From: Elaine Raphael
To: Joelle Starefos; Robert Haag; Russ Bywater
Date: 8/29/02 1:37PM
Subject: draft report

Attached are the sections, appendices and figures of the draft report.

Reminder: please send me your references. Remember to put titles and dates. See Appendix C - Ed or Tom's section for an example of the information needed.

have a great weekend
e.

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NRC PREDECISIONAL

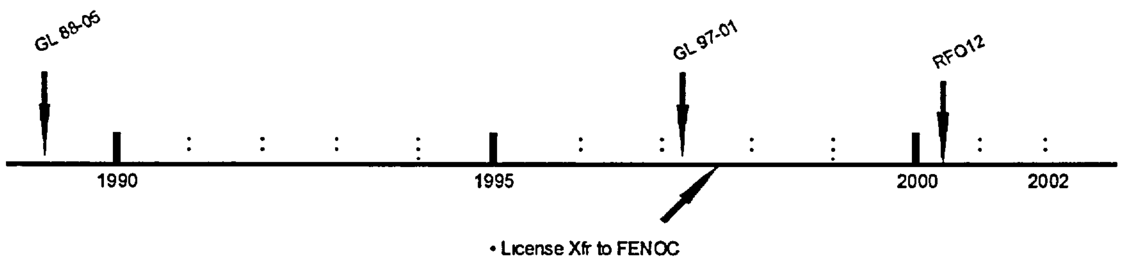

Figure 3.4-1
NRC and Industry Failed to Establish Adequate Requirements and Guidance

NRC PREDECISIONAL

3. REVIEW

As a central focus of the review of the NRC's regulatory processes relative to the DBNPS event, the task force sought to answer the fundamental question of why this event was not prevented. While this focus was introspective in nature, the task force could not answer this question without recognizing and considering the licensee's safety performance relative to this event.

Fundamentally, this event occurred because both the NRC and nuclear industry failed to fully appreciate the underlying significance of VHP nozzle cracking and boric acid corrosion. This may seem counter-intuitive given the extensive amount of domestic and foreign industry operating experience, as well as research, available that illustrate the nature and extent of both these generic problem areas.

From a review of this operating experience in the early 1990s, including the ensuing research activities, the NRC and nuclear industry concluded that Alloy 600 VHP nozzle cracking was not an immediate safety concern. This conclusion was predicated on the belief that cracking associated with Alloy 600 VHP nozzles was essentially limited to axial cracks. These axial cracks would grow very slowly (i.e., many years) and would not (or at a minimum be extremely unlikely) lead to rapid failure or gross rupture of the nozzle or significant wastage of the RPV head from boric acid corrosion before such a leak would be detected by GL 88-05 inspections of the RPV head for boric acid deposits. Because of this belief, both the NRC and industry philosophy and approach to addressing this issue became one of reactor coolant pressure boundary (RCPB) leakage management rather than one of RCPB leakage prevention. Since Alloy 600 VHP nozzle cracking is virtually a statistical certainty, the implication of a management by leakage approach is that all PWRs will be operated sooner or later in violation of NRC requirements which proscribe RCPB leakage during power operations. Another outcome of the view that the issue was not an immediate safety concern, heretofore, has been the acceptance of the existing inspection requirements and guidance, which only involve visual inspections of the RPV head. Visual inspections are not effective in characterizing the extent of nozzle cracking.

Additionally, the task force identified four contributing causes. First, the NRC and licensee did not adequately assess relevant industry operating experience and research. Second, the licensee did not assure that plant safety issues received the appropriate attention. Third, the NRC missed many opportunities to have identified the VHP nozzle leaks or RPV had degradation. Fourth, the NRC and industry did not establish adequate requirements and guidance.

3.1 The NRC Failed to Adequately Assess Operating Experience Relevant to Alloy 600 Nozzle Cracking and Boric Acid Corrosion of Carbon Steel Components

Deficiencies in a number of NRC programs and their implementation contributed in combination to a mistaken conclusion regarding the safety significance of vessel head penetration degradation and the potential for major damage to reactor pressure vessel (RPV) heads. The Task Force found such deficiencies in the NRC closeout and follow up on generic communications, Generic Issues Program, and the NRC follow up of industry generic responses to technical and safety issues.

Despite the large accumulation of data on primary system leakage and boric acid corrosion of carbon steel components, timely corrective action to address boric acid buildup on the Davis-Besse Nuclear Power Station (DBNPS) reactor pressure vessel head was not taken. Both the NRC and industry has obtained a significant amount of operating experience regarding boric acid leakage and corrosion of carbon steel components. For example, since 1980, 17 NRC generic communications have been issued providing examples of events involving either primary system leakage or corrosion of primary system components. Numerous events contained in licensee event reports include leakage from pressurizer instrumentation, pressurizer heater sleeves, reactor coolant system instrumentation, control rod drive mechanism penetrations, excessive corrosion of fasteners on valves and the reactor head, reactor coolant system nozzles, pump casings, primary system piping, and miscellaneous component parts corroded by boric acid deposits. In addition to numerous primary system leaks, there have been pressurizer vessel base metal wastage events, and reactor pressure vessel head wastage. The significance of many of these events were either lost or forgotten when making an assessment of DBNPS.

3.1.1 Significant Operating Experience Exists for Primary System Leakage and Boric Acid Corrosion

A review of operating experience relevant to boric acid leakage and corrosion in PWRs was accomplished for the period 1986 through the first quarter of 2002. This information was entered in a database which was then sorted to determine any trends and patterns. Licensee Event Reports (LERs) were the basic source of boric acid leakage events. Two additional events were added to the database because they involved boric acid leakage and reactor pressure vessel (RPV) head wastage, but were not recorded in a licensee event report (LER). For the period of interest, 73 Pressurized Water Reactors (PWRs) were included in the sample. NRC generic communications relevant to boric acid issues that were issued since 1980, were also reviewed to determine what guidance was provided to the industry, and whether or not this guidance was utilized by DBNPS. Each operating experience document may have discussed more than one component, system, or was applicable to more than one unit. Besides listing the component that was affected by the boric acid leak, other information was sorted by Nuclear Steam System Supplier (NSSS) designer, design type, plant operating age, number of operating years at the time of the event report, and year of occurrence.

