee developed DB-OP-0000, “Conduct of Operations,” Revision 06, a safety related procedure, to, in part, provide guidance on how Operations personnel carry out their duties and responsibilities as delineated in Station Procedures, Policies, Directives, and Manuals. Step 6.2.1.c of DB-OP-0000 states “Operations personnel shall be responsible for monitoring the equipment, instrumentation and controls within their area and taking timely and proper actions to ensure safe, conservative operation of the unit.” Contrary to this requirement, even though the licensee had an individual whose main duty was to monitor the reactor coolant system pressure, no action was taken to prevent reactor coolant pressure from increasing to the point where CF1B automatically actuated. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program (CR 03-07746) it is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000346/2003018-03).

.2 (Closed) Licensee Event Report (LER) 50-346/02-002-00: Reactor Coolant System Pressure Boundary Leakage Due to Primary Water Stress Corrosion Cracking of Control Rod Drive Mechanism Nozzles and Reactor Pressure Vessel Head Degradation

a. Inspection Scope

The inspectors reviewed LER 2002-002, which documented through-wall cracking in three control rod drive mechanism (CRDM) nozzles with pressure boundary leakage from Nozzle 3 and degradation of the vessel head.

b. Findings

Red. Ten apparent violations of NRC requirements were previously identified, for licensee performance deficiencies related to the CRDM nozzle cracking and pressure boundary leakage (See NRC Inspection Reports 50-346/02-008 and 50-346/03-016).

Description: On February 16, 2002, the Davis-Besse facility began its 13th refueling outage, which included inspections of the CRDM nozzles in accordance with NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles." On February 27, 2002, the licensee notified the NRC that CRDM Nozzles 1, 2 and 3 exhibited axial through-wall indications. The licensee initially decided to repair these three nozzles plus two other nozzles which had crack indications that did not appear to be through-wall. During subsequent CRDM nozzle repair activities, the licensee identified substantial degradation of the vessel head. Corrosion, caused by the boric acid leakage through the cracks in Nozzle 3, damaged the vessel head next to this nozzle, creating an irregular cavity about 4 inches by 5 inches and approximately 6 inches deep. The cavity penetrated the carbon steel portion of the vessel head, leaving only the stainless steel lining. In addition, during this same time period, the licensee identified a much smaller cavity in the reactor vessel head after machining away the lower portion of Nozzle 2 during repair activities. The licensee subsequently replaced the reactor vessel head as a corrective measure for these conditions.

On March 13, 2002, the NRC issued Confirmatory Action Letter No. 3-02-001 regarding the reactor pressure vessel head degradation at the Davis-Besse Nuclear Power Station and initiated an Augmented Inspection Team (AIT). The AIT developed a sequence of events, interviewed plant personnel, collected and analyzed factual information and evidence relevant to the reactor vessel head material loss, and conducted visual inspections of the reactor vessel head. The AIT concluded its inspection on April 5, 2002, and issued NRC Inspection Report 50-346/02-03 on May 3, 2002.

On August 9, 2002, the NRC completed a special inspection focused on compliance with NRC rules and regulations as they relate to the facts and circumstances associated with the degradation of the reactor pressure vessel head documented in the AIT report. The results and conclusions of this special inspection were documented in NRC Inspection Report 50-346/02-08 issued on October 2, 2002.

The licensee conducted a root cause determination and concluded that the probable cause of the axial through wall flaws was primary water stress corrosion cracking and that the degradation of the vessel head was caused by boric acid corrosion. On

April 18, 2002, and September 23, 2002, the licensee submitted Revision 0 and Revision 1, respectively, of the Technical Root Cause Analysis Report to the NRC for review. On August 21, 2002, the licensee submitted the Management and Human Performance Root Cause Analysis Report to the NRC. By letter dated January 9, 2003, the licensee documented the results of additional evaluations which included reviews of the Quality Assurance Oversight, Operations, and Engineering areas. These root cause reports and reviews were submitted to the NRC pursuant to the requirements of the NRC Confirmatory Action Letter dated March 13, 2002.

An NRC Davis-Besse Oversight Panel was created in April 2002 to make sure that all corrective actions, required to ensure that Davis-Besse can operate safely, are taken before the plant is permitted to restart. The Panel was established under the Agency's Manual Chapter 0350 and created a "restart checklist" categorizing 31 actions in seven major areas that must be completed before the NRC can make a restart decision. As of September 2003, the Oversight Panel determined that the licensee had adequately completed 18 of those actions. The completed checklist items included Items Nos. 1.a and 1.b, associated with NRC review of the licensee root cause determinations as documented in NRC inspection reports No. 50-346/03-04 and 50-346/02-18. The NRC also reviewed licensee corrective actions associated with vessel head replacement as documented in inspection report No. 50-346/02-07. However, an outstanding Checklist item No. 2.a related to NRC reviews of the reactor vessel head replacement was open as of September 2003, pending NRC review of the final acceptance testing of the replacement vessel head.

