May 4, 2006

EA-03-309
EA-03-214

Mr. Mark B. Bezilla
Vice President-Nuclear, Davis-Besse
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 05000346/2006002

Dear Mr. Bezilla:

On March 31, 2006, 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 April 12, 2006, 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.

The report documents two NRC-identified findings of very low safety significance (Green). One of these findings was determined to involve a violation of NRC requirements. Additionally, licensee identified violations which were determined to be of very low safety significance are listed in this report. However, because of the very low safety significance and because they were entered into your Corrective Action Program (CAP), the NRC is treating these violations as non-cited violations (NCV) consistent with Section VI.A of the NRC Enforcement Policy. If you contest the severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; 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 2.390 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/

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

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

Enclosure: Inspection Report 05000346/2006002
w/Attachment: Supplemental Information

cc w/encl: The Honorable Dennis Kucinich
G. Leidich, President and Chief
Nuclear Officer - FENOC
J. Hagan, Senior Vice President of
Operations and Chief Operating Officer
Director, Plant Operations
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-346
License No:	NPF-3
Report No:	05000346/2006002
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Davis-Besse Nuclear Power Station
Location:	5501 North State Route 2 Oak Harbor, OH 43449-9760
Dates:	January 1 through March 31, 2006
Inspectors:	J. Rutkowski, Senior Resident Inspector R. Smith, Resident Inspector J. Giessner, Resident Inspector, Palisades R. Winter, Reactor Inspector J. House, Senior Radiation Specialist M. Holmberg, Reactor Inspector T. Ploski, Senior Emergency Preparedness Analyst J. Jacobson, Senior Reactor Engineer
Approved by:	C. Lipa, Chief Branch 4 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000346/2006002; 1/1/2006 - 3/31/2006; Davis-Besse Nuclear Power Station; Inservice Inspection

This report covers a 13 week period of resident inspection. The inspection was conducted by Region III inspectors and resident inspectors. Two Green findings, one of which was a non-cited violation (NCV), were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 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. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding involving a Non-Cited Violation (NCV) violation of 10 CFR 50.55a(g)4 having very low safety significance for failure to expand the scope of weld examinations after identification of a rejectable flaw in the SG 1-2 main steam nozzle-to-shell weld. As a corrective action, the licensee performed the additional weld examination and entered this issue into the corrective action program.

  This finding is of more than minor significance because it is associated with the Mitigating System cornerstone attribute of “Equipment Performance” and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to perform additional examinations prior to returning the plant to service in April of 2000, placed the plant at an increased risk for operation with undetected cracking which can lead to component failure. This finding is of very low safety significance because the licensee subsequently performed additional magnetic particle examinations during the 2006 refueling outage with no rejectable indications. The inspectors determined that the finding was not suitable for SDP evaluation because the failure to expand the scope did not directly result in degraded or inoperable equipment. Therefore, this finding was reviewed by Regional Management, in accordance with IMC 0612 Section 05.04c, and determined to be of very low safety significance. (Section 1R08)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a finding having very low safety significance for failure to use qualified transducers during ultrasonic examination of a dissimilar metal weld on the pressurizer surge line. As a corrective action, the licensee obtained qualified transducers, repeated the examination, and entered this issue into the corrective action program.

  This finding is of more than minor significance because it is associated with the Barrier Integrity cornerstone attribute of “Reactor Coolant System Equipment and Barrier

Performance," and affected the cornerstone objective to provide reasonable assurance that physical design barriers (reactor coolant system) protect the public from radionuclide releases caused by accidents or events. Absent NRC intervention, the licensee would have relied on this degraded examination, which would have placed this weld at increased risk for undetected cracking, leakage, or component failure. This finding is of very low safety significance because a qualified examination was subsequently performed with no relevant indications detected. The inspectors determined that the finding was not suitable for SDP evaluation because the failure to use qualified transducers did not directly result in degraded or inoperable equipment. Therefore, this finding was reviewed by Regional Management, in accordance with IMC 0612 Section 05.04c, and determined to be of very low safety significance. (Section 1R08)

B. Licensee-Identified Findings

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

At the beginning of the inspection period, the plant was operating at approximately 100 percent power. On February 28, 2006, the plant began a power coast down of approximately 1 percent per day until the commencement of their fourteenth refueling outage on March 6, 2006.

Also during this inspection period, several brief power reductions of less than 10 percent occurred on:

- January 15, 2006, to support main turbine valve testing;
- February 12, 2006, to support main turbine valve testing; and
- February 25-26, 2006, to support main steam safety relief valve testing.

The plant was shutdown for their fourteenth refueling outage for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R04 Equipment Alignment (71111.04Q)

a. Inspection Scope

The inspectors performed a partial walkdown of the following systems to check the operability of redundant trains and components when safety equipment was inoperable. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, walked down control systems components, and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barrier integrity and entered identified problems into the corrective action program.

During the walkdown, the inspectors also evaluated the material condition of the equipment to identify if there were significant conditions not already in the licensee's corrective action system or work order system. The following samples were selected:

- On March 7 and 8, 2006, the inspectors conducted a partial walkdown of emergency diesel generator 2 while emergency diesel generator 1 was tagged out for outage work;
- On February 8, 2006, the inspectors conducted a partial walkdown of the containment spray system train 1 during containment spray system train 2 corrective maintenance activities on February 7-9, 2006; and

- On March 16 and 17, 2006, the inspectors conducted a partial walkdown and valve alignment check of valves in the containment pressure boundary that were previously aligned for local leak rate testing to check that these valves were realigned properly for refueling operations.

This constitutes three samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection inspections focused on the availability, accessibility, and condition of fire fighting equipment, the control of transient combustibles, and the condition and 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, and their potential to impact equipment which could initiate a plant transient. Inspectors checked, as applicable, 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, that emergency lighting packs were functioning, and that fire doors, dampers, and penetration seals appeared to be in satisfactory condition.

The following areas were inspected:

- mechanical penetration room 3 (fire area AB, room 303);
- station black out diesel generator building;
- mechanical penetration room 4 (fire area A, room 314);
- electrical penetration room 2 (fire area DF, room 427);
- emergency core cooling system room 1 (fire area AB, room 105);
- control room normal and emergency ventilation room (fire area HH, room 603);
- emergency diesel generator 2 room (fire area J, room 319); and
- containment annulus (fire are A and AB, rooms 127 east and west)

This constitutes eight samples.

b. Findings

No findings of significance were identified.

.2 Fire Brigade Drill (71111.05A)

a. Inspection Scope

On February 1, 2006, the inspectors observed a fire brigade activation which was in response to a fire sprinkler alarm and subsequent start of the electric fire pump for a sprinkler head discharge in room 501 in the auxiliary building. The inspectors reviewed whether protective clothing/turnout gear was properly donned; the fire area was entered in a controlled manner; response times were within licensee procedural guidelines; sufficient fire fighting equipment was brought to the scene by the fire brigade to properly perform their firefighting duties; and, the fire brigade leader's fire fighting directions were thorough, clear, and effective. The inspectors attended the fire brigade debrief of the event.

This constitutes one sample.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the program for their outage inspection of risk-important containment air coolers (CAC). Specifically, the review included the inspection of CAC 3 after the initial inspection showed partial blockage in a sample of service water tubes. The inspectors observed the physical condition of the CAC 3 during the inspection for blockage due to bio-fouling and rust particles. The inspectors reviewed whether the frequency of inspection was sufficient to detect degradation prior to loss of heat removal capabilities below design requirements; whether the inspection results were appropriately categorized against pre-established engineering acceptance criteria; and whether the licensee had developed adequate acceptance criteria for bio-fouling controls.

This constitutes one sample.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08P)

.1 Piping Systems ISI

a. Inspection Scope

From March 9, 2006 through March 24, 2006, the inspectors conducted a review of the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries. The inspectors selected the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of the inspection procedure, based upon the ISI activities available for review during the onsite inspection period.

The inspectors observed the following two types of nondestructive examination activities to evaluate compliance with the ASME Code Section XI and Section V requirements and to verify that indications and defects (if present) were dispositioned in accordance with the ASME Code Section XI requirements.

- Ultrasonic examination (UT) of three pressurizer system dissimilar metal (DM) welds (RC-PZR-WP-91-W/X, RC-PZR-WP-91-Y/Z, RC-PZR-WP-91-Z/W) on the safety relief nozzle-to-safe end welds located at the top of the pressurizer; and
- Dye penetrant examination of the 3-inch W/X axis relief nozzle-to-safe end weld (RC-PZR-WP-91-W/X) located at the top of the pressurizer.

The inspectors reviewed a Code UT examination from the previous outage with a recordable indication identified on the inner radius of the relief nozzle to upper head weld (RC-PZR-WP-23-W/X), and a Code MT examination from the previous outage on the main steam outlet nozzle to shell weld (SP-SG-1-2-WG-23-W/X) with a recordable surface indication to determine if the licensee's corrective actions and extent of condition reviews were in accordance with the ASME Code requirements.

The inspectors reviewed records of two Code Class 2 pressure boundary field welds, fabricated during replacement of valve MU3 in the makeup system, to determine if the welding acceptance and preservice examinations, (e.g., pressure testing, visual, radiographic records, and weld procedure qualification tensile tests and bend tests) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements.

The inspectors performed a review of ISI related problems that were identified by the licensee and entered into the corrective action program, conducted interviews with licensee staff, and reviewed licensee corrective action records to determine if:

- the licensee had described the scope of the ISI related problems;
- the licensee had established an appropriate threshold for identifying issues;
- the licensee had evaluated industry generic issues related to ISI and pressure boundary integrity; and
- the licensee implemented appropriate corrective actions.

The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the attachment to this report.

The reviews as discussed above constitutes one inspection sample.

b. <u>Findings</u>

b.1 <u>Unqualified UT Examination of a Pressurizer Surge Line DM Weld</u>

<u>Introduction:</u> The inspectors identified a Green finding having very low safety significance for failure to select qualified transducers during UT examination of a DM weld on the pressurizer surge line.

<u>Description</u>: The licensee scheduled examination of several DM welds including the hot leg branch connection-to-pipe DM weld examination at the terminal end of the pressurizer surge line using procedure 54-ISI-829-05 "Manual Ultrasonic Examination of Dissimilar Metal Piping Welds." The licensee performed these examinations to meet the industry program initiative described in EPRI 1010087 "Material Reliability Program; Primary System Piping Butt Weld Inspection; and Evaluation Guideline (MRP 139)." The purpose of this examination was to detect cracking in DM welds which are susceptible to primary water stress corrosion cracking (PWSCC).

On March 11, 2006, the inspectors identified that the licensee contractor had selected unqualified transducers for the examination of the hot leg branch connection-to-pipe 10-inch diameter DM weld, (RC-MK-A-82-FW-54) at the terminal end of the pressurizer surge line. To perform the axial scans on the pipe side of this DM weld, the licensee's contractor had selected 60 and 45 degree L-wave transducers which did not have the correct focal length to meet paragraph 6.7.2 of procedure 54-ISI-829-05. The failure to meet the procedure requirement did not constitute a violation of NRC requirements, because this examination was associated with an industry initiative, and not an NRC requirement or licensee commitment. The licensee used these incorrectly focused transducers during this examination which degraded the capability to detect cracking on the pipe side of this DM weld. The inspectors' questions and concerns prompted the licensee to procure additional qualified transducers with the required focal depth for the pipe side examination. On March 13, 2006, the licensee re-examined the affected portions (e.g., pipe side) of this weld using qualified transducers, and entered this issue into their corrective action system (CR 06-00866). The licensee did not identify any relevant indications during this re-examination.

<u>Analysis:</u> The inspectors determined that the failure of the licensee to use qualified transducers to perform a UT examination of a pressurizer surge line DM weld, was a performance deficiency that warranted a significance evaluation. This finding was of more than minor significance because it was associated with the Barrier Integrity cornerstone attribute of "Reactor Coolant System (RCS) Equipment and Barrier Performance," and affected the cornerstone objective to provide reasonable assurance that physical design barriers (RCS) protect the public from radio nuclide releases caused by accidents or events. Absent NRC intervention, the licensee would have

relied on this degraded examination, which would have placed this weld at increased risk for undetected cracking, leakage, or component failure. Further, the licensee's contractor was scheduled to perform many other DM welds in the RCS, and absent NRC intervention, may have repeated this error. This finding was of very low safety significance because a qualified examination of this surge line DM weld was subsequently performed with no relevant indications detected. The inspectors determined that the finding could not be evaluated using the Significance Determination Process (SDP) in accordance with NRC IMC 0609, "Significance Determination Process," because the SDP applied to degraded systems/components, not to the examination activities intended to detect degraded components. Therefore, this finding was reviewed by a Regional Branch Chief in accordance with IMC 0612, Section 05.04c, who agreed with the inspectors, that this finding was of very low safety significance (Green).

Enforcement: No violation of regulatory requirements was identified, because the licensee performed this examination to meet industry guidelines (MRP-139), and not to meet NRC requirements or licensee commitments. This finding was determined to be of very low risk significance based upon management review (FIN 05000346/2006002-01).

b.2 Failure to Expand Code Weld Examination Scope

Introduction: The inspectors identified a Green finding involving a Non-Cited Violation (NCV) violation of 10 CFR 50.55a(g)4 having very low safety significance for failure to expand the scope of weld examinations after identification of a rejectable flaw in the SG 1-2 main steam nozzle-to-shell weld.