The majority of primary system leakage events and boric acid corrosion events listed in this report come from domestic operating experience. Although there are several events that have occurred at foreign plants, detailed information at foreign events is generally not available, and most of the data is restricted and cannot be published. As seen in this report, age and material condition of power plants plays a significant role. Appendix E of this report contains an analysis of domestic operating experience related to primary system leakage and boric acid corrosion from 1986 through the first quarter of 2002. In determining the correlation between age an event types, many of the figures have been plotted against the number of years of operation prior to the event date. In addition to data obtained in licensee event reports (LERs), NUREGs (NRC technical reports) have been also been issued dealing with boric acid corrosion and cracking of nozzle penetrations.

(1) Babcock and Wilcox and Combustion Engineering Plants Are Highly Susceptible to Boric Acid Leakage and Corrosion

Babcock and Wilcox (B&W) and Combustion Engineering (CE) plants appear to be highly susceptible to boric acid leakage and corrosion. One hundred percent of B&W plants have reported boric acid related problems. Given the high incidence rate of boric acid leakage problems at B&W plants, DBNPS should have been alerted and taken appropriate corrective actions prior to the discovery of the RPV corrosion by leaking vessel head penetrations (VHPs) in February 2002.

(2) Control Rod Drive Mechanism Leakage Is Dominated by B&W Plants

B&W designed plants dominate control rod drive mechanism (CRDM) leakage. There were 15 documents relating to CRDM leakage of which 10 occurred at B&W plants. When considering that B&W plants make up less than 10 percent of the plants within the sample of 73 PWRs, the B&W plants are greatly over-represented. The types of boric acid leakage events occurring at B&W plants include CRDM nozzles (dominant failure), and CRDM flanges and fasteners. Combustion Engineering (CE) plants were second to B&W plants with three reports documenting boric acid leakage of CRDM seal housings.

(3) Extensive Control Rod Drive Mechanism Nozzle Cracking and Leakage at B&W plants

As a group, B&W plants have had 6 percent of their CRDM penetrations develop through wall cracks, 100 percent of B&W plants have experienced axial CRDM penetration cracks, and 86 percent of B&W plants have experienced circumferential cracking in at least one CRDM penetration. The average number of operating years prior to CRDM cracking and leakage discovery ranged between 17 and 27 years. DBNPS was the last B&W unit to report cracking and leakage (February 2002). Oconee 1 reported leakage in December 2000, Oconee 3 in March 2001, Oconee 2 in April 2001, Crystal River 3 in October 2001, Three Mile Island 1 in October 2001, and Oconee 3 made an additional report in November 2001. Based on information gathered from DBNPS, DBNPS probably should have been the first B&W unit to report CRDM cracking and leakage. The licensee for DBNPS relied substantially on industry susceptibility models to postpone VHP nozzle inspections. As shown from the operational experience data, DBNPS was within the average operating time period to expect CRDM penetration cracking and leakage. The industry average operating time for CRDM penetration leakage is 21.6 years.

(4) Reactor Pressure Vessel Metal Wastage Events Caused by Boric Acid Corrosion

DBNPS was the third plant to report RPV wastage caused by boric acid corrosion. Previous events include the Turkey Point 4 event in March 1987, and the Salem 2 event in August 1987. The Turkey Point 4 and Salem 2 events and their lessons learned from

1987 should have been an indicator to DBNPS that RPV wastage from boric acid accumulation was possible, and should have been included in their Boric Acid Corrosion Control (BACC) program. Information gained through interviews of engineers and managers at DBNPS (also the NRC), indicated that a mind set had developed that boric acid corrosion on the RPV head was not a credible event because of its elevated temperature.

(5) Pressurizer Vessel Wastage Events Caused by Boric Acid Corrosion

There have been three events involving pressurizer vessel wastage. All of these events have occurred at CE plants (Arkansas One 2, San Onofre 2, and San Onofre 3). These events and their lessons learned in conjunction with RPV wastage events do indicate that boric acid corrosion of high temperature components is possible, and should be assessed further.

Recommendations:

[62] Consider providing an integrated listing of studies or major documents containing significant operating experience to ensure that this body of knowledge and experience isn't lost.

[81] Consider providing an integrated listing and assessment of issued generic communications including an assessment of their effectiveness.

[124] Consider studying the unique vulnerabilities of B&W plants with respect to nozzle cracking and boric acid corrosion.

[27] Consider performing a study to analyze boric acid corrosion of different materials under varying temperatures and conditions.

[52] Consider the need for long-term analysis of operational experience by a single group.

3.1.2 NRC Operating Experience Review and Assessment Capability Has Diminished

Longer term operating experience reviews were accomplished by the Office for Analysis and Evaluation of Operational Data (AEOD) until 1999. AEOD was originally established as a lesson learned from the accident at Three Mile Island in 1979. To gain efficiencies, AEOD was eliminated and many of the responsibilities and authorities of AEOD were transferred to other NRC offices. The main responsibility for accomplishing operating experience reviews (both domestic and foreign) was given to the Office of Nuclear Reactor Regulation (NRR). However, most operating experience reviews done by NRR involve domestic current events, and do not involve review and assessment of operating failure trends or lessons learned of either domestic or foreign events. In addition, the Task Force has determined through interviews with NRR management, that NRR has not yet decided the scope of operational experience reviews. MD 8.5, "Operational Safety Data Review," still contains references to reviews by AEOD. NRR took over the procedure in 1999 and hasn't updated the Directive to agree with operational experience reviews that are now controlled by NRR.