<u>Analysis:</u> The finding described above is the result of a licensee performance deficiency. Specifically, the licensee failed to properly implement the boric acid corrosion control and corrective action programs, which allowed the reactor coolant system pressure boundary leakage to occur undetected for a prolonged period of time. The risk significance of this finding was evaluated by the NRC and determined to be of high safety significance (in the Red range) as documented by the NRC in inspection report 50-346/03-16 dated May 29, 2003.

<u>Enforcement:</u> In NRC report 50-346/02-08, the inspectors identified ten Unresolved Items for licensee performance deficiencies associated with CRDM cracking and head degradation. On May 29, 2003, the NRC completed a final determination of the risk and characterized these ten unresolved items as apparent violations (NRC inspection report 50-346/03-16). Specifically, the NRC identified:

- an apparent violation of Technical Specification Limiting Condition for Operation for Reactor Coolant System Operational Leakage, paragraph 3.4.6.2, for operation of the plant with pressure boundary leakage from through-wall cracks in the reactor coolant system;
- an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI involving failure to take adequate corrective action for a continuing buildup of boric acid deposits on the reactor head;
- an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI involving failure to take adequate corrective action for recurrent accumulations of boric acid on containment air cooler (CAC) fins;

- an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI involving failure to take adequate corrective action for repeated clogging of radiation element filters, although a sample of the filter deposits revealed iron oxides, and radionuclides indicative of reactor coolant;
- an apparent violation of 10 CFR Part 50, Appendix B, Criterion V involving the failure to follow the corrective action procedure and take timely corrective action to implement a modification to permit complete inspection and cleaning of the reactor vessel head and CRDM nozzles;
- an apparent violation of 10 CFR Part 50, Appendix B, Criterion V involving the failure to follow the corrective action procedure and implement an effective corrective action for adverse trends in reactor coolant system unidentified leakage;
- an apparent violation of 10 CFR Part 50, Appendix B, Criterion V involving the failure to establish a procedure appropriate to the circumstances in that deficiencies in the procedure NG-EN-00324, "Boric Acid Corrosion Control Program," Revisions 0 through 2 contributed to the failure to detect and address corrosion of the reactor head;
- an apparent violation of 10 CFR Part 50, Appendix B, Criterion V involving the failure to remove boric acid deposits and inspect the base metal of the reactor head as directed by NG-EN-00324, Revision 2, "Boric Acid Corrosion Control Program";
- an apparent violation of 10 CFR Part 50, Appendix B, Criterion V involving the failure to properly characterize CRs 2000-0782 and 2000-1037 as significant conditions adverse to quality, in accordance with the guidance contained in the licensee's corrective action program procedure; and
- an apparent violation of 10 CFR Part 50.9 involving the failure to provide complete or accurate information material to the NRC associated with nine documents including work orders, condition reports, audit report and licensee letters to the NRC associated with boric acid deposits on the vessel head.

On May 29, 2003, the NRC issued the Final Significance Determination letter for a Red finding associated with control rod drive mechanism penetration cracking and reactor pressure vessel head degradation. The safety significance is one of the inputs into the final characterization and resolution of the apparent violations described in the Augmented Inspection Followup Report dated October 2, 2002. The NRC's investigation into the cause of those apparent violations, which were referred to the Office of Investigations, is ongoing. The results of that investigation will be factored into the final enforcement deliberations. As a result, no Notice of Violation is attached at this time. The number and nature of those violations could change as a result of further NRC review. The licensee documented the investigation and corrective actions for the head degradation in condition reports 2002-00891, 2002-00932, 2002-01053, and 2002-01128.

Based on the licensee's root cause report and associated corrective actions, as well as the NRC's 0350 Panel's monitoring of licensee performance improvement through the Restart Checklist, LER 2002-002 is considered closed.

.3 <u>(Closed) Licensee Event Report (LER) 50-346/03-008-00</u>: Relays Installed in Safety Features Actuation System with Insufficient Contact Voltage Ratings

a. <u>Inspection Scope</u>

The inspectors reviewed LER 2003-008-00, which documented a condition where the licensee installed five relays in to the Safety Features Actuation System (SFAS) which were not rated for that application.

b. <u>Findings</u>

<u>Introduction</u>. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, having very low safety significance for failing to identify the appropriate corrective actions to address all significant causal factors related to the configuration control aspects associated with the installation of unqualified relays in the SFAS system. This issue was considered NRC-identified because, even though two root cause evaluations were completed for two separate Significant Conditions Adverse to Quality (SCAQ) condition reports related to this issue (Technical Evaluation of Output Relay Issues for the Safety Features Actuation System (SFAS) (CR 03–02725), and Procurement of SFAS Relays (CR 03-03232)), neither evaluation addressed the configuration control aspects of the problem. Namely, how the five deficient generation 3 relays had been installed, prior to refueling outage 13.