Description: On April 26, 2000, the licensee identified a rejectable linear flaw (0.4-inch in length) in the SG 1-2 main steam nozzle-to-shell weld (SP-SG-1-2-WG-23-W/X) during a magnetic particle (MT) examination. The maximum acceptable flaw length was 0.375-inch in accordance with the ASME Code Section XI Table IWC-3511-2 "Allowable Linear Flaws." The licensee reduced this flaw to an acceptable size (0.34-inch) by removing a small amount of surface material and repeating the MT examination. However, the licensee did not expand the scope of examinations to other main steam nozzle welds during the outage, as required by the ASME Section XI Code. Instead the licensee concluded that, because this flaw was not rejectable after surface conditioning (e.g metal removal), the additional Code weld examination requirements did not apply. The inspector concluded that the licensee failed to follow the Code and expand the exam scope to perform an additional number of examinations equal to 20 percent of those scheduled during the Code interval (e.g., one additional vessel nozzle-to-shell weld was required). On March 29, 2006, the licensee performed an additional examination of SG 1-1 main steam nozzle-to-shell weld (SP-SG-1-1-WG-23-W/X) and entered this issue into their corrective action system (CR 06-01182). The licensee did not identify any relevant indications during this re-examination.

Analysis: The inspectors determined that the failure of the licensee to expand the scope of weld examinations after identification of a rejectable flaw was a performance deficiency that warranted a significance evaluation. This finding was of more than minor significance because it was associated with the Mitigating System cornerstone attribute of “Equipment Performance” and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to perform additional examinations prior to returning the plant to service in April of 2000, placed the plant at an increased risk for operation with undetected cracking which can lead to component failure. This finding was of very low safety significance because the licensee subsequently performed additional MT examinations of a nozzle-to-shell weld during the 2006 refueling outage with no rejectable indications. The inspectors determined that the finding could not be evaluated using the SDP in accordance with NRC IMC 0609, “Significance Determination Process,” because the SDP applied to degraded systems/components, not to the examination activities intended to detect degraded components. Therefore, this finding was reviewed by a Regional Branch Chief in accordance with IMC 0612, Section 05.04c, who agreed with the inspectors, that this finding was of very low safety significance (Green).

Enforcement: On March 14, 2006, while performing the NRC baseline procedure 71111.21, the inspectors identified an NCV of 10 CFR 50.55a(g)4.

10 CFR 50.55a(g)4 required in part that throughout the service life of a boiling or pressurized water reactor facility, components classified as ASME Code Class 1, 2, and 3 must meet requirements of Section XI.

The 1989 Edition, 1991 Addenda of the ASME Code Section XI, Article IWC-2430(a) required in part, examinations that reveal flaws or relevant conditions exceeding the acceptance standards of Table IWC -3410-1 shall be extended to include additional examinations during the current outage. The additional examinations shall include an additional number of welds, areas, or parts for the inspection item equal to 20 percent of the number of welds, areas, or parts included in the inspection item that are scheduled to be performed during the interval.

The 1989 Edition, 1990 Addenda of the ASME Code Section XI, Table IWC-3410-1 “Acceptance Standards,” specified Article IWC-3511 for vessel nozzle welds.

The 1989 Edition, 1990 Addenda of the ASME Code Section XI, Table IWC-3511-2 “Allowable Linear Flaws”, limited a linear flaw length to 0.375-inch for components exceeding 4-inches in thickness.

Contrary to the above, on April 26, 2000, the licensee identified an indication (0.4-inch) in SG 1-2 main steam nozzle-to-shell weld (SP-SG-1-2-WG-23-W/X) which exceeded allowable standards of Table IWC-3511-2, and failed to expand the scope of nozzle weld examinations to include an additional number of welds equal to 20 percent of the number of welds scheduled for the Code interval. Failure to perform the additional examinations during the April 2000 refueling outage as required by the ASME Code Section XI for Code Class 2 components, is a violation of 10 CFR 50.55a(g)4. The finding is not suitable for SDP evaluation, but has been reviewed by NRC Management, and is determined to be a Green finding of very low safety significance. Because of the very low safety significance of this finding, and because the issue was entered into the licensee's corrective action program (CR 06-01182), it is being treated as an NCV, consistent with Section VI.A.1 of the Enforcement Policy (NCV 05000346/2006002-02).

.2 Pressurized Water Reactor Vessel Head Penetration ISI

a. Inspection Scope

The inspectors did not perform a review of this procedure Section (reduction in one inspection sample), because the inspection of this area was instead performed in accordance with Temporary Instruction (TI) 2515/150 "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles."

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

From March 6, 2006, through March 14, 2006, the inspectors reviewed the Unit 2 BACC inspection activities conducted pursuant to licensee commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary."

The inspectors observed the licensee conducting the train 1 ECCS integrated leak test, walked-down the area under RC769 (a relief valve that had leaked during the operating cycle), and other borated systems, and reviewed the licensee's records of BACC visual examinations conducted during DG-PF-03010 "RCS Leakage Test" completed on January 5, 2004, to evaluate compliance with licensee BACC program requirements, and 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. In particular, the inspectors performed this observation and review to determine if the licensee focused BACC inspections on locations where boric acid leaks can cause degradation of safety significant components and to determine if degraded or non-conforming conditions were properly identified in the licensee's corrective action system.

The inspectors reviewed corrective actions and evaluations performed for boric acid found on reactor coolant system connected piping, and components to confirm that corrective actions were consistent with requirements of Section XI of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI, and that the minimum Code required section thickness had been maintained for the affected components sampled by the inspectors.

The documents reviewed during this inspection are listed in the Attachment to this report.

The reviews as discussed constitute one inspection sample.

b. Findings

No findings of significance were identified.

.4 Steam Generator (SG) Tube ISI

a. Inspection Scope

From March 15, 2006 through March 23, 2006, the inspectors performed an on-site review of SG tube examination activities conducted pursuant to Technical Specification (TS) and the ASME Code Section XI requirements.

The NRC inspectors observed acquisition of eddy current (ET) data, interviewed ET data analysts, and reviewed a sample of documents related to the SG ISI program to determine if:

- in-situ SG tube pressure testing screening criteria and the methodologies used to derive these criteria were consistent with the Electric Power Research Institute (EPRI) TR-107620, “Steam Generator In Situ Pressure Test Guidelines”;
- the in-situ SG tube pressure testing screening criteria were properly applied in terms of SG tube selection based upon evaluation of the list of tubes with measured/sized flaws;
- the numbers and sizes of SG tube flaws/degradation identified were bounded by the licensee’s previous outage Operational Assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to identify tube degradation based on site and industry operating experience by confirming that the ET scope completed was consistent with the licensee’s procedures, plant TS requirements and EPRI 1003138, “Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6”;
- the SG tube ET examination scope included tube areas that represent ET challenges such as the tubesheet regions, expansion transitions and support plates;
- the licensee identified new tube degradation mechanisms;
- the licensee implemented repair methods, which were consistent with the repair processes allowed in the plant TS requirements;
- the licensee primary-to-secondary leakage, (e.g., SG tube leakage) was below the detection threshold during the previous operating cycle;
- the licensee initiated evaluations for unretrievable loose parts;
- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, “Performance Demonstration for Eddy Current Examination,” of EPRI 1003138, “Pressurized Water Reactor Steam Generator Examination Guidelines,” Revision 6; and
- the licensee identified any deviations from ET data acquisition or analysis procedures.

The inspectors performed a review of SG ISI related problems that were identified by the licensee and entered into the corrective action program, conducted interviews with licensee staff and reviewed licensee corrective action records to determine if:

- the licensee had described the scope of the SG related problems;
- the licensee had established an appropriate threshold for identifying issues;
- the licensee had evaluated industry generic issues related to SG tube integrity; and
- the licensee implemented appropriate corrective actions.

The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the attachment to this report.

The NRC inspectors concluded that the reviews discussed above did not count as a completed inspection sample as described in Section 71111.08-5 of the inspection procedure, but the sample was completed to the extent possible.

The specific activities which were not available for the NRC inspectors' review to complete the procedure sample, and the basis for their unavailability is identified below.

- Procedure 71111.08, Steps 02.04.a.3 and 02.04.a.4 associated with review of in-situ pressure testing and tube performance criteria were not available for review, because none of the degraded SG tubes examined during the current refueling outage met the screening requirements for pressure testing;
- Procedure 71111.08, Step 02.04.d associated with review of licensee activities for new SG tube degradation mechanisms was not available for review, because no new tube degradation mechanisms were identified; and
- Procedure 71111.08, Step 02.04.h associated with review of corrective actions for primary-to-secondary leakage greater than 3 gallons per day was not available for review because primary-to-secondary leakage was below the minimum detectable threshold during the previous operating cycle.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11Q)

a. Inspection Scope

On February 10, 2006, the inspectors observed an operating crew during requalification training associated with a shift engineer qualification evaluation and attended the post-session licensee critique. The inspectors reviewed crew performance in the areas of:

- clarity and formality of communications;
- ability to take timely action in a safe direction;
- ability to prioritize, interpret and respond to alarms;

- procedure use;
- oversight and direction from supervisors; and
- group dynamics.

Crew performance in these areas was compared to licensee management expectations and guidelines as presented in Davis-Besse operational and administrative procedures. The operational scenario included a reactor coolant system large break with a failure of decay heat pump 1 to start.

This constitutes one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the licensee's handling of material condition issues associated with the fire protection system with primary emphasis on doors and hatches that provided protection barrier functions. The inspection consisted of evaluating the following specific activities:

- the licensee's use of the condition report process and work order notification system in identifying deficiencies and issues with the fire protection system, doors and hatches;
- that short-term corrective actions were appropriate for deficiencies;
- that equipment performance issues were correctly categorized for reliability per the system's scoping sheet performance criteria;
- that goals and corrective actions for the long-term reliability were appropriate;
- that the licensee's corrective actions included extent of condition; and
- that maintenance rule system status classification and current reclassification appeared appropriate for the equipment's recent history.

Additionally the inspectors performed a walkdown of a sample of the fire protection system doors and hatches and discussed future corrective actions with the system engineer.

This constitutes one sample.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed the licensee's controls for risk significant activities. These activities were chosen based on their potential impact on increasing overall plant risk. The inspections were conducted to review whether the planning, control, and performance of the work was done in a manner to control 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 evaluated, that protected equipment had been identified and was being controlled where appropriate, that significant aspects of plant risk were being communicated to the necessary personnel, and that, as necessary, existing work plans were adjusted to accommodate a change in planned equipment operability. The inspectors evaluated the following licensee activities:

- On December 28, 2005, the licensee noted a 40 pound pressure drop in reactor coolant system pressure. Upon investigation the cause of the pressure drop was attributed to the RC2 spray valve cycling open and back closed. The licensee installed online monitoring equipment for the non-nuclear instrumentation cabinet.
- On January 11, 2006, the licensee entered and then exited a 2-hour shutdown limiting condition for operation per TS 3.8.2.3.b. This was due to the DBC-2PN battery charger float voltage being high out of specification.
- On January 20, 2006, the licensee entered a 7-day shutdown limiting condition for operation when they declared the emergency diesel generator 2 inoperable per TS 3.8.1.1.b. This was due to broken parts found in the rocker arm area of the diesel.
- On January 31, 2006, the licensee determined that they had unintentionally entered a yellow risk condition for a level one plant trip initiator for approximately 9 hours when they shifted loads to an alternate 480 VAC bus E3 while they took the F3 bus down for corrective maintenance. This risk condition was not evaluated on the licensee's initial risk evaluation for the work week. This issue is discussed further in Section 4OA7.
- On February 21, 2006, the licensee placed panel 120 VAC YAR on alternate feed to clean and inspect various components including stepdown transformer XYA. The inspectors reviewed the impact of this work and the overall risk assessment for the work week starting on February 21, 2006.
- On March 8 and 9, 2006, the plant was in a planned “orange” condition for shutdown risk for scheduled draining of the reactor coolant system (RCS) to 80 inches above reactor vessel hot leg nozzle centerline.

This constitutes six samples.

b. Findings

One specific issue which involved a licensee-identified violation was noted during the inspectors' review of the maintenance risk assessment and emergent work samples. This license-identified violation is further discussed in Section 4OA7 of this report

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors reviewed licensee logs and procedures, plant computer data and strip charts as appropriate, and licensee performance, to determine if the response was in accordance with plant procedures. The inspectors reviewed the following non-routine events:

- On February 25-26, 2006, the inspectors observed portions of the main steam safety valve testing. The inspectors focused on the licensee's ability to perform the test and the communication interface between the maintenance and operations departments. The inspectors attended the pre-job brief, reviewed the test data, and conducted a post-job walkdown of the valves and checked for proper valve seating.
- On March 9, 2006, the inspectors observed the deep drain of the reactor coolant system to 26 inches above the RPV nozzle for installation of steam generator cold leg nozzle dams. The inspectors focused on the licensee's ability to control this evolution and the communication between the control room and equipment operators in the containment. The inspectors observed operating crew response to an indicated difference between the reactor indicated level and the mass balance of water being drained from the reactor vessel, which included promptly stopping the deep drain down and resolving the issue prior to proceeding with the vessel deep drain down.
- On March 13, 2006, the inspectors observed the initial reactor head lift activity. The inspectors focused on the licensee's control of the evolution and the communications among the members of the lift team and licensee outage organization personnel.
- During the period of January 9, 2006, through March 19, 2006, the inspectors observed licensee's activities associated with moving irradiated and new fuel in the spent fuel pit and from the reactor vessel to the spent fuel pit. The inspectors reviewed the licensee's use of procedures and reviewed portions of the licensee's inspection of both new fuel and irradiated fuel being offloaded from the core. This included visual inspections and, for fuel assemblies with potential leaks as identified by fuel sipping, ultrasonic inspection of fuel rodlets. The licensee's response to fuel handling equipment issues, that developed during the fuel movement activities, was also reviewed by the inspectors.