(1) "Report of the Review of Operational and Occupational Event Review, Evaluation, and Followup," Issued on August 1, 1994, Contained Many Recommendations. This report reviewed the level of support for NRC operational experience reviews and assessments and made recommendations reduce duplication of effort and to improve communications. The report indicated that approximately 178 direct full-time equivalent (FTE) employees were used to evaluate operational experience (53 in NRR, 84 in the Regions, 37 in AEOD, 1 in the Office of Nuclear Regulatory Research (RES), 2 in the Office of Nuclear Material Safety and Safeguards (NMSS) and <1 in the Office of State Programs (OSP).

1994 Major Report Observations and Recommendations:

- Unnecessary Overlap and Duplication, Multi-office Review of the Same Types of Events and Operational Data
- Should Develop a Human Factors/performance Program
- Increase the Benefit from the Use of Risk Assessment Tools
- Reduce the Level of Involvement of AEOD in Day-to-day Aspects of Event Followup
- Have Early Coordination of Staff Efforts on Information Notices to Regional and Headquarter's Personnel to Assure That Staff Efforts Are Not Duplicated
- Consolidate as Many Event Databases as Practicable
- Consolidate Various Agency Reports, Such as Preliminary Notifications, Morning Reports, Daily Staff Notes and Highlights, Etc. into a Single System
- Revise MD 8.5, "Operational Safety Data Review," to Reflect Current Responsibilities and Authorities

Additional Insights Provided in the 1994 Report:

- Unnecessary overlap and duplication stem primarily from a lack of coordination or communication, weak guidance, a lack of guidance or systems, not properly implementing existing guidance, and/or weaknesses associated with information management.
- Overlap in the review and assessment of operational experience may be positive
  * Reduces the Likelihood That a Particular Event or Condition Will Not Be Handled Properly
  * Provides Oversight of the Implementation of Regional Programs
  * Provides Independent Quality Assurance by AEOD
  * Provides a Means of Diversity of Views in the Decision Making Process

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* Specialized Resources May Be Called on to Assist

* Provides a Means of Rapid Dissemination of Important Information to the Commissioners, Appropriate Managers, and Staff

(2) "Self-Assessment of Operational Safety Data Review Processes," issued on December 17, 1998, contained many recommendations. Evaluations and recommendations contained in this report are made for each function in the agency-wide events assessment and review of operational data - products, services, databases, and processes. Each function was examined to determine if it was needed to meet NRC strategic goals and if improvements in effectiveness or efficiency were warranted. The focus of the self-assessment was on headquarter's functions and processes. Regional contributions to the operational safety data review process were primarily in the event reporting and followup part of their inspection role The regions were not directly included in the scope of the self-assessment and no significant regional recommendations were made, because it was expected that ongoing review of the reactor oversight program, including assessment and inspection using risk-informed methods, would have a larger impact on the regions' event reporting and followup processes

This report indicates that there was a approximately 25% reduction in FTE (174 to 126.5) performing nuclear power plant operational data reviews and assessments between the assessment performed in 1994 and the current assessment performed in 1998. An additional 10.5 FTE were recommended to be deleted.

<u>1998 Report Recommendations include</u>:

- Reducing the Number of Bulletins and Generic Letters to Save FTE
- Keeping the Same Budget for Reactive Inspections Such as Augmented Inspection Teams (AITs), Incident Investigation Teams (IITs), Special Inspections
- Information Notices (INs) Should Be Continued but the Threshold Should Be Raised Which Would Save about 0.5 to 1 FTE
- Reliability and Risk Study Reports Have Medium Contribution to NRC Strategic Goals So it Was Recommended That They Should Stay, but That the NRC Should Work with the Industry to Avoid Duplication of Effort
- Risk-based Performance Indicators Were under Development, but Should Be Kept, but That the NRC Should Work with Industry to Avoid Duplication of Effort
- Accident Sequence Precursor (ASP) Was a Medium Contribution to NRC Strategic Goals, That Should Be Kept
- Performance Indicator Reports Should Be Kept and Was Seen as a Medium Contribution to NRC Strategic Goals
- Sunset the AEOD Annual Report Which Summarized Operating Experience Feedback, Reliability and Risk Activities, Generic Event Studies, Operating Experience Data,

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Incident Responses, Incident Investigation Program (IIP) Info, Independent Safety Assessments, and International Exchange of Information

- Sunset the Significant Event determination since risk-based performance indicators (PIs) are being developed

- Maintain the Operating Reactors Briefings, but Raise the Threshold to Save FTE

- Sunset AEOD Management Briefings Following the Daily Event Screening Call

- Generic Safety Issue Identification Should Be Done via MD 8.5, "Operational Safety Data Review"

- Sunset Any Input to the Department of Energy Office of Emergency Management Regarding Reactor Events

- Maintain the Reliability and Availability Data System (RADS) Which Will Be Used to Develop Risk-based Performance Indicators

- Maintain the Human Factors Information System Database (HFIS) in NRR

- Maintain the Risk and Reliability Databases (Accident Sequence Precursor (ASP), Common Cause, Initiating Events, Loss of Offsite Power, etc.)

- Maintain the Sequence Coding and Search System (SCSS) Database

- Sunset the Human Performance Event Database

- Sunset the Work Assignment Management System Database (WAMS) Which Tracked LER Assessment

- Transfer the Foreign Reactor Operating Experience, IRS Reports, to NRR

- Maintain Event Followup by NRR to Determine the Need for Additional Generic Action

- Maintain the Region/NRR Morning Calls to Discuss Emergency Notification System (ENS) and Other Information

- Maintain Regulatory Effectiveness capabilities in AEOD (now in RES)

- Sunset Routine Event and Inspection Report Screening by AEOD and NRR. This Function Would Be Done by the Regions

- Sunset the NRR Risk Assessment Contract with Pacific Northwest National Laboratory to Perform probability risk assessment (PRA) of Operating Events (Some Duplication of ASP)

- Sunset the Events Assessment Panel (Originally Made up of NRR, AEOD, and RES) and Use Alternatives to Ensure Consistency in Generic Communications

- Sunset Centralized Screening of LERs, Institute for Nuclear Power Operations (INPO) Documents, and Inspection Reports by AEOD. The Regions Will Refer Potentially Significant Generic Issues to the Appropriate Lead Office (NRR) for Action

(3) AEOD functions to be placed in other NRC offices. Staff Requirements - SECY-98-228 - "Proposed Streamlining and Consolidation of AEOD Functions and Responsibilities," provided guidelines for placing AEOD functions in other NRC program offices. SECY-98-228 indicated that the Commission had approved the staff's plan to streamline AEOD and consolidate its functions in other program offices. The SECY also indicates that "It is important that these functions continue with a degree of independence and , in particular, remain independent of licensing functions. The Office of Research should provide focused analysis of the operational data and not expend scarce resources on those operational incidents that are not risk significant."