<u>Description</u>. On July 8, 2003, with the plant shutdown in Mode 5, the licensee discovered that five Generation 3 SFAS relays had been installed in the SFAS during a time period when SFAS was required to be operable. These relays had been installed between May 2, 2001, and November 6, 2001, and remained in operation until the beginning of the refueling outage on February 16, 2002. The installation of these relays facilitated the operation of the following components:

- CV5010E (Containment Hydrogen Analyzer 2 Discharge Valve);
- CV5076 (Containment Vacuum Relief Isolation Butterfly Valve);
- RC240B (Pressurizer Sample Line Isolation);
- P43-3 (Component Cooling Water Pump 3); and
- SC1530 (Containment Spray Auto Control Valve 1).

This issue, which discussed the misapplication of the Generation 3 SFAS relays, was initially documented in Inspection Report 50-346/03-013. That report documented a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, for the failure to properly implement procedures required for performing equivalency evaluations for components being replaced in safety related equipment. This resulted in the installation of relays (Generation 3 relays) into the Safety Features Actuation System cabinets that were not electrically rated for that specific application. At that time, the licensee believed that no Generation 3 relays had been installed in the SFAS system during any operational Mode that required SFAS to be operable. As part of the licensee's corrective actions to address this issue, two SCAQ condition reports were generated; the first dealt with the technical evaluation of the SFAS relay issue (CR 03-02725), the second dealt with the replacement relay procurement issue (CR 03-3232). Each of these condition reports generated a root cause report and several corrective actions.

Neither evaluation addressed the configuration control aspects of how five generation 3 relays managed to be installed, prior to refueling outage13.

On July 8, 2003, the licensee identified that five of the generation 3 relays had been installed prior to the beginning of refueling outage 13. Again, a SCAQ condition report (03-05402) was generated to document the issue. The root cause analysis report associated with the condition report sufficiently discussed how a single common cause (the improper procurement of replacement relays) could potentially render individual trains of SFAS incapable of performing its safety function. Again, the issue of how these five relays came to be installed and remained installed in the SFAS system for an extended period of time, without the cognizant engineer's knowledge, was not addressed.

Analysis. In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP Phase 1 screening and determined that the issue affected the Reactor Safety Strategic Performance Area. The finding was more than minor because it: (1) involved the configuration control attribute of the Mitigating Systems Cornerstone; and (2) affected the cornerstone objective to ensure the availability, reliability, and capability of the systems that respond to initiating events to prevent undesirable consequences. This finding was of very low safety significance because none of the five relays were installed in redundant channels, therefore the redundant SFAS actuated component remained capable of performing its designated safety function.

Enforcement. The performance deficiency associated with this issue is that the licensee failed to address all significant causal factors related to the configuration control aspects associated with the installation of unqualified relays in the SFAS system. Criterion XVI, "Corrective Action," of Appendix B to 10 CFR Part 50, states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to the above, the licensee failed to take effective corrective actions to fully address the cause of the condition, namely, addressing the configuration control aspect of how five unqualified relays remained installed in SFAS for an extended period of time without the applicable engineer's knowledge. Because of the very low safety significance, and because this issue was entered into the licensee's corrective action program, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000346/2003018-04). The licensee entered this issue into their corrective action program as CR 03-08556. This LER 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; and
- 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's 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 areas:

- performance of plant activities, including maintenance activities;
- follow-up of specific Oversight Panel Technical issues;
- licensee performance during restart readiness meetings;
- licensee performance in categorizing, classifying, and correcting deficient plant conditions during the restart process;
- licensee performance at meetings associated with work backlogs, including 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 <u>Inadequate Procedural Guidance Regarding the Implementation of the Immediate Action Maintenance Process</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the licensee documentation that was currently available that outlined the implementation and performance of the Immediate Action Maintenance (IAM) Process.

b. <u>Findings</u>

<u>Introduction</u>. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, having very low safety significance. The violation was identified when the inspectors discovered that procedural guidance which governed the performance of the IAM Process did not exist.

Description. On September 23, 2003, the licensee implemented the IAM process to affect an adjustment of the 1 turbine driven auxiliary feedwater pump governor. This process was discussed in four licensee procedures as follows:

- DB-OP-00000, "Conduct of Operations," Revision 06
  Step 6.16.2, stated, in part, that "the shift manager has the authority and responsibility to perform immediate actions to mitigate failures that potentially threaten public or personnel health or reactor safety. Documentation of actions taken may occur after the fact. This is defined as Priority 100 - Emergency in NOP-WM-4002."

- NOP-WM-4002, "Repair Identification and Toolpouch Maintenance," Revision 1
  Step 3.4 defined Priority 100 as a condition which is an immediate or imminent threat to nuclear safety or personnel/public safety. Resources are worked 24 hours per day to achieve completion at the earliest possible time.

- DB-MN-00001, "Conduct of Maintenance," Revision 10
  Step 6.1.1.a states that "Immediate Action or Immediate Notifications are required as follows: the SM [shift manager]/ SE [shift engineer] has the authority and responsibility to direct Maintenance personnel to perform an Immediate Action necessary to mitigate failures that potentially threaten public and personnel health or reactor safety in accordance with DB-OP-00000 and NOP-WM-4002."