This constitutes four samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors selected condition reports which discussed potential operability issues for risk significant components or systems or work orders potentially affecting equipment operability. These condition reports, work orders, or operability evaluations were reviewed to determine whether the operability of the components or systems was appropriately supported. The inspectors compared the operability and design criteria in the appropriate sections of the USAR to the licensee's evaluation of the issues to determine whether the evaluations adequately supported the declarations of operability. Where compensatory measures were necessary to support operability, the inspectors determined whether compensatory measures were in place, would work as intended, and were properly controlled.

The following samples were evaluated:

- CR 05-05802, Main Turbine Master Trip Solenoid Valve "A" Failed Trip Test;"
- CR 06-00313, Auxiliary Feedwater Turbine 2 Did Not Respond to Speed Control Signal From the Control Room
- WO 200143364 and WO200143366, Emergency Diesel Generator 1 and 2 Exciter Modifications and Removal of Missile Shields to Facilitate Activities
- CR 06-01136, Emergency Diesel Generator Acceptance Test: DB-SC-10002 Deficiency: Cabinet C3617 Temperature Rise
- CR 05-05472, Fire Protection 5 Year Flow Test Results Do Not Meet Acceptance Criteria

This constitutes five samples.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors evaluated Engineering Change Package 04-0271-00, "Containment Spray System Piping Thermal Pressure Relief Flow Path," as a sample of a permanent plant modification. The inspectors reviewed the modification during and after installation and testing to verify that the design basis, licensing basis, and performance capability of the containment spray system was not degraded by the on-line installation of the modification and specifically that the modification did not adversely impact the ability of the containment spray pumps to provide the flow rate assumed in the design and accident analyses. The inspectors evaluated the licensee's controls to ensure that installation of the modification did not place the plant in an unsafe condition. Additionally the inspectors reviewed procedures specified in the design package to determine if the procedures had been revised to address new testing requirements necessitated by the design change.

This constitutes one sample.

b. Findings

No findings of significance were identified

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed post-maintenance testing activities to ensure that the testing adequately verified system operability and functional capability with consideration of the actual maintenance performed. The inspectors referenced the appropriate sections of the TSs, the USAR, as well as the documents listed at the end of this report, to evaluate the scope of the maintenance and check that the work control documents required sufficient post-maintenance testing to adequately demonstrate that the maintenance was successful and that operability was restored. The inspectors observed and evaluated test activities associated with the following samples:

- post maintenance testing of emergency diesel generator 2 on January 13, 2006, after 6-year preventive maintenance activities were performed;
- testing of reactor protection channel 1 on January 18 and 19, 2006, after replacement of a buffer amplifier module board (RPS1RC1504) that also required replacement of several capacitors mounted on the board;
- post maintenance testing of auxiliary feedwater turbine 1 on February 7, 2006, after governor oil replacement; and
- post maintenance testing of anticipatory reactor trip system channel 3 on February 22, 2006, after replacement of a pressure switch snubber and repair of leaking tubing.

This constitutes four samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors observed activities associated with the Davis-Besse fourteenth cycle refueling outage which began on March 6, 2006. The inspectors reviewed the reactor coolant system (RCS) cooldown rate, configuration management, clearance activities, reduced RCS inventory operations, shutdown risk management, conformance to applicable procedures, and compliance with TSs. The following major activities were also observed:

- reactor coolant system cooldown and the transition to placing the decay heat removal system into service;
- efforts associated with the planned reactor coolant system corrosion product release and cleanup following the shutdown of the reactor;
- operations with the reactor coolant system in reduced inventory conditions, up to and including deep drain operations (reactor vessel water level below vessel flange level to 26 inches above the hot leg nozzle centerline);
- disassembly of reactor coolant pump 2-1 and 2-2 for replacement with refurbished motors and pumps
- disassembly of the main turbine for maintenance activities associated with the front standard and for replacing the low pressure turbine rotors with a monoblock design;
- removal of the reactor head and internal plenum to permit refueling operations and placement of the items on their refueling stands; and
- reactor core full off-load activities followed by reactor core reload activities.

All the activities associated with refueling and outage activities constitute 1 sample.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed the surveillance test and/or evaluated test data to determine whether the equipment tested met TSs, the 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 determine whether: the test met the TS frequency requirements; the test was conducted in accordance with the procedures, including establishing the proper plant conditions and prerequisites; the test acceptance criteria were met; and the results of the test were properly reviewed and recorded. The following surveillances were evaluated:

- DB-SP-03219, the quarterly inservice testing of the high pressure train 2 pump and related valve test (January 10, 2006);
- DB-MI-03212, the monthly channel functional test of the steam feed rupture control system actuation channel 2 logic (January 10, 2006);
- DB-MI-03246, the monthly channel functional test and device calibration of the steam feed rupture control system steam generator actuation channel 2 level inputs (January 10, 2006);

- DB-MI-03014, the quarterly channel functional test of the reactor protection system's channel 4 trip module logic, anticipatory reactor trip system's channel output logic, and reactor trip breaker C (January 11, 2006);
- DB-SS-03145, the once per refueling interval control room emergency ventilation system test (January 24, 2006);
- DB-SC-04271, the monthly station black out diesel generator test (February 2, 2006);
- DB-SS-04151,the monthly main turbine control valve testing and DB-SS-04152, the monthly main turbine intermediate valve testing (February 12, 2006);
- DB-PF-03011, train 1 emergency core cooling systems integrated leakage testing (February 15, 2006); and
- DB-PF-03008, containment penetration 26 for containment spray local leak rate testing (March 8, 2006).

This constitutes nine samples.

b <u>Findings</u>

No findings of significance were identified.

1R23 <u>Temporary Plant Modifications</u> (71111.23)

a. <u>Inspection Scope</u>

The inspectors reviewed temporary modification 05-0026. The temporary modification addressed a change to the normal service water return flow path to route service water return flow back to the forebay through the discharge piping of service water pump 2.

The inspectors reviewed the temporary modification and associated 10 CFR 50.59 screening against system requirements to determine whether there were any effects on system operability or availability and if consistency with plant documentation and procedures was maintained. The inspectors walked down the modification to ensure that it was installed in accordance with the modification documents and reviewed post-installation and removal testing to verify that the actual impact on permanent systems was adequately verified by the tests. Additionally, the inspectors reviewed the procedures that were revised to support this temporary modification.

This constitutes one sample.

b. <u>Findings</u>

No findings of significance were identified.

1EP2 Alert and Notification System (ANS) Testing (71114.02)

a. Inspection Scope

The inspectors reviewed and discussed with licensee emergency preparedness staff records of the operation, maintenance, and testing of the ANS in the Davis-Besse Emergency Planning Zone (EPZ) to determine whether the ANS equipment was adequately maintained and tested during 2004 and 2005 in accordance with emergency plan commitments and procedures. The inspectors reviewed and discussed correspondence between State, County, and Federal Emergency Management Agency (FEMA) staffs regarding FEMA-approved changes implemented in 2005 to the ANS testing program conducted by Ottawa County staff and to the siren activation equipment that would be used by those staffs. The inspectors also reviewed and discussed the status of the EPZ siren upgrade project, which was completed in January 2006 except for the proposed relocations of two of the 54 EPZ sirens, to verify that these equipment upgrades and proposed siren relocations were being adequately coordinated with State, County, and FEMA officials. The inspectors also reviewed a sample of non-scheduled maintenance records to determine whether ANS equipment malfunctions were given timely attention and whether the corrective action program was adequately used to track these malfunctions. The inspectors reviewed records of scheduled ANS tests conducted from April 2005 through December 2005.

This constitutes one sample.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors reviewed and discussed procedures containing details on the primary and alternate methods of initiating an ERO activation to augment the on-shift ERO. The inspectors also reviewed the procedure and discussed the processes for maintaining the Station's ERO roster and the ERO telephone directory. The inspectors reviewed records of semi-annual, unannounced, off-hours augmentation drills, which were conducted in 2004 and 2005 and involved ERO members assigned to every emergency response facility, to assess the adequacy of the drills' critiques and a sample of resulting corrective actions. The inspectors also reviewed records of an additional unannounced, off-hours augmentation drill conducted in April 2004, which involved ERO members actually reporting to their assigned response facilities, to understand how this drill's critique resulted in increased consistency between response facilities' implementing procedures and the Emergency Plan's corresponding minimum staffing commitments. The inspectors reviewed and discussed other outcomes of the April 2004 augmentation drill, which were an internal memorandum from licensee senior management and a subsequent Davis-Besse Business Practice (DBBP), which summarized the licensee's expectations for its ERO members, to assess the adequacy of these expectations and their consistency with emergency plan commitments. The inspectors also reviewed the ERO roster to verify that good numbers of personnel were assigned to each key and support position. The inspectors reviewed training records of a random sample of 36 ERO members, who were assigned to key and support positions, to verify that they were currently trained for their assigned positions.

This constitutes one sample.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level (EAL) and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors reviewed Revision 5 to implementing procedure RA-EP-01500, Emergency Classification, and the associated 10 CFR 50.54(q) review records to determine whether the licensee adequately implemented EAL and terminology changes associated with NRC Bulletin 2005-02. The inspectors also reviewed 10 letters, dated December 2005, from licensee management to relevant State, Ottawa County, and Lucas County officials to verify that these letters and their enclosures adequately met the annual EAL review requirement of 10 CFR Part 50, Appendix E, Paragraph IV.B.

This constitutes one sample.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed portions of Quality Assurance staff's 2004 and 2005 quarterly audits that addressed aspects of the licensee's EP program to verify that these independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also assessed the adequacy of letters sent in 2004 and 2005 to State and County officials that transmitted the results of Quality Assurance staff's assessments of the adequacy of the licensee's interfaces with State and County emergency management agencies and local support organizations. The inspectors also reviewed records of a sample of EP drills conducted during 2004 and 2005, as well as the May 2005 biennial exercise, to verify that the licensee adequately critiqued these drills and the exercise and to determine if corrective actions on identified concerns were either adequately completed or in progress.

This constitutes one sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors discussed performance indicators with the radiation protection staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators in the occupational exposure cornerstone that had not been identified and reviewed. This review constitutes one sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors identified three radiologically significant work areas within radiation areas, high radiation areas (HRA) and airborne areas in the auxiliary and containment buildings. Selected work packages and radiation work permits (RWP) were reviewed to determine if radiological controls including surveys, postings, air sampling data and barricades were acceptable. Work areas included:

- RWP 2006-5104; Reactor Head Disassembly/Reassembly Work Activities; Revision 0
- RWP 2006-6006; Radiography In The Decay Heat Cooler Room; Revision 0
- RWP 2006-5401; RCP 2-1 & 2-2 Inspection And Replacement Activities; Revision 0
- RWP 2006-5300; Steam Generator Work Activities; Revision 0

This review represented one sample.

The identified radiologically significant work areas were walked down and surveyed to determine if the prescribed RWP, procedures, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located. This review constitutes one sample.

The inspectors reviewed selected RWPs, and associated radiological controls used to access these and other radiologically significant areas, and evaluated the work control instructions and control barriers that were specified in order to determine if the controls and requirements provided adequate worker protection. Site TS requirements for HRAs and locked high radiation areas were used as standards for the necessary barriers. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. The inspectors attended pre-job briefings to determine if instructions to workers emphasized the actions required when their electronic dosimeters noticeably malfunctioned or alarmed. This review constitutes one sample.

The inspectors reviewed job planning records and interviewed licensee representatives to determine if there were airborne radioactivity areas in the plant with a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. Barrier integrity and engineering controls performance, such as high efficiency particulate filtration ventilation system operation and use of respiratory protection, were evaluated for worker protection. Work areas having a history of, or the potential for, airborne transuranic isotopes were reviewed to determine if the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection. This review constitutes one sample.

The adequacy of the licensee’s internal dose assessment process for internal exposures greater than 50 millirem committed effective dose equivalent was assessed to determine if affected personnel were properly monitored utilizing calibrated equipment and that the data was analyzed and internal exposures were properly assessed in accordance with licensee procedures. This review constitutes one sample.

The inspectors reviewed the licensee’s physical and programmatic controls for highly activated and/or contaminated materials (non-fuel) stored within the spent fuel pool.

This review constitutes one sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee’s self-assessments, audits, and condition reports related to the access control program to determined if identified problems were entered into the corrective action program for resolution. This review constitutes one sample.

Corrective action reports related to access controls and high radiation area radiological incidents (non-performance indicator occurrences identified by the licensee in HRAs <1Rem/hr) were reviewed. Staff members were interviewed and corrective action documents were reviewed to determine if follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of Non-Cited Violations tracked in the corrective action system; and
- Implementation/consideration of risk significant operational experience feedback.

This review constitutes one sample.

The inspectors evaluated the licensee's process for problem identification, characterization, prioritization, and determined if problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies identified in the problem identification and resolution process, the inspectors determined if the licensee's self-assessment activities also identified and addressed these deficiencies.

This review constitutes one sample.

The inspectors discussed performance indicators with the radiation protection staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators for the occupational exposure cornerstone that had not been reviewed. There were none to evaluate.

This review constitutes one sample.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors evaluated selected jobs being performed in radiation areas, potential airborne radioactivity areas, and HRAs for observation of work activities that presented the greatest radiological risk to workers and included areas where radiological gradients were present (Section 2OS1.2). This involved work that was estimated to result in higher collective doses, and included radiography preparations, vessel head inspection, steam generator inspection, and other selected work areas in the containment building.

The inspectors reviewed radiological job requirements including RWP and work procedure requirements, and attended as-low-as-is-reasonably-achievable (ALARA) job briefings. Job performance was observed with respect to these requirements to determine if radiological conditions in the work areas were adequately communicated to workers through pre-job briefings and radiological condition postings.