Recommendations:

[9] Consider the need for the NRC to review industry guidance documents

[22] Consider a periodic review of the status of generic communications.

[13] Consider changes to MD 6.4, MD 8.5, and LIC-503 to coordinate office functions and provide appropriate training.

[61] Consider providing training on significant operational experience.

[46] Assess the need to enhance the use of foreign operating experience.

[77] Enhance the dissemination of foreign experience.

[78] Update the international experience database originally kept by AEOD.

[109] Assess whether or not lessons learned have been learned or not.

3.1.3 Generic Communication Program Implementation Inadequacies

The NRC did not adequately follow up on information, actions, or recommendations provided to licensees in NRC generic communications regarding primary system leakage and boric acid corrosion. Without this mechanism of checking licensee performance in the area of boric acid corrosion control, the NRC did not adequately implement its programs to ensure effectiveness of generic communications. Sufficient information was issued by the NRC to alert licensees and the NRC to the potential for boric acid corrosion of carbon steel components. Numerous events have occurred since the early 1980s involving primary coolant leakage in PWRs. The primary system leaks occurred because of component failures involving material wastage by boric acid, or through stress corrosion cracking of materials and then subsequent material corrosion by boric acid. Some of these events formed the basis for NRC generic communications.

(1) Seventeen NRC Generic Communication documents have been issued (including supplements) by the NRC involving boric acid leakage or corrosion caused by boric acid

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deposits from 1980 through the first quarter of 2002 (See Appendix E for a complete listing of applicable NRC generic communications). All of these documents (Information Notices, Bulletins, and Generic Letters) were issued to provide information to the industry and the public concerning recent events of interest Some of the NRC generic communication documents (bulletins and generic letters) may have also requested that the addressees provide the NRC with requested information regarding plant specific conditions at their facilities, the existence (or non-existence) of certain programs, corrective action implementation status, and inspection status and findings. Many of the issued generic communications have alerted DBNPS and the industry to conditions that ultimately resulted in the severe corrosion of the RPV head at DBNPS over the last few years, and eventually discovered by DBNPS in February 2002.

(2) A review of LERs involving boric acid leakage and corrosion shows that several years elapsed (with relatively high numbers of primary system leakage or boric acid corrosion events) with no boric acid leakage or corrosion generic communications being issued by the NRC. For example, during the period 1989 through 1994, two INs were issued (IN 90-10 on PWSCC of Inconel 600, and IN 94-63 on boric acid corrosion of a pump casing). For period 1998 through 2000, no generic communications were issued involving boric acid leakage and corrosion. Appendix E provides examples of events occurring during these time periods, including steel containment vessel corrosion, multiple examples of fastener corrosion, tubing and piping failures, leaking penetrations, leaking instrumentation nozzles, leaking CRDM housings, leaking pressurizer heater sleeves, and leaking CRDM nozzles. Also occurring during this time period was the body-to-bonnet leak on DBNPS's pressurizer spray valve which resulted in a stand-down meeting, significant training on boric acid corrosion, and programmatic changes Due to the impact of the spray valve event, DBNPS made a subsequent presentation to EPRI on the significance of boric acid corrosion.

(3) Inspection procedures issued to evaluate effectiveness of licensees' programs to assess and feed back to plant staff operational experience information pertinent to plant safety were not effectively implemented. For example, Inspection Procedure (IP) 62001, "Boric Acid Corrosion Prevention Program," was issued in August 1991 to verify that a documented boric acid program existed, that procedural guidance to implement the program were adequate, and that the licensee was implementing their program. IP 62001 was deleted in September 2001 with the initiation of the Reactor Oversight Program. During the 10 year period that the procedure was in use, a total of 35 inspection hours were documented against Cook unit 1, San Onofre 2 and 3. Similarly, IP 90700, "Feedback of Operational Experience Information at Operating Power Reactors was originally issued in August 1991, and subsequently canceled in September 2001 with the initiation of the Reactor Oversight Program. With the exception of four plants (all located in Region I), very little operational experience inspections were completed for the period 1991 through 1999. Had these inspections been performed for significant INs, Bulletins, and Generic Letters relating to boric acid leakage and corrosion, discovery of implementation weaknesses within either the NRC or licensees may have led to programmatic and plant changes.

(4) The NRC closeouts of GL 88-05 did not fully assess the implementation of the generic letter at DBNPS nor did the NRC sufficiently monitor licensee implementation following issuance of the closeout letter. A Temporary Instruction was not issued to support

implementation or closeout of GL 88-05. NUREG/CR-5576, "Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Plants," issued in 1990, recorded the review of licensee responses to GL 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants" and the results of 10 audits of boric acid control programs. Eight of the 10 plants audited were rated as "Satisfactory." Two plants were rated "Good." None of the plants audited were rated "Excellent " The NRC audit was conducted by NRC staff with contractor support and focused on reviews of program documents and discussion with plant personnel and included a plant tour of accessible areas. The DBNPS program was found to be sufficient, but enhancements in two areas were recommended: that formal training be provided for personnel conducting boric acid inspections, and that inspections be formally documented. The task group found no evidence that the NRC conducted a follow up verification to determine if the suggestions were implemented DBNPS's Boric Acid Corrosion Control program was lacking in both scope and followup from its initial issuance in 1989 through the outage in 2002. The licensee was in the process of making improvements in the program during the Task Force assessment period.