- DB-DP-00007, "Control of Work," Revision 05
  Step 2.2.5 states that "the SM/SE has the authority and responsibility to direct Maintenance personnel to perform an immediate action necessary to mitigate failures that potentially threaten public and personnel health or reactor safety (see NOP-WM-4002, Priority 100 Maintenance).

The IAM process, by design, bypassed many of the normal checks and balances contained within the normal licensee work control process. The net result was a process which expedited emergent maintenance on components that were required to minimize an immediate threat to nuclear safety or personnel/public safety. The inspectors determined that, although several licensee procedures discuss the fact that Operations has the authority to authorize work utilizing the IAM process under very specific conditions, there was no procedural guidance on how the expedited maintenance was controlled, reviewed, or tested, which verified the adequacy of the maintenance activity.

Analysis. In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP Phase 1 screening and determined that the finding was more than minor because if left uncorrected the finding would become a more significant safety concern. This finding was of very low safety significance because, even in the absence of procedural guidance on how to implement the IAM process, the correct technical procedures were utilized to adjust the 1 turbine driven feedwater pump governor and the appropriate retests were performed to evaluate the adequacy of the maintenance.

Enforcement. The performance deficiency associated with this issue is that the licensee failed to provide procedural guidance on how to perform maintenance utilizing the Immediate Action Maintenance process. Criterion V, “Instructions, Procedures and Drawings," of Appendix B to 10 CFR Part 50, 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. Contrary to the above, the licensee failed to provide procedural guidance on how maintenance performed utilizing the Immediate Action Maintenance process was controlled, reviewed, or tested, to verify the adequacy of the maintenance activity. Because of the very low safety significance, and because this issue was entered into the licensee’s corrective action program, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000346/2003018-05). The licensee entered this issue into their corrective action program as CR 03-08776, CR 03-08622, and CR 03-08791.

.2 Improper Application of the Conduct of Operations Procedure Steps Pertaining to the Immediate Action Maintenance Process

a. Inspection Scope

The inspectors reviewed the implementation of the Immediate Action Maintenance Process used to perform adjustments of the 1 turbine driven feedwater pump governor during the normal operating pressure test.

b. Findings

Introduction. The inspectors identified a Non-Cited Violation of Technical Specification 6.8.1.a having very low safety significance when the inspectors identified the improper application of DB-OP-00000, “Conduct of Operations,” Revision 06, pertaining to the implementation of the Immediate Action Maintenance (IAM) process.

Description. On September 23, 2003, the Shift Manager utilized the Immediate Action Maintenance process to affect adjustments on the auxiliary feedwater pump 1 governor.

Procedure DB-OP-00000, “Conduct of Operations,” Revision 06, step 6.16.2, states, in part, that “the shift manager has the authority and responsibility to perform immediate action to mitigate failures that potentially threaten public or personnel health or reactor safety. Documentation of actions taken may occur after the fact. This is defined as Priority 100 - Emergency in NOP-WM-4002. Examples are provided in Attachment 4.” Attachment 4 specified that the “Shift Manager may authorize IAM if a maintenance work order cannot be made available in time and one or more of the following conditions apply:

- imminent plant trip, power reduction, or shutdown;
- forced entry into a Technical Specification action statement which requires specific action within 24 hours or less;
- major personnel safety or equipment hazard;

- fire protection related equipment is declared inoperable and requires one or more continuous fire watches or addition of pumping equipment to be established;
- degraded plant chemistry that is significantly out of specification;
- degraded radiological conditions;
- generation of excessive amounts of radioactive waste; and/or
- significant operator burden that may be a hazard to safe operation."

The inspectors discovered the following during their inspection of the licensee's implementation of the IAM process to adjust the governor on the 1 turbine driven auxiliary feedwater pump:

- Several of the examples listed in Attachment 4 of DB-OP-00000, "Conduct of Operations," Revision 06, such as entry into a TS action statement, are not required to ensure reactor safety or protect the health and safety of the public. This was contrary to the reasons for implementing the IAM process as stated in DB-OP-00000, "Conduct of Operations," Revision 06, DB-MN-00001, "Conduct of Maintenance," Revision 10, and DB-DP-00007, "Control of Work," Revision 05.

- There was no immediate threat to the public health or reactor safety caused by the slightly slower response time of auxiliary feedwater pump 1.

- Contingency [work] Order 200045588 had been prepared and was available for use at the time IAM was authorized to affect the governor adjustment. The problem description on the work order stated: "This notification is made to create a FIN (Fix-It-Now) order to perform Auxiliary Feedwater Pump Turbine #1 governor adjustments if the need to do so is determined while performing required surveillance testing during plant heatup and the NOT/NOP test. Adjustments to be made as per DB-MM-09098."