This review constitutes one sample.

The inspectors also evaluated the adequacy of radiological controls including required radiation, contamination and airborne surveys for system breaches and entry into HRAs. Radiation protection job coverage, including direct visual surveillance by radiation protection technicians along with the remote monitoring and teledosimetry systems and contamination control processes, was evaluated to determine if workers were adequately protected from radiological exposure.

This review constitutes one sample.

Work in high radiation areas having significant dose rate gradients was observed to evaluate the application of dosimetry to effectively monitor exposure to personnel, and to determine if licensee controls were adequate. The inspectors observed radiation protection coverage of the vessel head inspection and steam generator work which involved controlling worker locations based on radiation survey data and real time monitoring using teledosimetry in order to maintain personnel radiological exposure ALARA.

This review constitutes one sample.

b. <u>Findings</u>

No findings of significance were identified.

.5 <u>High Risk Significant, High Dose Rate High Radiation Area, and Very High Radiation Area Controls</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the licensee's performance indicators for high risk, high dose rate HRAs, and for very high radiation areas to determine if workers were adequately protected from radiological overexposure. Discussions were held with radiation protection management concerning high dose rate HRA and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection. This was done to determine if any procedure modifications had substantially reduced the effectiveness and level of worker protection.

This review constitutes one sample.

The inspectors evaluated the controls including procedures DB-HP-01152, "Performance Of High Exposure Work", Revision 6; DB-HP 01102, "Industrial Radiography/Densitometry", Revision 3; DB-HP 01109, "High Radiation Area Access Control", Revision 21, that were in place for special areas that had the potential to become very high radiation areas during certain plant operations. Discussions were held with radiation protection (RP) supervisors to determine how the required communications between the RP group and other involved groups would occur beforehand in order to allow corresponding timely actions to properly post and control the radiation hazards.

This review constitutes one sample.

During plant walkdowns, the posting and locking of entrances to high dose rate HRAs, and very high radiation areas were reviewed for adequacy.

This review constitutes one sample.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements. The inspectors also evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present.

This review constitutes one sample.

Radiological problem reports, which found that the cause of an event resulted from radiation worker errors, were reviewed to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

This review constitutes one sample.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

The inspectors observed and evaluated RP technician performance with respect to RP work requirements. This was done to evaluate whether the technicians were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

This review constitutes one sample.

Radiological problem reports, which found that the cause of an event was RP technician error, were reviewed to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

This review constitutes one sample.

b. Findings

No findings of significance were identified.

2OS2 As Low As Is Reasonably Achievable (ALARA) Planning And Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends along with ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current 3-year rolling average collective exposure and comparing the site's radiological exposure on a yearly basis for the previous 5 years.

This review constitutes one sample.

The inspectors reviewed the outage work scheduled during the inspection period along with associated work activity exposure estimates including the five work activities which were likely to result in the highest personnel collective exposures.

This review constitutes one sample.

Site specific trends in collective exposures and source-term measurements were reviewed.

This review constitutes one sample.

Procedures associated with maintaining occupational exposures ALARA, and processes used to estimate and track work activity specific exposures were reviewed.

This review constitutes one sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning.

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities, ranked by estimated exposure, that were in progress and selected the five work activities of highest exposure significance.

This review constitutes one sample.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to determine if the licensee had established procedures, along with engineering and work controls, that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, or special circumstances.

This review constitutes one sample.

The interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups were evaluated to identify interface problems or missing program elements. This review constitutes one sample.

The integration of ALARA requirements into work procedures and RWP documents was evaluated to determine if the licensee's radiological job planning would reduce dose.

This review constitutes one sample.

Shielding requests from the radiation protection group were evaluated with respect to dose rate reduction and reduced worker exposure, along with engineering shielding responses follow up.

This review constitutes one sample.

The inspectors reviewed work activity planning to determine if there was consideration of the benefits of dose rate reduction activities such as shielding provided by water filled components and piping, job scheduling, along with shielding and scaffolding installation and removal activities.

This review constitutes one sample.

b. Findings

No findings of significance were identified.

.3 Job Site Inspections and ALARA Controls

a. Inspection Scope

The inspectors selected five work activities in radiation areas, potential airborne radioactivity areas, and HRAs for observation, emphasizing work activities that presented the greatest radiological risk to workers. Jobs that were expected to result in significant collective doses and involved potentially changing or deteriorating radiological conditions were observed. These included vessel head, radiography and steam generator inspection activities, and reactor coolant pump work. The licensee's use of ALARA controls for these work activities was evaluated using the following:

- The use of engineering controls to achieve dose reductions was evaluated to determine if procedures and controls were consistent with the ALARA reviews; that sufficient shielding of radiation sources was provided for, and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

  This review constitutes one sample.

- Job sites were observed to determine if workers were utilizing the low dose waiting areas and were effective in maintaining their doses ALARA by moving to the low dose waiting area when subjected to temporary work delays.

  This review constitutes one sample.

- The inspectors attended ALARA pre-job briefings and observed ongoing work activities to determine if workers received appropriate on-the-job supervision to ensure the ALARA requirements were met. This included determining if the first-line job supervisor ensured that the work activity was conducted in a dose efficient manner by minimizing work crew size, ensuring that workers were properly trained, and that proper tools and equipment were available when the job started.

  This review constitutes one sample.

b. Findings

No findings of significance were identified.

.4 Source-Term Reduction and Control

a. Inspection Scope

The inspectors reviewed licensee records to determine the historical trends and current status of tracked plant source terms and determined if the licensee was making allowances and had developed contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry.

This review constitutes one sample.

The inspectors determine if the licensee had developed an understanding of the plant source-term, which included knowledge of input mechanisms in order to reduce the source term. The licensee's source-term control strategy, which included a process for evaluating radionuclide distribution plus a shutdown and operating chemistry plan which can minimize the source-term external to the core, was evaluated. Other methods used by the licensee to control the source term, including component/system decontamination, hotspot flushing and the use of shielding, were evaluated.

These reviews constitute one sample.

The licensee's process for identification of specific sources was reviewed along with exposure reduction actions and the priorities the licensee had established for implementation of those actions. Results achieved against these priorities since the last refueling cycle were reviewed. For the current assessment period, source-term reduction evaluations were verified, and actions taken to reduce the overall source-term were compared to the previous year.

These reviews constitute one sample.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance

a. Inspection Scope

Radiation worker and RP technician performance was observed during work activities being performed in radiation areas, airborne radioactivity areas, and HRAs that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas and that work activity controls were being complied with. Also, radiation worker training and skill levels were reviewed to determine if they were sufficient relative to the radiological hazards and the work involved.

This review constitutes one sample.

b. Findings

No findings of significance were identified.

.6 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee’s self-assessments, audits, and Special Reports related to the ALARA program since the last inspection to determine if the licensee’s overall audit program’s scope and frequency for all applicable areas under the Occupational Cornerstone met the requirements of 10 CFR 20.1101c.

This review constitutes one sample.

The inspectors determined if identified problems were entered into the corrective action program for resolution, and that they had been properly characterized, prioritized, and resolved. This included dose significant post-job (work activity) reviews and post-outage ALARA report critiques of exposure performance.

This review constitutes one sample.

Corrective action reports related to the ALARA program were reviewed and staff members were interviewed to determine if follow-up activities had been conducted in an effective and timely manner commensurate with their importance to safety and risk using the following criteria:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of NCVs tracked in the corrective action system; and
- Implementation/consideration of risk significant operational experience feedback.

This review constitutes one sample.

The inspectors also determined if the licensee’s self-assessment program identified and addressed repetitive deficiencies and significant individual deficiencies that were identified in the licensee's problem identification and resolution process.

This review constitutes one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

Cornerstone: Emergency Preparedness

.1 Emergency Preparedness Strategic Area

a. Inspection Scope

The inspectors reviewed the licensee's records associated with the three EP performance indicators (PIs) listed below. The inspectors verified that the licensee accurately reported these indicators in accordance with relevant procedures and Nuclear Energy Institute guidance endorsed by NRC with one minor exception that the licensee planned to correct in its next quarterly PI data submittal. Specifically, the inspectors reviewed licensee records associated with PI data reported to NRC for the period April 2005 through December 2005. Reviewed records included: procedural guidance on assessing opportunities for the three PIs; assessments of PI opportunities during pre-designated Control Room Simulator training sessions, the 2005 biennial exercise, and several integrated emergency response facility drills; revisions of the roster of personnel assigned to key ERO positions; and results of ANS operability tests, which increased in frequency at the beginning of October 2005. The following PIs were reviewed:

- Alert and Notification System Reliability;
- Emergency Response Organization Drill Participation; and
- Drill and Exercise Performance.

This constitutes three samples.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Daily Review

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment deficiencies or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This screening was accomplished by reviewing documents entered into the licensee CAP and review of document packages prepared for the licensee's daily condition report review.

b. Findings

No findings of significance were identified.

.2 Annual Sample: Review of Issues with Emergency Diesel Generator 2 (EDG2)

a. Inspection Scope

The inspectors reviewed licensee actions to determine the cause of and define corrective actions for failure of an exhaust valve bridge on emergency diesel generator 2 which rendered the emergency diesel inoperable. The inspectors reviewed the root cause report for CR 06-00154, “No. 2 EDG Broken Parts in Rocker Arm Area,” and CR 06-00159, “Tapping Noise on EDG2 During Testing Following Maintenance.” The reviewed focused on the licensee’s review of past operability, cause identification, and proposed actions to reduce the chance of a future similar issue. The inspectors additionally reviewed other condition reports on the emergency diesel generators for indication of any generic issues with the equipment.

b. Findings and Observations

Introduction:

The inspectors determined that an unresolved item (URI) existed concerning the emergency diesel generator 2 (EDG2) being inoperable because of damage to the exhaust bridge of cylinder number 4. This condition was not recognized during post maintenance testing of EDG2 on January 13, 2006, and was not recognized until preparations for a surveillance activity on January 20, 2006.

Description:

During the period of January 8, 2006, through January 14, 2006, EDG2 was removed from service for preventive maintenance scheduled on a 6 year interval. Activities accomplished included replacement of cylinder valve bridges which included rocker arms. Procedure DB-MN-09320, “Emergency and Station Blackout Diesel Engine Maintenance,” Enclosure 4, contains steps for setting the rocker arm to exhaust valve settings (the “lash adjustments”). That enclosure had eight steps for lash adjustment setting. The eighth step was to torque the locknut of the adjusting screw in each rocker arm to 80 ft-lbs. After the eight steps were completed for each of the 20 cylinders of EDG2, a step nine of that enclosure required initials to document that all eight steps were worked. Step nine did not require any concurrent or independent verification.

After completion of the maintenance activities, EDG2 was started in the evening of January 13, 2006, and loaded for, among other requirements, post-maintenance testing. During the loaded run of EDG2 a tapping noise was heard which was believed to be originating in the area of cylinder 4. CR 06-00159 indicates that a visual inspection of the area with the rocker arms during the EDG2 shutdown did not find any obvious source of the noise. The root cause analysis report stated that discussions between the vendor and personnel present, as well as examination of test data, indicated that the tapping noise was due to a lash adjustment being set wrong and the diesel cylinders were operating normally. A work order notification was written to have the noise investigated and then EDG2 was declared operable at 0200 hours on January 14, 2006.

EDG2 was next scheduled to be operated on January 20, 2006. During preparatory activities, the area containing the rocker arms was again visually examined. This visual examination of conditions self-revealed that there was damage to the left valve bridge of cylinder 4 and that the left rocker arm lash adjustment screw lock nut was missing from the top of the rocker arm. The licensee formed a problem solving team to determine necessary repairs. The inspectors reviewed the those activities and the restoration of EDG2 (Section 1R13).

Licensee review and documentation of that review stated that there was no direct evidence of why the lock nut was missing which subsequently permitted the lash adjustment to change which subsequently caused damage to the overall assembly. The licensee concluded that the most likely cause was that the lock nut had not been properly torqued. The licensee did not rule out a mechanical failure and did plan on having damaged components reviewed for failure mechanisms.

Assuming that the lock nuts were not torqued as required by procedure, the licensee identified contributing causes included that the normal expectation was that a lead mechanic signs the governing procedure that the work was properly completed although the work can be done by personnel working under the direction of the lead mechanic. The licensee also identified that the physical arrangement of the diesel allowed work on lash adjustments to occur concurrently on both sides of EDG2 while only permitting close observation of one side at a time. Additionally the licensee concluded that the arrangement of the governing procedure, DB-MM-09320, did not facilitate easy use. There existed multiple enclosures with no particular rationale for the sequencing of the enclosures.

Licensee’s proposed actions to preclude recurrence of a similar event included modifying the governing procedure to better govern actual scheduled work. This would include incorporating a specific signoff for the lock nut torquing and a redesign of the procedure to include a separate enclosure for each of the 20 cylinders. The licensee proposed that the individual performing the work would initial that the task was completed. The inspectors determined that the proposed actions, once completed, were reasonable but noted that the proposed actions could make the governing procedures larger and potentially more cumbersome.

Licensee review of the extent of condition and inspectors review of condition reports did not identify a concern that a similar significant issue exists with the site’s other emergency diesel generators. The licensee did identify several site and industry events on improper torquing including a bolt torquing issue in 2002 and another in 2003 on other components associated with emergency diesel generators. The licensee determined that the specific events and their dates of occurrence did not warrant additional actions beyond those specifically proposed as corrective for this event.

The inspectors did not complete a review of the licensee’s past operability analysis and the significance of licensee identified inoperabilty by the end of the inspection.