(5) The NRC closeouts of GL 97-01 did not fully assess the implementation of the generic letters at Davis Besse nor did the NRC sufficiently monitor licensee implementation following issuance of the closeout letter. A Temporary Instruction was not issued to support implementation or closeout of GL 97-01. Closeout of GL 97-01 for DBNPS appears to be based on assessment of generic program and FENOC's adoption of the program. Further, the NRC closeout does not indicate that any independent verification of the DBNPS program was considered. The closeout letter (dated November 29, 1999) was prepared by the NRR project manager using guidance issued in a memorandum from the Division of Engineering to the Division of Licensing Project Management (dated June 14, 1999). The memorandum provided form letters for project managers to use as the basis for the NRC responses. The closeout letter for DBNPS closely followed the format of the form letter. It refers to licensee responses to NRC requests for additional information, however, plant-specific information is not discussed in any detail. The closeout discusses generic submittals made by NUMARC and the B&WOG.

(6) The task group discovered a significant omission from the Davis Besse GL 97-01 closeout letter in that it does not address the issue of Intergranular Attack (IGA) that could result from resin intrusion into the reactor coolant system (RCS). IGA is discussed in the description of the Zorita event included in GL 97-01. DBNPS had a purification demineralizer failure resulting in a resin burst event during plant shutdown on April 10, 1998. Resin beads clogged the downstream filters and a loss of letdown occurred. As discussed in NRC inspection reports 98005 and 98007, operations activities caused some resin transport downstream of the filters. One report indicates that plant operators prevented resin intrusion into the RCS, but this was not substantiated in the report details section. As discussed in GL 97-01, resin intrusion into the RCS can cause IGA and cracking of A600 nozzles. Generic Letter 97-01 closeout should have addressed the DBNPS resin intrusion event and whether there was a potential for the Zorita phenomenon at DBNPS. Although IGA cracking of the head nozzles is no longer an issue, additional follow up should be performed to confirm that no resin intrusion in the RCS occurred, that the issue was appropriately evaluated by the licensee with respect to IGA of other Alloy-600 components, and whether IGA occurred in head nozzles before refueling outage 13.

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(7) The NRC Project Manager's Handbook, Section 2.4, includes guidance on responses to licensees concerning generic communications The Handbook discusses generic communications follow up to be conducted by the project manager:

> "there are some cases where the staff intentionally does not perform a detailed review in response to certain Bulletins, Generic Letters, etc. For these issues, the staff must ensure that the requested actions are adequately addressed by the licensee. The PM subsequently sends the licensee an acknowledgment letter, with a caveat stating that the licensee's response may be subject to future inspection or auditing In these cases, a large part of the staff's basis for the acknowledgment closeout letter is the future inspection of all plants (or a sample of plants)."

The closeout for Generic Letter 97-01 at DBNPS did not include the caveat regarding future NRC inspection or auditing.

(8) Similar information has been requested of licensees for several years with limited success. DBNPS had not planned on performing detailed inspection of the CRDM penetrations suggested in GL 97-01 until refueling outage 13 in 2002. For example:

(1) Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," requested licensees to provide information related to the integrity of the reactor coolant pressure boundary including the reactor pressure vessel head and the extent to which inspection have been undertaken, and the basis for concluding that plants satisfy applicable requirements, and that future inspections will ensure continued compliance with regulatory requirements.

* Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," requested licensees to provide information related to the structural integrity of the RPV head penetration nozzles including the extent of nozzle leakage and cracking that had been found , the inspections and repairs that had been undertaken, and the basis for concluding that their plans for future inspections will ensure compliance. A Temporary Instruction for regional inspections was written for this bulletin, but it failed to address boric acid issues.

* Generic Letter 97-01 requested licensees to provide a description of all inspections of CRDM nozzle and other vessel head penetrations performed to date, including the results of those inspections, and if a plan had been developed to periodically inspect the CRDM nozzles and other vessel head penetrations, licensees were to provide the inspection schedule and its technical basis. Licensees were to provide the scope for the CRDM and other vessel head penetrations, including the total number of penetrations, which penetrations had thermal sleeves, which were spares, and which were instrument or other penetrations. Licensees were also to provide a description of any resin bead intrusions.

(9) Information provided by DBNPS in response to Bulletin 2001-01 was not seriously questioned or challenged by the NRC prior to allowing continued operation until February 16, 2002. The information that was provided to the NRC was confusing and not

consistent. The following examples of paraphrased DBNPS statements that should have been questioned by the NRC to determine their technical basis:

<u>FirstEnergy Nuclear Operating Company (FENOC) letter to the NRC on September 4, 2001</u>

* Installed [RPV head] insulation does not impede a qualified visual inspection of the RPV head.

* Inspections of the RPV head were performed in accordance with DBNPS procedure NG-EN-00324, "Boric Acid Corrosion Control Program," which was developed in response to Generic Letter 88-05." However, procedure NG-EN-00324 requires that.

  The affected areas should be inspected to identify any signs of corrosion. This will most likely be exhibited by red rust or red/brown stained boron If corrosion is present, the amount of corrosion should be estimated. This should include an estimate of corrosion products present as well as an estimate of base metal removed... The affected components should be carefully inspected to determine if a boric acid solution is present or just crystals and residue If active leakage is present a leak rate should be measured or estimated and then action taken to stop the leakage... Identify insulation or any other type of interference which must be removed to gain access to the leak... Plant Engineering shall determine whether follow-up or more detailed inspections of the leak are necessary to fully assess component damage and determine possible corrective action. [If a detailed inspection is deemed necessary, then the procedure required] A detailed description of visible damage to the affected area. This description should include the presence of pitting or material wastage. If corrosion is present, then the depth of pitting or wastage should be identified. This information is required for the analysis of component integrity.