<u>Analysis</u>. In accordance with IMC 0609, Appendix A, Attachment 1, the inspectors performed a SDP Phase 1 screening and determined that the finding was more than minor because if left uncorrected the finding would become a more significant safety concern. As stated in a number of the licensee procedures, the IAM process should only be implemented to affect maintenance required to mitigate failures that potentially threaten public or personnel health or reactor safety. The expedited nature of the IAM process was derived from the performance of the normal work reviews and documentation, after the maintenance is performed. As a result, the potential for errors associated with the work performed under the IAM process and the adequacy of the retest to validate the effectiveness of the maintenance, was increased. This finding was of very low safety significance because the actual impact of the inappropriate implementation of the IAM did not adversely impact the adjustment of the 1 turbine driven feedwater pump governor and an adequate retest was performed to evaluate the adequacy of the maintenance.

<u>Enforcement</u>. The performance deficiency associated with this event is the senior operations management inappropriately authorized the performance of the Immediate Action Maintenance process to perform adjustments on 1 turbine driven auxiliary

feedwater pump governor. Technical Specification 6.8.1.a requires implementation of procedures required by Regulatory Guide 1.33. Regulatory Guide 1.33 requires, in part, procedures for performing maintenance that can affect the performance of safety-related equipment. The licensee developed DB-OP-0000, “Conduct of Operations,” Revision 06, a safety related procedure, to, in part, provide guidance on how Operations personnel expedite maintenance required to mitigate failures of equipment that potentially threaten public or personnel health or reactor safety. Step 6.16.2, states, in part, that the shift manager has the authority and responsibility to perform immediate action to mitigate failures that potentially threaten public or personnel health or reactor safety. Additionally, Attachment 4 of this procedure provides further guidance, in part, that the Shift Manager may authorize IAM if a maintenance work order cannot be made available in time. Contrary to these requirements, there was no immediate threat to the public health or reactor safety caused by the slightly slower response time of auxiliary feedwater pump 1, and at the time the Immediate Action Maintenance was authorized, a contingency [work] Order was available to perform the governor adjustment. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program, it is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000346/2003018-06). The licensee entered this issue into their corrective action program as CR 03-08776, CR 03-08622, and CR 03-08791.

.3 Conduct of Operations Performance Issues

a. Inspection Scope

The inspectors reviewed a number of issues, not previously discussed in this report, which involved operator performance or procedure quality.

b. Findings

The issues reviewed by the inspectors included:

- On September 3, 2003, while performing Section 4.2 of DB-PF-03080, “AFW Check Valves AF1, AF2, AF15, and AF 16 Reverse Flow Tests,” Revision 00, the initial system conditions, using the guidance stated in the procedure, could not be established to perform the test. To correct this condition, the test leader attempted to vent the upstream pressure seen by the valves. Steps for this venting were not in the procedure and the specific approval was not obtained from control room staff prior to manipulating the vent valves. When this effort was unsuccessful the test leader terminated the test. The inspector identified that the procedure was a “step by step” procedure and that the personnel performing the surveillance, by attempting to vent the piping, had deviated from the procedure without prior approval.

  This was determined to be a minor violation of Technical Specification of 6.8.1.a. Specifically, procedure DB-PF-03080, “AFW Check Valves AF1, AF2, AF15, and AF 16 Reverse Flow Tests,” Revision 00. This issue did not rise to the level of more than minor significance because the auxiliary feedwater system was not currently aligned for operation and maintenance and testing of the system was ongoing. This issue was considered to be a violation of minor significance and was not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee documented this issue in their corrective action program (CR 03-07262).

- On September 22, 2003, while attempting to establish additional turbine plant cooling water flow through the generator hydrogen coolers utilizing procedure DB-OP-06263, "Turbine Plant Cooling Water System," Revision 03, a spill of approximately 80 gallons occurred due to vent and drains valves associated with the generator hydrogen coolers being inappropriately left open.

  The inspectors determined this to be a minor violation of Technical Specification 6.8.1.a. Specifically, procedure DB-OP-06263, "Turbine Plant Cooling Water System," Revision 03, was a step-by-step procedure. In completing the steps, the procedure required verification that the system had been placed in service including verification of system valve lineup. The valve verification sheets specified that the vents and drain should be closed for system operation. This issue did not rise to the level of more than minor significance because the impact of the water loss did not affect the operation of the turbine plant cooling water system nor did the leakage impact the operation of any risk-significant equipment. This issue was considered to be a violation of minor significance and was not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee documented this issue in their corrective action program (CR 03-07930).

- On September 5, 2003, during a plant heatup to establish test conditions for the reactor coolant system normal operating test, CF1B opened unexpectedly when reactor coolant system pressure increased to the valves automatic actuation setpoint.

  This was determined to be a minor violation of Technical Specification of 6.8.1.a. Specifically, Procedure DB-OP-06900, "Plant Heatup," Revision 15, was deficient because, due to the differences in tolerances between the pressure instruments that monitor loop 1 RCS pressure, loop 2 RCS pressure, and SFAS channel 3 RCS pressure, it was unlikely that the reactor operator could establish the prescribed pressure band for the CF1A and CF1B interlock testing sequence (675 to 700 psig) without also reaching the actuation setpoint for CF1B. This was considered to be a violation of minor significance and not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This issue is discussed further in Section 4OA3.1 of this report.