Therefore, this issue is considered an unresolved item (URI 05000346/200600203) pending completion of those reviews.

4OA3 Event Followup (71153)

.1 (Closed) LER 05000346/2003-007-00: AC System Shows Potential Loss of Offsite Power Following Design Basis Accident

On June 6, 2003, while upgrading the analysis of the electrical distribution system, the licensee identified that upon a postulated loss of coolant accident (LOCA) with degraded voltage conditions, a potential existed for a voltage transient causing insufficient voltage to operate essential 480 VAC equipment. Furthermore, if a startup transformer and/or bus tie transformer were out of service for this condition, the undervoltage relays may actuate causing a loss of preferred power to the 4160 V essential buses, resulting in the loading of the EDGs. The plant was in Mode 5 at the time of discovery.

In the investigation associated with the event described in this LER, the licensee concluded that the contributing causes of the event were incomplete AC system analysis and unverified assumptions while using an electrical system analysis program. The licensee initiated a number of corrective actions including a change in the transformer tap settings to increase the 480 VAC bus voltage, a change in the transformer tap settings to increase the 240 VAC bus voltage, installing interposing relays in the starter control circuits for Main Feedwater Isolation Valves FW601 and FW612, a change in the trip setpoints and allowable value for the 90 percent undervoltage essential bus feeder trip relays and submitting a TS amendment for the 90 percent undervoltage relays. The inspectors reviewed the licensee's corrective actions for CR 03-04435 and found the actions adequate and completed.

The inspectors determined that there was one licensee-identified finding. The failure to have complete analysis and to verify assumptions for the electrical distribution system was a violation of Criterion III, "Design Control," of Appendix B to 10 CFR Part 50. The finding was considered more than minor because it involved the design control attributes of maintaining the functionality of the electrical distribution system and affects the mitigating system objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding was screened as having very low significance. The enforcement aspects of the violations are discussed in Section 4OA7. This LER is closed.

.2 (Closed) Licensee Event Report (LER) 05000346/2005-006-00: SW38 (Service Water) Found Out of Position

On November 15, 2005, service water valve 38 (SW38) was found out its required position of being open. With this valve closed,component cooling water (CCW) train 2 was inoperable and unable to fulfill its safety function. This placed the plant in TS action statements and an unreviewed orange risk category. In addition to CCW train 2 inoperability, the following systems were declared inoperable: decay heat train 2, high pressure train 2, emergency diesel generator 2, containment hydrogen analyzer train 2 and radiation element 4598BA. The LER was reviewed by the inspectors with no additional findings of significance being identified and no additional violation of NRC requirements. The licensee documented this event in CR 50-05650 and CR 05-05666. The event was also documented as a licensee-identified NCV in IR2005009. This LER is closed.

.3 Event at Licensee's Vehicle Inspection Facility

a. Inspection Scope

On January 23, 2006, the inspectors responded to an event with a vehicle at the licensee's vehicle inspection facility. The inspectors reviewed the actions taken by licensee personnel to respond to the event and the appropriateness of the actions. Additionally, the inspectors reviewed licensee procedures for conformance with NRC requirements.

b. Findings

No findings of significance were identified.

4OA5 Other

.1 Implementation of Temporary Instruction (TI) 2515/165 - Operational Readiness of Offsite Power and Impact on Plant Risk

a. Inspection Scope

The objective of TI 2515/165, "Operational Readiness of Offsite Power and Impact on Plant Risk," was to confirm, through inspections and interviews, the operational readiness of offsite power systems in accordance with NRC requirements. From March 7 through March 24, 2006, the inspectors reviewed licensee procedures and discussed the attributes identified in TI 2515/165 with licensee personnel. In accordance with the requirements of TI 2515/165, the inspectors evaluated the licensee's operating procedures used to assure the functionality/operability of the offsite power system, as well as the risk assessment, emergent work, and/or grid reliability procedures used to assess the operability and readiness of the offsite power system.

The information gathered while completing this Temporary Instruction was forwarded to the Office of Nuclear Reactor Regulation for further review and evaluation.

b. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

a. Inspection Scope

On February 11, 2003, the NRC issued Order EA-03-009 (ADAMS Accession Number ML030410402). This order required examination of the reactor pressure vessel head and associated vessel head penetration (VHP) nozzles to detect PWSCC of VHP nozzles, and corrosion of the vessel head. The purpose of TI 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles," was to implement an NRC review of the licensee's head and VHP nozzle inspection activities required by NRC Order EA-03-009.

The inspectors performed a review of the licensee's procedures, equipment, and personnel used for examinations of the reactor vessel closure head (RVCH) and VHP nozzles to confirm that the licensee met requirements of NRC Order EA-03-009 (as revised by NRC letter dated February 20, 2004). The results of the inspectors' review included documentation of observations in response to the questions identified in TI 2515/150.

From March 14, 2006 through March 16, 2006, the inspectors performed a review of the licensee's RVCH inspection activities completed in response to NRC Order EA-03-009. This review included:

- observation of the licensee personnel conducting remote visual examination of VHP nozzle locations from the on-site data acquisition trailer;
- direct visual observation from two access doors on the service structure of the bare metal surface of the RVCH including portions of 12 VHP nozzle locations;
- interviews with nondestructive examination personnel performing non-destructive examinations of the VHP nozzles;
- certification records of nondestructive examination personnel performing examinations of the RVCH and VHP nozzles;
- visual examination procedures used for examinations of the RVCH and VHP nozzles;
- procedures used for identification and resolution of boric acid leakage from systems and components above the vessel head; and
- Visual examination records for the RVCH and VHP nozzles.

The inspectors conducted these reviews to confirm that the licensee performed the vessel head examinations in accordance with requirements of NRC Order EA-03-009, using procedures, equipment, and personnel qualified for the detection of PWSCC in vessel VHP nozzles and detection of vessel head wastage.

From March 14, 2006, through March 16, 2006, the inspectors reviewed the licensee's VHP nozzle susceptibility ranking calculation to:

- verify that appropriate plant-specific information was used as input;
- confirm the basis for the head temperature used by licensee; and
- determine if previous VHP cracks had been identified, and if so, documented in the susceptibility ranking calculation.

The documents reviewed by the inspectors in conducting this inspection are listed in the attachment to this report.

b. Observations

Summary: As of the end of operating cycle 13, the Davis-Besse vessel head was at 2.38 effective degradation years (EDY), which is in the low susceptibility ranking category as described in NRC Order EA-03-009. To meet the inspection requirements of Order EA-03-009, the licensee completed a visual examinations for each of the 69 VHP nozzles which included the head vent line. The licensee did not identify any evidence of leakage or head corrosion and none of the 69 VHP nozzles was considered masked.

Overall, the inspectors concluded that the licensee had completed an examination of the reactor vessel head which was consistent with the requirements of NRCs Order EA-03-009. The inspectors documented conclusions in response to specific questions related to the quality of personnel, procedures, and equipment used to perform the vessel head examination. Specifically, the inspectors evaluated and answered the following questions:

21. For each of the examination methods used during the outage, was the examination:

a. Performed by qualified and knowledgeable personnel?

Yes. The inspectors verified that the examinations were performed by a licensee contractor, certified as an ASME Code Level II VT-2 examiner. Additionally, the licensee's contract examiner received training on industry vessel head penetration leakage experiences documented in EPRI / MRP 1006296, "Visual Exam for Leakage of PWR Reactor Head Penetrations on Top of RPV [Reactor Pressure Vessel] Head."

b. Performed in accordance with demonstrated procedures?

Yes. The inspectors verified that the bare metal visual examination was conducted in accordance with procedures, which required qualified examination personnel with knowledge of identifying VHP nozzle leakage along with resolution and lighting, in accordance with the ASME Code VT-2 requirements. The inspectors concluded that the AREVA procedures 54-ISI-367-07, "Visual Examination for Leakage of Reactor Head Penetrations", and procedure 6027636A, "Reactor Head Nozzle Penetration Remote Visual Inspection Plan," used to conduct this examination contained adequate guidance for the licensee's contractor inspection staff.

c. Able to identify, disposition, and resolve deficiencies?

Yes. Based on observation of approximately 30 percent of the licensee's remote visual examination process, the inspectors concluded that sufficient access existed to complete the intended coverage of the bare metal of the reactor head, as well as 360 degree coverage at each VHP nozzle. The licensee perform a calculation which demonstrated that the inspection coverage achieved was in excess of 96 percent of the bare metal surface of the head which exceeded the 95 percent minimum coverage required by NRC Order EA-03-009. The licensee staff confirmed visual acuity and lighting at least once per shift, and the NRC inspectors considered the visual examination resolution to be adequate to resolve indications of boric acid leakage, (boron deposits) if any had been present.

d. Capable of identifying the PWSCC and/or reactor vessel head corrosion phenomena described in Order EA-03-009?

Yes. The inspectors determined through direct observation of the remote visual examination process that the licensee's efforts were capable of detecting and characterizing vessel head nozzle penetration leakage, PWSCC and/or reactor vessel head corrosion if any had been present.

2. What was the condition of the reactor head (e.g., debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

The reactor vessel head insulation package was located several inches above the center of the head which allowed access for the low profile crawler mounted camera through an opening in the service structure. The licensee was able to position the camera such that all four quadrants for each of the 69 head penetrations were examined without obstruction. During the examination, the NRC inspectors noted that dust/debris, and some light surface rust were present on the head and/or penetration surfaces which did not interfere with the examination. The licensee identified 17 VHP nozzles with rust/corrosion products located within the annulus region, which were not of sufficient volume to mask the ability to identify leaking VHP nozzles. The licensee documented several nozzle locations with debris, that were blown away with a low pressure air source and reinspected to confirm no leakage.

During the mid-cycle outage in 2003, the licensee had identified nozzle locations with black deposits, (reference NRC report 05000346/2005003 and licensee CR 05-00666) which the licensee attributed to corrosion of iron oxide deposits. The inspectors compared a sample of photographs for these nozzle locations with that observed during the current outage and did not identify any significant changes.

3. Could small boron deposits, as described in Bulletin 2001-01, be identified and characterized?

Yes. The inspectors determined through direct observation of the inspection process, a review of the visual inspection procedure, and a review of the qualifications and training of the VT-2 examiners, that small boron deposits, as described in the Bulletin 2001-01, could be identified and characterized.

4. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

Not applicable. The licensee did not identify any material deficiencies associated with the head visual examination that required repair.

5. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

   None. The licensee had sufficient access to perform a remote visual examination with 360 degree coverage of each penetration.

6. What was the basis for the temperatures used in the susceptibility ranking calculation, were they plant-specific measurements, generic calculations (e.g., thermal hydraulic modeling, instrument uncertainties), etc.?

   On March 13, 2006, the inspectors reviewed C-ME-099.99-013 "Effective Degradation Years Calculation for Alloy 600/82/182 PWSCC Susceptibility Determination Related Application" Revision 0. The licensee performed this calculation with estimated data inputs for power level and cycle length in July of 2005, and the operating cycle No. 13 ended on March 6, 2006. The inspectors questioned the licensee staff as to how this calculation performed with data estimates so far in advance of the end of the operating cycle met the NRC order. Specifically, NRC Order EA 03-009 Section IV.A required "This calculation shall be performed with best estimate values for each parameter at the end of each operating cycle for the RPV head that will be inservice during the subsequent operating cycle." Contrary to this requirement, the licensee used estimated data for power level, and cycle length approximately 8 months prior to the end of operating cycle No. 13. The licensee entered this issue into the corrective action system (CR 06-00935), and reperformed this calculation on March 15, 2006. Because the revised calculation changed by only 0.01 EDY and did not affect the head examination requirements, the inspectors concluded that this issue was a violation of NRC Order EA-03-009 of minor significance.

   The inspectors reviewed C-ME-099.99-013 "Effective Degradation Years Calculation for Alloy 600/82/182 PWSCC Susceptibility Determination Related Application" Revision 1, and identified that plant specific inputs (hot leg temperatures) had been used for estimated head temperature during the operating cycle. The licensee did not consider instrument uncertainty in this calculation, but the licensee's basis for selection of hot leg temperature had been previously described in a letter sent by the licensee to the NRC.

7. During non-visual examinations, was the disposition of indications consistent with the guidance provided in Appendix D of this TI? If not, was a more restrictive flaw evaluation guidance used?

   Not applicable. Non-visual examinations were not performed.

8. Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the vessel head?

   Yes. The NRC inspectors verified that visual examinations to detect potential boric acid leaks from pressure-retaining components above the vessel head were conducted in accordance with AREVA procedure 6029296A, "Reactor Head

Nozzle Flange to CRDM Motor Tube Flange and Split Ring Remote Visual Inspection Plan for Davis Besse Unit 1."

9. Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the vessel head?

   Yes. The licensee observed a small accumulation of boric acid deposits at control rod drive mechanism housing vent valve packing (RC-175A) at the beginning of RFO - 14 and concluded that this leakage did not contact the vessel head (CR 06-00807). The licensee staff attributed the light surface corrosion and rust streaks identified at discrete locations on the vessel head to component cooling water leakage which occurred at the control rod drive mechanism cooling connections during the current and prior refueling outages (CR 03-08659).

c. Findings

No findings of significance were identified.

.3 Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the final report for the INPO plant assessment of Davis-Besse plant conducted in August 2005. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to verify if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings of significance were identified.

.4 Company Nuclear Review Board Meeting

The inspectors attended a portion of the Davis-Besse Company Nuclear Review Board meeting that was held on February 10, 2006. The inspectors attended presentations given by subcommittees involved with reviewing the corrective action program, the management oversight activity observation program, and outage preparations. Discussions included the state of safety conscious work environment, challenges to outage schedule, and the need to be more self-critical in evaluation of performance. The inspectors determined that, for the presentations observed, the depth of evaluation and the material selected for review by each subcommittee appeared appropriate and that the Board was sufficiently challenging in their evaluation of the licensee.