  In addition, PCAQR 96-0551 (Boric Acid on Reactor Vessel Head) initiated on April 21, 1996 indicated that "There could also be corrosion damage within the reactor vessel head penetration due to boric acid corrosion resulting from a through wall crack in the CRDM nozzle." The PCAQR also stated that procedure NG-EN-00324 (Boric Acid Corrosion Control) "... may not have been followed to identify the scope of problem."

* Some boric acid crystals had accumulated on the RPV head insulation beneath the leaking flanges. These deposits were cleaned. After cleaning, the area above the insulation was videotaped for future reference.

* Inspection of the RPV head/nozzles area indicated some accumulation of boric acid deposits. No evidence of nozzle leakage was detected.

* Review of 1998 and 2000 Inspection Videotapes of the RPV confirmed that the indications of boron leakage experienced at the DBNPS were not similar to the indications seen at Oconee Nuclear Station (ONS) and Arkansas Nuclear One Unit 1

(ANO-1), and that indications such as those that would result from R V. head penetration leakage were not evident.

* DBNPS performs visual inspections for evidence of leakage by examining the RPV head surface and the CRDM flanges per the requirements of NRC Generic Letter 88-05, and if pressure boundary leakage is suspected, supplemental examinations of the affected CRDM nozzle will be performed to characterize the integrity of the nozzle.

FENOC letter to the NRC on October 17, 2001

* Results from previous inspections of the CRDM nozzle penetrations provide reasonable assurance for the continued safe operation of the DBNPS until the next refueling outage in March 2002.

First FENOC letter to the NRC on October 30, 2001

* The inspections performed during the 10th, 11th, and 12th refueling outages consisted of whole head visual inspection of the RPV head in accordance with the DBNPS Boric Acid Corrosion Control Program pursuant to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR plants."

* Following 12RFO, the RPV head was cleaned with demineralized water to the extent possible to provide a clean head for evaluating future inspection results.

* During the 12RFO inspection, 24 of th4e 69 nozzles were obscured by boric acid crystal deposits that were clearly attributable to leaking motor tube flanges from the center CRDMs. A further subsequent review of the video tapes has been conducted and corroborates the previous statements and conclusions ... that the results of this review did not identify any boric acid crystal deposits that would have been attributed to leakage from the CRDM nozzle penetrations, but were indicative of CRDM flange leakage.

Second FENOC letter to the NRC on October 30, 2001

* A good video inspection was able to be performed for those 50 drives that were not obscured by boron from leaking CRDM flanges. Although much more video can be viewed, these attached pictures are representative of the condition of the drives and the heads. We attempted to capture in still photographs all of the outer most drives since they are the most susceptible to circumferential cracking based upon finite element analysis.

* These drives were video taped [RPV head inspection results from 12RFO] because they had boron deposits in the vicinity of the CRDMs. Completely clean drive penetrations are not depicted here.

The NRC responded to DBNPS' Bulletin 2001-01 correspondence on December 4, 2001 with the following statement: "Based on the information provided in your responses and the information available to the staff regarding the industry experience with vessel head penetration (VHP) nozzle cracking, the staff finds that you have provided sufficient information to justify operation until February 16, 2002, at which time you will shut down the DBNPS Nuclear power Station, Unit Nol 1, facility for the next refueling outage and perform VHP nozzle inspections as discussed in your letter dated November 30, 2001."

(10) NRR Office Instruction LIC-503, "Generic Communication Affecting Nuclear Reactor Licensees," does not require an assessment of generic communication implementation by licensees for bulletins, generic letters, or information notices. Follwoup of generic communication by use of a temporary instruction is optional for bulletins and generic letters. For higher level issues that are classified by the NRC as "generic issues," Management Directive 6.4, "Generic Issues Program," requires a closeout verification of licensee corrective action implementation and an assessment of the effectiveness of corrective actions.

(11) 1991 NRC action plan status was inconclusive. Generic Letter 97-01 references a 1991 NRC action plan to address PWSCC of Inconel 600 components. The action plan is documented in a memo from Richardson to Russell (dated December 12, 1991), and it specifies seven future activities. The task group attempted to determine what followup the NRC conducted on the action plan activities. In memoranda related to staff activities in this area (March 24, 1992, memo from Wiggins to Richardson and November 30, 1993, Taylor to Commission), the staff did not clearly indicate the disposition of the seven activities.

(12) NUREG/CR-5576, "Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Plants," issued in 1990, provides 17 events involving boric acid corrosion wastage are given which include valve parts, fasteners, nozzles, including two examples of RPV head wastage are provided in. Bulletin 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion," including its two supplements, provide examples of valve component wastage and RPV head wastage. Since IN 86-108 required no information or actions be taken by licensees, its effectiveness is questionable. Little operational experience presented in the IN was included in DBNPS Boric Acid Corrosion Control Program until their program revision in May 2002. Had the NRC required licensee action, and monitored actions being taken, the number and severity of subsequent boric acid leakage and corrosion events may have been reduced. Neither of the two events involving RPV head corrosion (caused by primary system leakage and boric acid buildup), were documented in LERs.

(13) Previous guidance provided in generic communications may not be accurate concerning boric acid corrosion rates. The NRC position on primary system leakage and subsequent boric acid corrosion indicates a reliance on licensee actions to curtail leakage, and an overall assessment that RPV head corrosion would be slow to develop, recognizable, and not an immediate safety concern. Paraphrasing statements made in Bulletin 2002-01, boric acid deposits on the RPV head were assumed to cause minimal corrosion while the reactor was operating because the temperature of the RPV head would be above 500 F, and that dry boric acid crystals were not very corrosive. Therefore, wastage was typically expected to occur only during outages when the boric acid could be in solution, such as when the temperature of the RPV head falls below 212 degrees F. However, the findings at DBNPS bring into question the reliability of this model. The NRC model guidance is also not consistent with head wastage events contained in IN 86-108, or with foreign experience.