As a result of the trend of Operations events and errors that occurred during this reporting period, the licensee generated a significant condition adverse to quality condition report (CR 03-08418) and will be completing a root cause investigation regarding this issue.

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

The resident inspectors continued to monitor the licensee's 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 4. To accomplish this, the inspectors:

- attended and assessed licensee management meetings;
- monitored the management of open Mode 4 and 3 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 condition reports, prioritization of work activities, and setting of work completion dates took place.

The inspectors attended several Plant Support Center Meetings. The purpose of these meetings was to status significant restart equipment issues and focus licensee resources to efficiently and effectively work activities to provide more realistic work completion schedules.

The inspectors attended various work planning meetings. During the meetings there were discussions among the planners, workers, and management on the approaches needed to correct equipment issues.

No significant issues were identified.

4OA6 Meetings

The inspectors presented the inspection results to Mr. Lew Myers, and other members of licensee management on October 7, 2003. A re-exit was held on October 28, 2003, with M. Bezilla to discuss changes in two findings since the October 7 exit. The licensee acknowledged the findings presented. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee Personnel

M. Bezilla, Site Vice President
G. Dunn, Outage Manager
R. Fast, Director, Organizational Development
J. Grabnar, Manager, Design Engineering
J. Hagan, Senior Vice President, FENOC
L. Myers, Chief Operating Officer, FENOC
K. Ostrowski, Manager, Regulatory Affairs
J. Powers, Director, Nuclear Engineering
M. Roder, Manager, Plant Operations
R. Schrauder, Director Support Services
M. Stevens, Director, Maintenance

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

| | | |
|---|---|---|
| 05000346/2003018-01 | NCV | Technical Specification 3.5.2 - Inadequate Final Containment Inspection (Section 1R20.1) |
| 05000346/2003018-02 | NCV | Procedure for Testing the Response Time of the Auxiliary Feedwater Pump 1 Turbine Did Not Adequately Describe the Acceptance Criteria for Successful Completion of the Test (Section 1R22.2) |
| 05000346/2003018-03 | NCV | Control Room Staff Did Not Adequately Monitor and Control Reactor Coolant System Pressure Which Resulted in CF1B Opening Unexpectedly (Section 4OA3.1) |
| 05000346/2003018-04 | NCV | Failure to Address All Significant Causal Factors Related to the Configuration Control Aspects Associated With the Installation of Unqualified Relays SFAS (Section 4OA3.3) |
| 05000346/2003018-05 | NCV | No Procedural Guidance for Performing Immediate Action Maintenance |
| 05000346/2003018-06 | NCV | Improper Implementation of the Immediate Action Maintenance Process |

Closed

| | | |
|---|---|---|
| 50-346/02-002-00 | LER | Reactor Coolant System Pressure Boundary Leakage Due to Primary Water Stress Corrosion Cracking of Control Rod Drive Mechanism Nozzles and Reactor Pressure Vessel Head Degradation |
| 50-346/03-008-00 | LER | Relays Installed in Safety Features Actuation System with Insufficient Contact Voltage Ratings |

## LIST OF DOCUMENTS REVIEWED

1R04 Equipment Alignment

DB-OP-06011; High Pressure Injection System; Revision 06

Operational Schematic OS-003; High Pressure Injection System; Rev. 21

Operational Schematic OS-021, Sheet 1; Component Cooking Water System; Rev. 30

1R05 Fire Protection

Fire Hazards Analysis Report

Fire Protection Schematic A-221F; Rev. 7

1R11 Licensed Operator Requalification Program

DB-OP-06900; Plant Heat Up; Revision 14

1R12 Maintenance Effectiveness

DB-PF-0003, Maintenance Rule; Revision 4

Maintenance Rule Program Manual; Revision 10

Service Water Loop 2 Partial Integrated Flow Balance Test data as collected by DB-SP-03001; August 18 - 22, 2003

CR 03-06845; Maintenance Rule (a)(1) Eval for Service Water System Exceeding Performance Criteria

CR 03-05147; Inadvertent Closure of SW 139

CR 03-06317; Documentation of Failure of PSL 1376A, Service Water Pump 1 Low Pressure Switch

CR 03-07524; Service Water Train 2 Flow Less than Flow Balance Acceptance Criteria

1R13 Maintenance Risk and Emergent Work

Contingency Plan 13RFO-33; Work with Decay Heat Pump #2 Running with Work on HPI Pump #2 Minimum Recirculation Modification in ECCS Room # 2; Revision 1; dated August 25, 2003

Regulatory Applicability Determination 03-02037 for CR 03-08108; Bypass of Steam Traps Associated with Main Stm LN to Aux Feed Pump Turbine 1-1 Steam Line; Revision 0

Operability Evaluation 03-0033; Delay Time for MS-5889B

Problem Solving Plan for CR 03-07975 and 03-08108; Surveillance Test Failure: Auxiliary Feedwater Pump #1 Response Time <40 Seconds