.5 Site Visit By Senior NRC Management

On March 20 and 21, 2006, NRC senior management from Region III and the Office of Nuclear Reactor Regulation, among others from the NRC, visited the site. A tour of the containment was conducted and the licensee gave a presentation on the design of the containment emergency recirculation sump (ML060860351).

.6 Evaluation of the Independent Engineering Assessment Report

a. Inspection Scope

As part of the NRC inspection activities performed to verify the licensee's compliance with the requirements for independent assessments, the inspectors reviewed the March 8, 2004 Confirmatory Order required Calendar Year 2005 Independent Assessment of the Engineering Programs' Effectiveness at the Davis-Besse Nuclear Power Station, dated February 6, 2006. As part of the Order related inspection activities, the inspectors reviewed the report to ensure that it provided an overall assessment of Engineering performance, that the assessment team's activities supported the report's conclusions, and that the licensee documented specific action plans to address deficiencies that were documented in the report.

b. Observations and Findings

The second annual Davis-Besse Independent Engineering Assessment required by the Order was performed during the time period of November 28, 2005, to December 9, 2005. The inspectors reviewed and documented their evaluation of both the Independent Assessment Plan and the on site implementation in IR 05000346/2005009. On February 6, 2005, the licensee submitted the Independent Assessment of the Engineering Programs Effectiveness at the Davis-Besse Nuclear Power Station final report to the NRC. This report documented the findings of that assessment.

The final report was broken down into six areas of assessment:

- Plant Modification Process;
- Calculation Process;
- System Engineering;
- Corrective Action Program;
- Actions taken in response to areas of improvement identified during the 2004 Independent Assessment of Engineering; and
- Self assessment.

The Team reviewed engineering products in a number of areas and did not identify any discrepancies that were considered significant in terms of the validity of the work product, or indicative of a systematic deficiency in engineering work performance or management. The Team identified one "area of strength" and six "areas in need of attention". An area in need of attention was defined as an identified performance, program, or process element within an area of assessment that, although sufficient to meet its basic intent, management attention is required to achieve full effectiveness and consistency. These "areas in need of attention" are not required to be addressed by formal Action Plans submitted to the NRC, but were considered for entry into the Corrective Action Program.

Overall the effectiveness of engineering programs was rated as effective. The following observations were noted:

- Quality of Engineering work products and Engineering support work has improved.

- Favorable influences have included stable, effective leadership, deployment of fleet standards and methods, fleet support, extensive self checking and performance monitoring, and backlog reduction.
- Focus has been on standards, processes, backlog reduction, and post restart commitments. The challenge will be to transition focus and techniques to maintaining and improving performance of organization and plant.

The "area of strength" identified by the Team related to improved Engineering performance and environment. This conclusion was based on the following observations:

- Engineering programs are robust.
- The Calculation Program has improved.
- Operability Evaluations are few in number and of high quality.
- Davis Besse Condition Reports are screened for applicability to Perry and Beaver Valley.
- An effective management team is in place.

The Team assessed the licensee's progress on the three "areas for improvement" (AFIs) identified during the 2004 Independent Assessment. The Team had identified that the initiation and closeout of documentation associated with modifications were untimely and inefficient. Currently, adequate progress on this issue was observed by the Team. The number of Engineering Change Requests (ECR) requiring disposition was reduced from approximately 550 to about 45, and all but one of the completed ECRs identified in the 2004 assessment (approximately 56) have been closed out. The backlog of open modifications and requests for modification has declined from about 1200 in October 2004 to about 800 at the time of this assessment.

The Team had identified that the Calculation Improvement Program was not receiving sufficient management focus to ensure timely completion. Currently, the Team identified that all issues associated with this AFI have been satisfactorily resolved, and this finding is considered closed.

The Team had identified that the Self Assessment Process was not being fully utilized to improve engineering performance. Currently, adequate progress on this issue was observed by the team. At the time of this assessment, 7 of 11 scheduled self assessments were completed. One self assessment was cancelled and replaced with an ongoing program, one was postponed until some prerequisites were met, and the other two were scheduled for completion by the end of the year. The completed self assessments reviewed by the Team were judged to be of high quality.

c. <u>Conclusions</u>

The inspectors determined that the Team's inspection activities were in accordance with the Inspection Plan and were of sufficient depth and scope to develop an adequate assessment of engineering performance.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. M. Bezilla, and other members of licensee management on April 12, 2006. The licensee acknowledged the findings presented. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Emergency Preparedness inspection with Mr. R. Farrell on February 17, 2006.
- Access control to radiologically significant areas, and the ALARA planning and controls program with Mr. M. Bezilla on March 17, 2006.
- Temporary Instruction 2515/150, and Procedure 71111.08 with Mr. B. Allen and other members of licensee management at the conclusion of the inspection on March 23, 2006. The inspectors returned proprietary information reviewed during the inspection and the licensee confirmed that none of the potential report input discussed was considered proprietary.

4OA7 Licensee-Identified Violations

The following violations of NRC requirements of very low safety significance (Green) was identified by the licensee which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositions as an NCV.

- Criterion III, “Design Control,” of 10 CFR Part 50 Appendix B requires that measures be provided for verifying or checking the adequacy of design, such as performance design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to the above, in June 2003, the licensee identified that their previous electrical distribution system calculation had not verified the adequacy of the design because with a LOCA with degraded voltage conditions, the potential existed for a voltage transient causing insufficient voltage to operate essential 480 VAC equipment. The licensee entered the issue into its CAP as CR 03-04435. The finding screened as having very low significance (Green) using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for the At-Power Situations," because the inspectors answered "no" to all five questions under the Mitigating Systems Cornerstone column of the Phase 1 worksheet.

- Contrary to 10 CFR 50.65(a)(4), licensee personnel performed scheduled activities without properly evaluating plant risk that resulted as an unplanned entry into a licensee yellow risk category. On January 30, 2006, for approximately 9 hours, licensee personnel entered yellow risk when bus F3 was removed for scheduled work without proper risk evaluation being performed. This issue is documented in CR 06-00254. This finding is of very low safety significance because the work activities did not represent a loss of safety function or loss of a safety train for greater than limits in TSs.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

B. Allen, Director, Plant Operation
J. Amidon, ECP Coordinator
M. Bezilla, Site Vice President
B. Boles, Manager, Plant Engineering
B. Cope, Senior Nuclear Technologist
C. Daft, Staff Engineer Technical Services
D. Dibert, Dry Cask Project Manager
A. Garza, Radiation Protection Supervisor
D. Gerren, Senior Consultant Engineer Technical Services
J. Grabnar, Manager, Design Engineering
L. Harder, Manager, Radiation Protection
D. Haskins, Manager, Leadership & Organizational Development
C. Hengge, Staff Engineer Plant Engineering
R. Hovland, Manger, Technical Services
R. Hruby, Manager, Nuclear Oversight
G. Kendrick, Acting Manager, Site Maintenance
D. Kline, Manager, Security
S. Loehlein, Director, Station Engineering
P. McClosky, Manager, Site Chemistry & TOP Team Manager Sponsor
G. Melssen, Site Maintenance Rule Coordinator
L. Myers, Chief Operating Officer, FENOC
D. Noble, Radiation Protection Supervisor
K. Ostrowski, Manager, Plant Operations
C. Price, Manager, Regulatory Compliance
R. Schrauder, Director, Performance Improvement
S. Slosnerick, Engineer Technical Services
P. Smith, Senior Nuclear Associate
J. Sturdavant, Senior Regulatory Compliance Specialist
M. Trump, Manager, Training
J. Vetter, Emergency Response Manager
G. Wolf, Regulatory Compliance

Ohio Emergency Management Agency
E. Edwards, Observer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Open

05000346/200600203	URI	Inoperability of EDG2 Due to Exhaust Valve Rocker Arm Damage

Open and Closed

05000346/2006002-01	FIN	Unqualified Examination of a Pressurizer Surge Line DM Weld
05000346/2006002-02	NCV	Failure to Expand Code Weld Examination Scope

Closed

05000346/2003-007-00	LER	AC System Shows Potential Loss of Offsite Power Following Design Basis Accident
05000346/2005-006-00	LER	SW38 Found Out of Position

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety, but rather that selected portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless stated in the body of the inspection report.

1R04 Equipment Alignment

CR 06-00648; Schedule Ties Broken For LLRT Project
DB-NE-03292; Core Alteration Prerequisites and Periodic Checks; Revision 04
DB-OP-06013; Containment Spray System; Revision 15
DB-OP-06316; Diesel Generator Operating Procedure; Revision 21
DB-PF-03008; Containment Local Leak Rate Tests; Revision 07
Drawing OS-005; Operational Schematic Containment Spray System; Revision 10
SD-022A; System Description of the Containment Spray System; Revision 03

1R05 Fire Protection

CR 06-00268; Early Removal of Insulation on Main Steam Pipe Activates Sprinkler
Davis-Besse Nuclear Power Station Fire Hazard Analysis Report
Davis-Besse Nuclear Power Station, Unit 1 - Exemption From The Requirements of 10 CFR Part 50, Appendix R, Section III.G.3 (TAC No. MC1833); Dated July 21, 2005
DB-FP-00005; Fire Brigade Drill Assessment; Revision 05
Drawing A-221F; Fire Protection General Floor Plan EL. 545' & 555'; Revision 7
Drawing A-222F; Fire Protection General Floor Plan EL. 565'; Revision 13
Drawing A-223F; Fire Protection General Floor Plan EL. 585'; Revision 17
Drawing A-224F; Fire Protection General Floor Plan EL. 603'; Revision 21
Drawing A-226F; Fire Protection General Floor Plan EL. 643'; Revision 12
Drawing E-930A; Emergency Battery pack Locations and Lamp Directions; Revision 05
Drawing PFP-S6-0000; Service Building 6, Laydown Area, Station Black-Out Diesel; Revision 03

1R07 Heat Sink Performance

CR 06-00779; Three Found Plugged In Containment Air Cooler E37-3
CR 06-01035; Tube Plugging Found In Containment Air Cooler #3 (E37-3)
CR 06-01346; CAC 3 Cooler Tube Inspection

1R08 Inservice Inspection Activities (IP 71111.08)

Corrective Action Program Documents
CR 02-08782; 1-CCA-3 Leak
CR 02-08795; 1-CCA-3 Leak
CR 05-00529: Eddy Current
CR 05-00735; OTSG 2-A Tube Crack.

CR 05-00874; OTSG 1-B Lower Tube End Crack
CR 05-00875; Double Tubesheet Rolls in OTSG 1-B Lower Tubesheet

Corrective Action Program Documents as a Result of NRC Inspection
CR 06-00866; Procedure Non-Compliance (Near Miss) - FANP Procedure 54-ISI-829-05
CR 06-00935; EDY Calculation Does not Satisfy NRC Order EA-03-009.
CR 06-01182; NRC ISI Further Documentation of CR 06-00972
CR 06-01183; NRC ISI Reportability of CR 02-08782

Corrective Action Program Documents for Evaluations for Boric Acid Leakage
CR 03-00461; Decay Heat Suction Valve from RCS.
CR 03-07864; Reactor Coolant System to Decay Heat System Isolation Bypass
CR 03-08516; RCS to DH System Isolation Bypass
CR 03-11428; DH21, RCS to DH System Isolation Bypass
CR 04-00938; DH21RCS to DH System Isolation Bypass
CR 04-04978; DH21RCS to DH System Isolation Bypass
CR 05-03411; DH21RCS to DH System Isolation Bypass

Documents Related to Pressure Boundary Welding
WPS A8-2-1, Gas Tungsten Arc Welding (GTAW) of Stainless Steel (P8), Groove with or Without Backing; Revision 2.
PQR No. 003; dated March 9, 1977.
PQR No. 007; dated March 31, 1977.
Radiographic Examination Data Sheet and Radiographic Records, MU3 FW-2, dated June 26, 2003.
Radiographic Examination Data Sheet and Radiographic Records, MU3 FW-3, dated June 26, 2003.
Weld Traveler,MU3 FW-2, dated June 24, 2003.
Weld Traveler,MU3 FW-3, dated June 24, 2003.

Documents Associated with Disposition of Relevant Indications
UT Vessel Examination Report; RC-PZR-WP-33-W/X; dated February 26, 2002.
MT Examination Data Sheet; SP-SG-1-2-WG-23-W/X; dated April 26, 2000.
MT Examination Data Sheet; SP-SG-1-2-WG-23-W/X; dated February 26, 2002.

Documents Associated with ASME Code Nondestructive Examinations Observed
54-ISI-829-05; Manual Ultrasonic Examination of Dissimilar Metal Piping Welds; dated March 7, 2006
54-ISI-240-43; Visible Solvent Removable Liquid Penetrant Examination Procedure; dated February 3, 2006

Documents Associated with Steam Generator Examinations
DBPM-SGMP-PE-001; Steam Generator Management Program Manual, Revision 6.
AREVA Document 54-ISI-400-14; Multifrequency Eddy Current Examination of Tubing; dated August 12, 2005.
AREVA Document 51-5058044-00; A CMOA Evaluation of Steam Generator Tubing at Davis-Besse, 14 MCO; dated March 31, 2005.