(14) Bulletin 2002-01 states "Inspections performed to date at plants with high and moderate susceptibility have generally confirmed the ability of the model to predict a plant's relative susceptibilities; however, a plant with a ranking of 14.3 effective full-power years from the Oconee 3 condition (at the time when circumferential cracking was identified at Oconee 3 in March 2001) identified three nozzles with cracking; other plants with fewer effective full-power years from the Oconee 3 condition did not identify cracking." This information would also question the statistical uncertainties associated with this model.

(15) The NRC does not inspect licensee implementation of owners group correspondence that contains performance requirements. Nor does the NRC inspection program include verification of owners group submittal assumptions. This is particularly important where the NRC has accepted a group industry response rather than a plant specific response.

Recommendations:

[10] Consider the need to verify that corrective actions have been implemented to address past significant generic communications and generic issues.

[11] Consider establishing a process for verification of licensee and agency actions to address generic communications. Consider also the need to verify the effectiveness of licensee and agency corrective actions to address generic communication.

[30] Assess the overall scope and process for reviewing operational experience

[16, 12] Consider the need to consolidate the generic communication program (LIC-503) and the generic issues program (MD 6.4)

[24] Consider establishing criteria for accepting "industry" resolutions for generic communications and generic issues.

3.1.4 Generic Issues Program Implementation Weaknesses

The Generic Issues Program did not specifically address nozzle cracking, boric acid leakage, or boric acid corrosion. NRC studies were performed in these areas, but they were not escalated to the point of being a candidate generic issue. However, there was one generic safety issue that did involve boric acid corrosion

(1) Boric acid corrosion events were not considered as a candidate generic issue. However, Generic Safety Issue 29, "Bolting Degradation or Failure in Nuclear Power Plants," was initially proposed because of a boric acid corrosion event at Fort Calhoun in 1980. During a surveillance test, it was discovered that significant corrosion damage had occurred involving several of the pump casing to pump cover studs on all three reactor coolant pumps. This issue was later expanded to include bolting failures of primary pressure boundary components and included other initiators such as stress corrosion, fatigue, and erosion corrosion. NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants, " issued in June 1990, provided the basis for resolution of Issue 29. This issue was classified as "resolved" in 1991.

(2) Many programmatic and staffing changes have occurred over time in processing

candidate generic issues The Commission originally requested that generic issues be reviewed and tracked in late 1976. Subsequently, a generic issues program was published in 1978. Following the accident at Three Mile Island 2, many generic issues arose, and NRR was given the program responsibility for generic issues. Following an NRC reorganization in 1987, RES was assigned the program responsibility within the Division of Safety Issue Resolution (DSIR). With the elimination of DSIR in 1994, the generic issue program function was transferred to the Generic Safety Issues Branch in RES. Recently, in 1999, the Generic Issues Program was transferred to a team of 4 engineers with the Regulatory Effectiveness Assessment and Human Factors Branch within RES. The NRC staffing and contract money to review, assess, and closeout candidate generic issues has significantly dropped. The Generic Issues Program is the primary process for addressing a regulatory matter involving the design, construction, operation, or decommissioning of several or a class of , NRC licensees that is sufficiently addressed by existing rules guidance or programs. NRC Management Directive 6.4 "Generic Issues Program" is the agency procedure governing this process and it is managed by the Office of Research. Candidate generic issues can be proposed by the public, industry, or the NRC. Once proposed, candidate issues are evaluated for risk significance, and if certain thresholds are met, detailed analysis may be performed. Following an analysis, recommendations are made which may include both industry and NRC actions.

(3) The number of candidate generic issues has significantly dropped off over the last few years. Interviews with NRC staff members conducted by the task group indicated that approximately 80 percent of the issues have been developed from issues in NRR user needs requests. The Generic Issues Program tracking began in 1983. New generic issues ere identified in the range of 19 to 56 per year between 1983 and 1991, except for three years when the rate was less than 10. This trend significantly change between 1992 to 2001 when new generic issues averaged 3.4 per year. A cumulative total of 834 candidate issues were identified by 1995. During the period 1996 to 2001, interviewees indicated that there was a strong focus on addressing the excessive backlog of generic issues and not identifying new generic issues. As a result, the backlog was eliminated and only 10 new issues were addressed. Currently (2002) there are 10 generic issues to be dispositioned.

(4) The Generic Issue Process is perceived to be cumbersome and time consuming. Due to the perceived involved nature of generic issue recognition, initial characterization, analysis, and the time required for closure, few candidate generic issues have been proposed over the last few years. NRR as the lead NRC office, would prefer to quickly act on an emerging issue through the issuance of INs, Bulletins, or Generic Letters (listed in order of preference) with the expectation of early closeout, rather than submitting an issue as a candidate generic issue in accordance with MD 6.4, that may take a year or more to analyze and longer to effectively closeout by verification inspections.

<u>Recommendations</u>:

[*] Establish a central operating experience screening group to identify issues for Generic Issues Program based on US and foreign experience

[&] Evaluate/revise guidance for proposed generic communications.

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[*] Determine if screening criteria for candidate generic issues are acceptable.

[*] Assess consolidation of generic communications process and the Generic Issue Program (GIP).

[*] Ensure that generic requirements or guidance are not eliminated or undermined when making changes to regulatory processes (e.g., deleting inspection procedures).

[*] Update MD 8.5, MD 6.4, and NRR Office Instruction LIC 503, "Generic Communications Affecting Nuclear Reactor Licensees "

[*] Enhance criteria for Boric Acid Corrosion Control (BACC) programs.

3.1.5 Operating Experience at Foreign Nuclear Power Plants Was Not Utilized

The operating experience from foreign countries were evaluated and dispositioned as not applicable to the U.S. plants. When the Oconee circumferential cracking was observed in February 2001, the lessons from the foreign experiences were not factored into the decision making process.

(1) An internal NRC trip report dated November 15, 1991 documented the NRC knowledge of VHP nozzle cracks at the French Nuclear Station, Bugey unit 3. In addition, NUREG/CR-6245, issued in 1994, documents the inspection of 4181 VHP nozzles at 67 overseas plants that identified 101 penetrations with indications.