WO 200045588; AFPT #1 Governor; Adjust per DB-MM-09098 if Needed

DB-MM-09098; AFPT Governor Maintenance; Revision 04

Problem Solving Plan; CR 03-07794, Containment Spray Pump 1 Breaker Tripped; Revision 03

Problem Solving Plan; CR 03-07352; CS Pump 1 Motor Trip

CR 03-07794; Ctmt Spray Pump 1 Breaker BE111 Tripped Free Upon Start

CR 03-05464; CS Pump 2 Motor Trip

CR 03-07351; Ctmt Spray Pump 1 Failed to Start

CR 03-07608; Containment Spray Pump #2 Tripped Immediately When Started

ECR 03-0513-00; Eliminate the Ground Fault Trip Feature on SST (Solid State Trip) Unit for Circuit Breaker Installed in BE111

CR 03-07904; SFAS Ch 3 RCS Lo Lo Pressure Trip

CR 03-07914; Service Water Pump Strainer Motor Did Not Trip in Overload Condition

1R14 Personnel Performance During Nonroutine Plant Evolutions

DB-OP-06900; Plant Heat Up, Revision 15, 16, and 17

CR 03-07726; High Seal Return Temperature on RCP 2-2

CR 03-07718; Excessive Leakby Through SP7B, Startup Feedwater Valve #1

CR 03-07710; Banging Noise in Steam Line 2

CR 03-07713; Personnel Air Lock Failure

CR 03-07904; SFAS CH 3 RCS Low Pressure Trip

CR 03-07919; Gray Boot Connectors

CR 03-07879; Aux Feedwater System Train 1 Low Steam Pressure Interlock Test Failure

1R15 Operability Evaluations

Evaluation of 3/8" x 2.5" Stem-to-Disc Pins and Disc Seat Fragments from DH13B/DH14B Potentially in the Reactor Coolant System; dated September 7, 2003

CR 03-07037; Missing Taper Pins

CR 03-07049; Disc Pins May Have Entered the RCS

DH14B Loss of Disc Pins Problem Solving Plan; dated September 3, 2003

Operability Evaluation 2003-027; Service Water Train 2 Flow Less Than Flow Balance Acceptance Critieria; Revision 00

CR 03-07524; Service Water Train 2 Flow Less Than Flow Balance Acceptance Criteria

CR 03-07609; SW 2 Baseline Testing Data Needs Evaluation

CR 03-06651; Containment Air Cooler #1, #2, and #3 Bellows Assembly

Operability Evaluation 2003-024; Containment Air Cooler 2 and 3 Evaluation; Revision 00

Operability Evaluation 2003-016; Battery Support Plate Rods; Revision 00

Operability Evaluation 2003-016; Battery Support Plate Rods; Revision 01

CR 03-05984; Follow-Up to CR 03-05842, Battery Plate Support Rods

CR 03-06846; Station Batteries 2P and 2N Compliance With TS 4.8.2.3.2.c.1

Institute of Electrical and Electronics Engineers Standard 450-1995; IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications

Operability Evaluation 2003-013; Preliminary Davis-Besse AC System Analysis Results Rev. 1

Operability Evaluation 2003-022; Replace SW/CCW Time Delay Relays in AC101 and AD101 Rev. 0

CR 03-04435; Preliminary D-B AC System Analysis Results

CR-03-07252; QA Identified Deficiencies in ECR 03-0338

CR 03-06253; Tracking CR: Update Sump Strainer Calculation for Adjusted Debris Loading

CR 03-06406; Containment Lighting/Sump Loading

CR 03-07399; Evaluation of Test/Camera Equipment Left in Containment for Mode 3

Operability Evaluation 2003-029; Impact on Decay Heat Pump 1 and Containment Spray Pump 1 and Suction Piping from Pressurization by the Core Flood Tank

1R20 Refueling and Outage

CR 03-07628; Items Identified During Containment Closeout

DB-OP-06900; Plant Heatup; Revision 15

1R22 Surveillance Testing

DB-SP-03218; HPI Train 1 Pump and Valve Test; Revision 06

DB-SP-03155; AFW Train 1 Flow Path to SG Verification; Revision 03

DB-SC 03114; SFAS Integrated Time Response Test; Revision 05

CR 03-07599; Non-Conservative SFAS Time Response Measurements for Certain MOVs

CR 03-07746; Inadvertent Opening of CF1B

DB-OP-0000; Conduct of Operations; Revision 6

Problem Solving and Decision Making Plan; CF1B Opened During Heatup (CR 03-07746)

DB-OP-06900; Plant Heatup; Revision 15, Revision 16, and Revision 17

Operability Evaluation 2003-029; Impact of CF1B Opening on Decay Heat Train 1 and Containment Spray Train 1

CR 03-08108; AFW Train 1 Response Time Test Failure

DB-OP-0002; Operations Section Event/Incident Notifications and Actions; Revision 10

DB-SC–3255; SFRCS Overall Response Time Calculations; Revision 03

CR 03-08067; Improvements to AFW Response Time Testing, DB-SP-03157 and DB-SP-08067