AREVA Document 51-5037188-003; Davis Besse Exceptions to NEI 97-06; dated February 10, 2006.
AREVA Document 51-9011789-002; Davis Besse Degradation Assessment for 14th Refueling Outage (March 2006); dated March 8, 2006.
AREVA Document 51-501884-004; Procedure for Selection of In-Situ Pressure Testing Candidates; dated February 10, 2006.
AREVA Document 51-5001484-04; Qualified Eddy Current Examination Techniques for Davis-Besse; dated February 10, 2006.
AREVA Document Examination Technique Specification Sheet (ETSS) No. 4; Sleeve rolls and parent tubing adjacent to the lower sleeve end; Revision 0.
AREVA Document ETSS No. 3; Rotating Probe (.080HF/+Point) Areas Obstructed with the 520PP probe; Revision 0.
AREVA Document ETSS No. 2; Rotating Probe (o.115/+Point/0.080HF), Tube Expansion, Lane and Wedge, Lower Tubesheet Crevice and Special Interest; Revision 0.
AREVA Document ETSS No. 1; Bobbin Standard ASME Code Examination for Unsleeved Parent Tubing; Revision 0.

Other Documents
Completed DB-PF-03010; RCS Leakage Test, dated September 26, 2003.
Completed DG-PF-03010; RCS Leakage Test; dated January 5, 2004.
EM-DP-01501; Boric Acid Corrosion Control Inspections; Revision 10.
NOP-ER-2001; Boric Acid Corrosion Control Program; Revision 5.

1R11 Licensed Operator Requalification Program

DBBP-TRAN-0017; Conduct of Simulator Training; Revision 01
OQR-INP-S111; Simulator Guide Title: Pressurizer Instrument Failure, LB LOCA with a Loss of DH Pump 1; Revision 01

1R12 Maintenance Effectiveness

CR 05-05413; Oil Discharge For Diesel Fire Pump Exhaust;
CR 05-05472; Fire Protection 5 Year Flow Test Results Do Not Meet Acceptance Criteria
CR 05-05572; Jockey Fire Pump Found Not Running
CR 05-05622; Fire Suppression System Pressure Gauges Are Regularly Out of Tolerance
CR 05-05734; Fire Protection Leak Request For Assistance
CR 05-05765; Fire Barrier 422A-F/422-C
CR 05-05930; Understanding Equipment Near EDG Fire Suppression Piping (NRC Identified)
CR 06-00334; Configuration Control Fire Protection Seismic 1 Piping
CR 06-00375; Missing Fireproofing
CR 06-00531; Door 306 Found Open (NRC Identified)
CR 06-00701; Maintenance Rule (A) (1) Evaluation For Doors
Davis-Besse Nuclear Power Plan Unit 1 Fire Hazard Analysis Report; Revision 20
D-B System Health Report; Third Quarter 2005
D-B System Health Report; Fourth Quarter 2005
Drawing OS 47A, Sheet 1; Station Fire Protection System; Revision 23

Drawing OS 47A, Sheet 2; Station Fire Protection System; Revision 09
Drawing OS 47A, Sheet 3; Station Fire Protection System; Revision 04
Drawing OS 47A, Sheet 4; Station Fire Protection System; Revision 08
Drawing OS 47A, Sheet 5; Station Fire Protection System; Revision 14
Listing of Work Orders for Fire Protection System, Doors and Hatches; March 2005 through March 2006; March 15, 2006
Technical Services Engineering - Programs Unit Quarterly Program Health Report, Fire Protection Program; Fourth Quarter 2005

1R13 Maintenance Risk Assessments and Emergent Work Control

CR 05-00060; DBC-2PN Battery Charger Float Adjustment Potentiometer
CR 05-05988; RCS 40 psig Pressure Drop/RC2 Cycle
CR 06-00154; #2 EDG Broken Parts in Rocker Arm Area
CR 06-00159; Abnormal Tapping Noise Observed in Vicinity of Cylinders #3, 4, and 5 on EDG #2
CR 06-00254; WW0605 F3 Outage Risk Evaluation
CR 06-00270; Work Week 606-Risk For BF3 Work Activities
DBBP-OPS-0003; On-line Risk Management Process; Revision 01
DBBP-PES-0007; Control of Monitoring Equipment; Revision 01
DB-OP-06319; Instrument AC System Procedure; Revision 13
DB-OP-06904; Shutdown Operations; Revision 21
DBBP-OPS-0003; On-Line Risk Management Process; Revision 02
DB-SC-03001; On-Site DC Bus Trains Lined Up, Available and Isolated (Mode 1, 2, 3, and 4); Revision 07
NG-DB-00001; On-line Risk Management; Revision 03
NOP-OP-1005; Shutdown Safety; Revision 09
NUMARC 91-06, Guidelines for Industry Actions to Assess Shutdown Management, December 1991
Drawing OS-060, Sheet 1; 250/125V DC and 120V Instrument AC System; Revision 14
Drawing OS-060, Sheet 2; 250/125V DC and 120V Instrument AC System; Revision 13
Problem Solving Plan for EDG #2 Abnormal Tapping Noise for CR 06-00159; 01/23/06
Problem Solving plan RCS 40 psig Pressure Drop/RC2 Cycle for CR 05-05988; 12/29/05
Shutdown Safety Report (SSR) 14th Refueling Outage, 2/23/2006
WO2001194465; Emergency Diesel Generator 1-2 Engine (CYL Head #4 Replacement)

1R14 Operator Performance During Non-Routine Evolutions and Events

CR 06-00440; CA 04-04087-18 Was Inappropriately Closed to CA 04-04087-22
CR 06-00488; MSSV SP17A9 Lifted Outside The Allowable As-Found Band
CR 06-00491; SP17A7 As-found Lift Test Pressure Not Within the Acceptance Range of + Or - 3 percent
DB-NE-06102; New Fuel Receipt, Inspection, and Storage
DB-NE-06101; Fuel/Control Component Shuffle; Revision 07
DB-NE-06300; Fuel Loading and Refueling Limits and Precautions; Revision 04
DB-OP-00030; Fuel Handling Operations; Revision 04
DB-OP-06002; RCS Draining and Nitrogen Blanketing; Revision 13
DB-OP-06904; Shutdown Operations; Revision 21

DB-PF-03001; Main Steam Safety Valve Setpoint Test; Revision 02
NOP-OP-1005; Shutdown Safety; Revision 09
14RFO-2: Contingency Plan for RCS Drain below Flange Level and Operation Below 80 Inches Above the RCS Hot Leg Centerline; 03/02/2006

1R15 Operability Evaluations

Calculation C-EE-024.01-010; Emergency Diesel generator Room Electrical Equipment Temperature Evaluation; Revision 00
Calculation C-FP-013.03-001; Fire Protection Compliance, Piping Length Determination; Revision 00
Calculation C-ME-024.02-003; Ventilation For EDG Panels C3617 and C3618: Revision 00
CR 04-00774; MTSV Test Trip “A” Light Did Not Immediately Come Back On - Repeat Failure
CR 05-00275; Failure of Master Trip Solenoid Valve “A” During Performance of DB-SS-04159
CR 05-03175; failure of Master Trip Solenoid “A” Indicating Light to Extinguish as Required
CR 05-03566; Test Trip “A” Indicating Light Discrepancy During Testing
CR 05-03765; MTSV “A” Light Failed to Extinguish When Initially Depressed
CR 05-03818; DB-SS-04159 24 VDC Test, “A” Pushbutton Problem
CR 05-05472; Fire Protection 5 Year Flow Test Results Do Not Meet Acceptance Criteria
CR 05-05802; MTSV “A” Failed Test Trip
CR 05-05838; Revision to OE 05-0013 Based On Investigation Of CR-05-05472
CR 06-00313; AFW Turbine #2 Did Not Respond to Speed Control signal From Control Room
CR 06-01136; EDG Acceptance Test: DB-SC-10002 Deficiency: C3617 Temperature Rise
DB-SP-04159; AFP 2 Monthly Test; Revision 06
NOP-OP-1010; Operational Decision-Making; Revision 00
ODMI Recommendation Summary Sheet for CR 05-05802
Operability Evaluation 05-0013; The Hazen-Williams coefficient (C factor) values for Attachments 4 and 5 of DB-FP-04035, 5 Year Flow Test, do not meet the minimum acceptance criteria; Revision 01
Operability Evaluation 06-001; Voltage Regulator Temperature Rise; 03/22/2006
Problem Solving Plan for CR 06-00313; Aux Feedwater Pump #2 Speed Control Issue; 02/07/2006
Revised NEI 97-04, Appendix B; Guidance and Examples for Identifying 10 CFR 50.2 Design Bases; November 1999
WO 2000143364 and WO 200143366 EDG 1 and 2 Exciter Modification, Diesel Missile Shield Grating Evaluation; 02/10/2006
WO2001196385; Troubleshooting #2 AFW Governor; 02/07/2006

1R17 Permanent Plant Modifications

Calculation C-CSS-061.01-009; Pipe Stress Calculation for Containment Spray Pump (P56-1) Cyclone Separators; Revision 01

CR 04-06173; PCR-Enhancement- Mod CS Pump Quarter Test for ECR 04-0271 Overpressure Protection
CR 04-06398; PCR/NR, Enhancement: Procedures Affected by ECR 04-0271-00
Drawing OS-005; Containment Spray System; Revision 11
Engineering Change Package ECR 04-0271-00; Containment Spray System Piping Thermal Pressure Relief Flow Path; Revision 05

1R19 Post-Maintenance Testing

CR 06-00114; RPS Channel 1: RCS Hot Leg Loop 1 Flow Shift Anomaly
CR 06-00136; Vendor Manual M-324AQ-331 Does not Reflect FCR 85-0103, Supp 1, Rev A
CR 06-00459; PSL4534C Has Signs of Poor Switch Contact
DB-MI-03057; RPS Channel 1 Calibration of Overpower, Power/Imbalance Flow, and Power/Pumps Trip Functions; Revision 17
DB-MI-03353; Channel Functional Test of PSL-4533C, 4534C, and 4535C Main Feed Pump 1 and 2 Turbine Hydraulic Oil Trip and Main Turbine Oil Trip ARTS Channel 3; Revision 04
DB-OP-06313; Diesel Generator Operating Procedure; Revision 20
DB-SC-03801; Emergency Diesel Generator 2 Overspeed trip test; Revision 01
DB-SP-03160; AFP 2 Quarterly Test; Revision 16
WO 200047671; Diesel Generator 1-2 Exhaust Cylinders Pyrometer
WO 200048962; EDG 2 75 Pound Spring Loaded Lube Oil
WO 200094754; Emergency Diesel Generator 1-2 Engine
WO200099801; ECR 04-0072-00 Perform Modification on EDG 2 Electrical Governor Controls
WO 200125726; Auxiliary Feed Pump Turbine 1-2
WO 200126415; PM5424/PSL4535C: Replace Snubber Main Turbine Channel 3
WO 200153506; PSL4534C Repair Fitting Leak, DB-MI-03553
WO 200193306; DB-RPS1RC150: Perform Module Calibrations

1R20 Refueling and Outage Activities

CR 06-00656; Issues Associated With Containment Closure Control (NRC Identified)
DB-OP-01003; Operations Procedure Use Instructions; Revision 06
DB-OP-06002; RCS Drain And Nitrogen Blanketing; Revision 13
DB-Op-06012; Decay Heat And Low Pressure Injection System Operating Procedure; Revision 25
DB-OP-06902; Power Operations; Revision 14
DB-OP-06903; Plant Shutdown and Cooldown; Revision 21
DB-OP-06904; Shutdown Operations; Revision 21
DB-PF-03270; Containment Atmosphere Closure Verification For Core Alterations; Revision 05

1R22 Surveillance Testing

CR-06-00368; DB-SS-03145 Visual Inspection (NRC Identified)
CR 06-00409; Required ECCS Integrated Leakage Inspection; 02/17/2006

DB-DP-00025; Requirements for Breaching the Control Room Pressure Boundary; Revision 01
DB-MI-03246; Channel functional Test an Devise Calibration of 83C-ISLSP9A8,A9,B6,and B7 SFRCS Steam Generator Actuation Channel 2 Level Inputs; Revision 06
DB-MI-03212; Channel Functional Test of SFRCS Actuation Channel 2 Logic for Mode 1; Revision10
DB-MI-03014; Channel functional Test of Reactor Trip Breaker C, RPS Channel 4 Reactor Trip Logic, and ARTS Channel 4 Output Logic; Revision 11
DB-PF-03011; ECCS Integrated Train Leakage Test; Revision 05
DB-PF-03008, Containment Local Leakage Rate Tests, revision 7
DB-PF-06704; Pump Acceptance Criteria Curves, CC 14.92h; Revision 15
DB-SC-04271; Station Black-Out Diesel Generator Monthly Test; Revision 07
DB-SP-03219; HPI Train 2 Pump and Valve Test; Revision 11
DB-SS-04151; Main Turbine Control Valve Test; Revision 06
DB-SS-04152; Main Turbine Combined Intermediate Valve Test; Revision 06
DB-SS-03145; Control Room Emergency Ventilation System (CREVS) Refueling Interval or Special Test Train 1; Revision 07
Drawing OS-003; High Pressure Injection System; Revision 28

1R23 Temporary Plant Modifications

Calculation C-NSA-011.01-006; Service Water System Flow Path change with Refueling Canal at 23 Feet; Revision 00
DB-OP-06261; Service Water System Operating Procedure; Revision 22
TM 05-0026; Reroute Service Water Return header to Support 14RFO Maintenance Activities; Revision 00 and 01

1EP2 Alert and Notification System (ANS) Testing

Conference Call Documentation; Licensee, Ohio Emergency Management Agency, Ottawa County Emergency Management Agency, and FEMA Region V Staffs; Proposed Re-location of Two EPZ Sirens; dated December 19, 2005
CR 04-01735; Power Loss to Three Sirens for About 100 Minutes On March 5, 2004 Due to Downed Power Line
CR 04-04143; One Siren Out of Service for About 10 days in June 2004 Due to Lightning Damage
CR 04-04458; On July 8, 2004, Identified One Siren's Belts Damaged by a Squirrel and a Power Loss to Another Siren
CR 04-07860; Loss of Power to Two Sirens in Mid-December 2004 Due to Blown Fuses
CR 05-02788; Lightning Damage to Two Sirens in Mid-May 2005
CR 05-01610; Failed Batteries Identified on Two Sirens in July 2005
Internal Memorandum; December 2004 Biennial Prompt Notification System Siren Acoustic Testing
Internal Memorandum; Siren System Software and Firmware Upgrades; dated July 19, 2005
Internal Memorandum; Davis-Besse Prompt Notification System Roles and Responsibilities; dated November 15, 2005

Letter; FEMA Region V to Ohio Emergency Management Agency; Approvals of Proposed Changes to ANS Test Program and EPZ Sirens' Alternate Activation Station; dated June 10, 2005
Letter; FEMA Region V to Ohio Emergency Management Agency; Updates to the 1987 Design Report for the Davis-Besse Station's Prompt Notification System; dated October 10, 2005
RA-EP-00400; Prompt Notification System Maintenance; Revision 4
RA-EP-00420; Response to Prompt Notification System Malfunction; Revision 3
RA-EP-04400; Prompt Notification System Tests; Revision 8
Records of 2004 and 2005 Annual Preventive Maintenance on EPZ Sirens

1EP3 Emergency Response Organization (ERO) Augmentation Testing

CR 04-02853; Four ERO Support Positions Not Filled During April 2004 Augmentation Drill
CR 04-02882; Five of 37 On-Call ERO Positions Filled by Other Qualified Personnel During April 2004 Augmentation Drill
CR 04-02945; Review Emergency Plan Table 5-1 ERO Augmentation Commitments Versus Response Facility Implementing Procedures for Consistency
CR 04-04180; Determine Why Some Response Facility Activation Targets Were Not Met During April 2004 Augmentation Drill
CR 04-02877; JPIC Activation Was 5 Minutes Late During April 2004 Drill Due to Ongoing Equipment Setups - Reassess Implementing Procedure's Equipment Setup Expectations
CR 04-05222; About 50 Percent of On-Call ERO Positions Were Filled by Qualified Alternates During August 2004 Augmentation Drill
CR 05-04361; Two Support Positions Not Filled During August 2005 Augmentation Drill
DBBP-EMER-0006; ERO Guidance for Emergency Response; Revision 2
Emergency Plan Table 5-1; Manpower, Location, and Response Considerations for Emergencies; Revision 24
Emergency Plan Telephone Directory; Revision 88
Internal Memoranda; Results of Semi-Annual, Unannounced, Off-Hours ERO Augmentation Drills Conducted in March 2004, August 2004, February 2005, and August 2005
Internal Memorandum; Preliminary Results of the April 22, 2004 Unannounced, Off-Hours, Come-In Drill; dated May 3, 2004
Internal Memorandum; Emergency Response Organization Expectations; Revision 1; dated August 10, 2004
RA-EP-00100; Emergency Plan Training Program; Revision 10
RA-EP-00510; Maintenance of the Emergency Plan Telephone Directory; Revision 2
RA-EP-00550; Computerized Automated Notification System; Revision 3
RA-EP-02230; Dose Assessment Center Activation and Response; Revision 2
RA-EP-02260; Radiological Controls in the Davis-Besse Administration Building; Revision 4
RA-EP-02310; TSC Activation and Response; Revision 4
RA-EP-02410; OSC Activation and Response; Revision 9
Random Sample of 36 Key and Support ERO Members' EP Training Records

1EP4 Emergency Action Level (EAL) and Emergency Plan Changes

RA-EP-01500; Emergency Classification; Revision 5, dated August 31, 2005
10 CFR 50.54(q) Internal Review and Approval Records for Revision 5 of Implementing Procedure RA-EP-01500; dated August 22, 2005
Seven Letters to Ottawa and Lucas County Officials; Annual Review of the Davis-Besse Nuclear Power Station Emergency Action Levels; dated December 19, 2005
Three Letters to State of Ohio Officials; Annual Review of the Davis-Besse Nuclear Power Station Emergency Action Levels; dated December 20, 2005

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

CR 04-03511; Determine Why All Equipment Operators Remained at Scene of Simulated Medical Emergency During Medical Drill Portion of Integrated Facility Drill
CR 05-02036; Improve Decision Makers' Criteria for Making Notifications of a Minor Release in Progress During an Emergency Event
CR 05-02330; Controller Performance and Scenario Concerns Identified During April 2005 Integrated Facility Drill
CR 05-02332; Concerns Identified in TSC Critique of April 2005 Drill
CR 05-02357; Concerns Identified in EOF Critique of April 2005 Drill
CR 05-02844; Obtain EPZ Siren Coverage Map for Use as a Media Briefing Aid
CR 05-02851; Concerns Identified in EOF Critique of May 2005 Exercise
CR 05-02855; Concerns Identified in TSC Critique of May 2005 Exercise
CR 05-02865; Revise TSC Activation and Response Procedure to Include Guidance on Invoking 10 CFR 50.54(x)
CR 05-02888; Assess Apparent Inconsistent Information from OSC Management and the Shift Manager on Simulated Valve Manipulations During May 2005 Exercise
CR 05-05419; Improvement Items Identified in OSC Critique of October 2005 Drill
CR 05-05598; Assess Adequacy of Procedural Guidance on Content of Integrated and Functional Drills' Critique Reports
Emergency Plan Section 8.1.2; Drills and Exercises; Revision 24
EP Program Review Sections of Davis-Besse Oversight Staff's Quarterly Assessment Reports for 2004 and 2005
Internal Memorandum; May 20, 2004 Integrated Drill Report; dated August 31, 2004
Internal Memorandum; Preliminary Results of the April 19, 2005 Integrated Drill; dated May 9, 2005
Internal Memorandum; May 17, 2005, Exercise Report; dated June 28, 2005
Internal Memorandum; Preliminary Results of the September 1, 2005, Integrated Drill; dated September 30, 2005
Internal Memorandum; Preliminary Results of the October 6, 2005 Integrated Drill; dated November 7, 2005
Letters from Licensee Management to State of Ohio, Ottawa County, and Lucas County Emergency Management Agency Officials; Assessment of Interfaces with State and local Governments; dated November 2004 and November 2005
RA-EP-00200; Emergency Plan Drill and Exercise Program; Revision 6
Scenario Manual for Integrated Response Facility Drill on April 19, 2005
Scenario Manual for Integrated Response Facility Drill on May 20, 2004
Scenario Manual for Integrated Response Facility Drill on October 6, 2005

December 2004 Post Accident Sampling System Drill Report; dated February 2, 2005
November 2005 Alternate Reactor Coolant Sampling System Drill Report; dated December 23, 2005
2004 Offsite Radiation Monitoring Team Drills Report; dated November 30, 2004
2005 Offsite Radiation Monitoring Team Drills Report; dated December 30, 2005

2OS1 Access Control to Radiologically Significant Areas: and
2OS2 ALARA Planning And Controls

CR06-00843; Dosimeter Dose Rate Alarm
CR05-05021; RFA To Evaluate Shielding On DH Line In ECCS 1
CR05-05068; Individual Received Dose Rate Alarm
CR05-05679; Exit Whole Body Count Not Performed
CR05-05806; Dose Rate Alarm
CR06-00374; RP Procedure Discrepancies
CR06-00959; HRA Found During Normal Sump Survey
DB-HP-01152, "Performance Of High Exposure Work"; Revision 6;
Davis-Besse Dose Reduction 5 Year Plan
Fleet Oversight Audit Report (April 1 - June 30, 2005); dated July 27, 2005
Fleet Oversight Audit Report (July 1 - September 30, 2005); dated October 27, 2005
RWP 2006-5104; Reactor Head Disassembly/Reassembly Work Activities; Revision 0
RWP 2006-6006; Radiography In The Decay Heat Cooler Room; Revision 0
RWP 2006-5401; RCP 2-1 & 2-2 Inspection And Replacement Activities; Revision 0
RWP 2006-5300; Steam Generator Work Activities; Revision 0

4OA1 Performance Indicator (PI) Verification

CR 06-00370; Minor Error Identified in Some 2005 ERO Performance Indicator Data Identified in Early February 2006 Due to Change Implemented in December 2005 to the Shift Manager Qualification Program
DBBP-EMER-0002; NRC Performance Indicator for ERO Drill Participation; Revision 3
DBBP-EMER-0003; NRC Performance Indicator for ANS Reliability; Revision 4
DBBP-EMER-0004; NRC Performance Indicator for Drill and Exercise Performance; Revision 1
DBBP-RC-0005; Performance Indicator Coordinator Duties; Revision 0
Internal Memoranda; Monthly Submittals of NRC Performance Indicator Opportunities and Supporting Records; April 2005 through December 2005

4OA2 Identification and Resolution of Problems

Root Cause Analysis Report of CR 06-00154; Discovery of Damaged Components in Emergency Diesel Generator 2; February 17, 2006
CR 06-00159; Tapping Nosie on EDG2 During Testing Following Maintenance
CR 06-00154; No. 2 EDG Broken Parts in Rocker Arm Area
DB-MM-09320; Emergency and Station Blackout Diesel Engine Maintenance; Revision 10

4OA3 Event Followup (71153)

CR 02-07646; SSDPC - Calc C-EE-004.01-05 Temperature Variation not Considered
CR 03-04435; Preliminary Davis-Besse AC System Analysis Results
CR 03-05347; PCR:DB-SC-03023 - To Incorporate ECR 03-0339-00
CR 06-00162; Documentation of NRC Notification for Security Event
DBBP-LP-1651; Security Contingency Checklists; Revision 1
DBBP-LP-1851; DBNPS Security Defensive Strategy; Revision 4
DBBP-LP-1852; Threat Advisory Protective Measures; Revision 01
IS-DP-08500; Armed Response Force; Revision 04
LER 05000346/2003-007-00, AC System Shows Potential Loss of Offsite Power Following Design Basis Accident
LER 05000346/2005-006-00: SW38 (Service Water) Found Out of Position
NOP-LP-1002; Fitness For Duty Program; Revision 3

4OA5.1 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

AREVA Document; 54-ISI-367-07; Visual Examination for Leakage of Reactor Head Penetrations; dated September 14, 2004
AREVA Document; 54-ISI-30-03; Written Practice for the Qualification and Certification of NDE Personnel; dated June 21, 2004
Reactor Head Nozzle Penetration Remote Visual Inspection Plan for Davis Besse Unit 1; dated January 3, 2005
EPRI Report 1006296; Visual Examination for Leakage of PWR Reactor head Penetrations on Top of RPV Head, Revision 2
NDE Certification Record, W. Persinger (VT-2 Bare Head), dated March 3, 2006
6027636A; Reactor Head Nozzle Penetration Remote Visual Inspection Plan; Revision 2
CR 03-08659; CCW connection to CRDMs
CR 04-03517; Reactor Vessel Head
CR 05-00666; Reactor Vessel Control Rod Nozzle Penetrations
CR 06-00807; Spare CRD B47-15 Vent Isolation Valve had Boric Acid Deposits
Calculation C-ME-099.99-013; Effective Degradation Years (EDY) Calculation per Alloy 600/82/182 PWSCC Susceptibility Determination Related Application, Revision 0
Calculation C-ME-099.99-013; Effective Degradation Years (EDY) Calculation per Alloy 600/82/182 PWSCC Susceptibility Determination Related Application, Revision 1
Completed copy of 6027636A; Reactor Head Nozzle Penetration Remote Visual Inspection Plan; dated March 17, 2006

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agency-wide Document Access and Management System
AFI	Area For Improvement
AFW	Auxiliary Feedwater
ALARA	As Low As is Reasonably Achievable
ANS	Alert and Notification System
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Corrosion Control
CAC	Containment Air Cooler
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CR	Condition Report
DBBP	Davis-Besse Business Practice
DM	Dissimilar Metal
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EAL	Emergency Action Level
ECR	Engineering Change Request
EDG	Emergency Diesel Generator
EDY	Effective Degradation Years
EOF	Emergency Operations Facility
EP	Emergency Preparedness
EPRI	Electric Power Research Institute
EPZ	Emergency Planning Zone
ERO	Emergency Response Organization
ET	Eddy Current
FEMA	Federal Emergency Management Agency
FENOC	FirstEnergy Nuclear Operating Company
HRA	High Radiation Area
IMC	Inspection Manual Chapter
INPO	Institute of Nuclear Power Operations
IR	Inspection Report
ISI	Inservice Inspection
JPIC	Joint Public Information Center
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MSIV	Main Steam Isolation Valve
MT	Magnetic Particle
MTSV	Master Trip Soleniod
NCV	Non-Cited Violation
No.	Number
NRC	United States Nuclear Regulatory Commission
NUREG	Nuclear Regulatory Guide
OSC	Operations Support Facility
PARS	Publicly Available Records
PI	Performance Indicator

PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RCS	Reactor Coolant System
RP	Radiation Protection
RWP	Radiation Work Permit
RVCH	Reactor Vessel Closure Head
SDP	Significance Determination Process
SG	Steam Generator
SSDPC	Safety System Design and Performance Capability
TI	Temporary Instruction
TS	Technical Specification
TSC	Technical Support Center
URI	Unresolved Item
USAR	Updated Safety Analysis Report
UT	Ultrasonic Examination
VAC	Voltage Alternating Current
VHP	Vessel Head Penetration
WO	Work Order