DP-SP-03152; AFW Train 1 Level Control, Interlock and Flow Transmitter Test; Revision 07

CR 03-07548; MS106 Did Not Close on a Low Suction Pressure Actuation

CR 03-07582; Split Fuse Barrel

CR 03-07879; Aux Feedwater System Train 1 Low Steam Pressure Interlock Test Failure

Problem Solving Plan; CR 03-07879, Blown Fuse in the STM Suction Interlocks for MS 106 and MS 106A; Revision 0

CR 03-07262; Venting Performed Outside DB-PF-03080 Steps

DB-PF-03080; AFW Check Valves AF1, AF2, AF15, and AF16 Reserve Flow Tests; Revision 0

DB-SP-03001; Service Water Loop 2 Integrated Flow Balance Procedure, Revision 4

DB-SC-03271; Control Rod Drive Program Verification, LU 03-1325

CR 03-08067; Improvement to AFW Response Time Testing; DB-SP-03157 and DB-SP-03166

DB-SP-03157; AFP1 Response Time Test; Revision 05

## 4OA2 Problem Identification and Resolution

CR 03-04375; Potential Current Overloads on Load Center Breakers

CR 03-04158; SW1424/1429/1434 Valves do not have Accumulators

CR 03-07439; Auxiliary Feedwater Pump did not Start

CR 03 06779; Operability Evaluation Revision Request

CR 03-06798; Operability Evaluation Revision Requested for 2003-0018

CR 03-07052; Behavior Observation Program Training Enhancement

CR 03-07262; Venting Performed Outside DB-PF-0308 Steps

CR 03-07628; Items Identified During Containment Closeout Tour

CR 03-08232; Observations By NRC Inspector

4OA3 Event Followup

CR 03-08556; Timeliness Issue Communicating Past Operability of SFAS

CR 03-07746; Inadvertent Opening of CF1B

Problem Solving and Decision Making Plan for CR 03-07746

CR 03-05402; Five Generation 3 (G3) Relays Found Installed In SFAS Prior to 13RFO

LER 2003-008; Relays Installed in Safety Features Actuation System with Insufficient Contact Voltage Ratings

CR 03-03232; Inadequate Approval of Replacement SFAS Relays

CR 03-02725; New Style SFAS Output Relay Potential Design Deficiency

4OA5 Other Activities

CR 03-07930; TPCW Spill form Generator H2 Cooler

DP-OP-06263; Turbine Plant Cooling Water System; Revision 03

NG-DB-0225; Procedure Use and Adherence; Revision 01

NG-QS-00120; Davis-Besse Supplemental Procedure Requirements/Guidance; Revision 03

CR 03-08609; Failure to Properly Notify the NRC Resident Inspector When AFW Inoperable

CR 03-08418; Operation Events - Collective Significance Review

CR 03-07262; Venting Performed Outside DB-PF-03080

DB-PF-03080; AFW Check Valves AF1, AF2, AF15, and AF16 Reverse Flow Tests," Revision 00

DB-OP-00002; Operations Section Event/Incident Notifications and Actions; Revision 10

DB-OP-00000; Conduct of Operations; Revision 06

NOP-WM-4002; Repair Identification and Toolpouch Maintenance; Revision 1

DB-MN-00001, "Conduct of Maintenance," Revision 10

DB-DP-00007; Control of Work; Revision 05

CR 03-08776; Immediate Action Maintenance (IAM) on #1 Aux. Feedpump Governor not Documented

CR 03-08622; Clarification for Immediate Action Maintenance Requested

CR 03-08791; Discrepancy Between NOP-WM-4002 and DB-OP-00000 on Immediate Action Maintenance

## LIST OF ACRONYMS USED

| | |
|---|---|
| ADAMS | Agency-wide Document Access and Management System |
| AFP | Auxiliary Feedwater Pump |
| AFW | Auxiliary Feedwater |
| AIT | Augmented Inspection Team |
| CCW | Component Cooling Water |
| CFR | Code of Federal Regulations |
| CR | Condition Report |
| CRDM | Control Rod Drive Mechanism |
| ECCS | Emergency Core Cooling System |
| FENOC | FirstEnergy Nuclear Operating Company |
| FME | Foreign Material Exclusion |
| IMC | Inspection Manual Chapter |
| IR | Inspection Report |
| LAR | License Amendment Request |
| LCO | Limiting Condition for Operation |
| LER | Licensee Event Report |
| NCV | Non-Cited Violation |
| NRC | United States Nuclear Regulatory Commission |
| PARS | Publicly Available Records |
| PORV | Pressure Operated Relief Valve |
| RCP | Reactor Coolant Pump |
| RCS | Reactor Coolant System |
| SCAQ | Significant Condition Adverse to Quality |
| SFAS | Safety Features Actuation System |
| SFRCS | Steam Feedwater Rupture Control System |
| SDP | Significance Determination Process |
| SW | Service Water |
| TS | Technical Specifications |
| USAR | Updated Safety Analysis Report |
| WO | Work Order |