(2) NUREG/CR-6245 included the inspection of one US plant, Point Beach unit 1. No crack indications were identified. The lack of any indications was attributed to the differences in fabrication process. The Point Beach VHP nozzles were fabricated from tube material and heat treated at 1725 degrees F. The penetrations for the French plants were forged bars and heat treated at 1508 degrees with yield strength greater than 49.7ksi. The Point Beach nozzle material was likely to have had a lower yield strength, lower residual stresses, larger grain size, and less susceptible micro structure than Bugey unit 3. The Point Beach station had 23 years operation and no crack indication while the Bugey unit 3 had a through wall crack after 10 years of operation. The NUREG conclusions mentioned the possibility of circumferential crack propagation and rod ejection but was not considered a possibility within the current licensing period. The axial cracks were considered not to grow through-wall because of the comprehensive axial stress present. A conservative time for the hypothetical through-wall crack was estimated to be six years. The conclusions recognized the use of nitrogen-13 leak monitoring system capable of detecting 0.001 gallons per minute (gpm) from the RCS.

(3) On November 19, 1993, in response to the pressurized water reactor (PWR) owners Group submittals integrated by Nuclear Management and Resource Council (NUMARC), NRR issued a safety evaluation report (SER) concluding that there was no immediate safety concern for cracking of VHP nozzles. The SER noted that NUMARC submittal did not address the Bugey unit 3 flaw, that was oriented at 30 degrees off the vertical axis or a circumferential flaw at Ringhals and indicated the need for a later assessment on these flaws.

(4) While NRC conclusions alleviated immediate safety concerns on the basis that the cracks would noticeably leak prior to flaw size reaching unstable dimensions, the French regulatory agency proceeded with an aggressive VHP nozzle inspection program, capability to detect small reactor coolant leaks, design of a device to prevent rod ejection, and minor reactor internal modifications to reduce the under-head temperature. The details of the French experience in this area was published in the Proceedings of International Symposium on Pant Aging and Life Predictions of Corrodible Structures on May 15-18, 1995 under the title Status of Alloy 600 Components Degradation By [primary water stress corrosion cracking] PWSCC in France: Incentives and Limitations of Life Predictions as Viewed by a Nuclear Safety Body.

(5) The French experience further concluded that crack susceptibility modeling had significant limitations that make it impractical to perform any credible prediction. Some of the influencing factors are namely 1) The incapability to know the bulk residual stresses and the values are often estimated to the elastic limit of the semi-manufactured product, 2) Unknown stresses introduced through final finishing like straightening, reaming, machining, cold working etc., that are not sufficiently documented, 3) Influence of dimensional changes and deformation in relation to the initial conditions, 4) Disproportionate coupling to time and temperature based on the vessel cracks experienced at Blayais at an estimated temperature of 289 degrees C. 5) Difficulty in measuring the actual internal wall temperature, 6) The susceptibility difference between heat to heat and batch to batch due to variations in thermo-mechanical processes and carbon content, and 7) Intrinsic scatter of time to primary water stress corrosion cracking (PWSCC) initiation exhibited by identical specimens of Alloy 6000.

(6) Crack initiation was found in new pants like Cattenom unit 2 after an operating time of 36,000 hours while Fessenheim unit 2 did not have any cracking after 107,000 hours of operation. Based on these factors, the French predictive model that was revised several times, subsequently concluded that modeling is impractical, if not misleading to prioritize inspections or maintenance. The regulators required in principle, an avoidance of a through wall longitudinal crack in the next fuel cycle. Therefore, the inspection program required an eddy current inspection even in the absence of any indication. Reactor pressure vessel head visual inspections with the insulation removed was required in every outage from the early 1990s. When indications were observed, eddy current and ultrasonic test (UT) inspections were required more frequently. The RPV head replacement became an economical decision by the utilities when considering the increased frequency of volumetric examinations that were required when indications were discovered.

(7) Knowledge and experience has a direct relation to recognizing problems. In spite of the discovery of circumferential cracking identified VHP nozzles at Oconee unit 3 in February 2001, and two circumferential cracks at Oconee Unit 3 in April 2001, NRR continued to accept visual examinations that did not require the removal of the insulation or a thorough cleaning of the RPV head region for collecting any trend information. When VHP nozzle cracking was discovered at Oconee, foreign experience in VHP nozzle circumferential cracking was not explored. The Oconee VHP nozzle circumferential crack, and VHP cracks at 4 different foreign countries were known to NRC management. The French VHP inspection program was shared with several NRC managers. However, foreign experience was not shared with the technical staff.

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3.1.6 Technical Positions on Boric Acid Leakage Underestimated Potential Consequences

(1) In 1993, the NRC stated its reliance on visual inspections as the best method for detecting leaking nozzles, and that inspections at fixed intervals, based on experimental evidence, are also cited as bases for safety assurance. The NRC also indicated that RPV head penetration non-destructive examination (NDE) inspections should be done, but cited worker exposure concerns as basis for not requiring such inspections An NRC Safety Evaluation on VHP nozzle cracking concluded that a flaw would be detected during plant walkdowns, instituted as a result of implementation of Generic Letter 88-05 for boric acid leakage. NRC Safety Evaluation recommended enhanced leakage detection by visually examining the reactor head until either inspections showed no cracks existed, or that on-line leak detection be installed in the head area

(2) The NRC reviewed PWR owners group submittals that provided their safety assessments of RPV head penetration cracking, including the assessment conducted by the Babcock and Wilcox Owners Group (B&WOG). The basis of the B&WOG safety evaluation regarding identification of nozzle leak corrosion-induced wastage was dependent upon VHP flange leakage being identified and corrected each outage, which would include any needed head cleaning. In addition, DBNPS did not have a tracking mechanism to ensure that the requirements or assumptions of the B&WOG Safety Evaluation and the NRC Safety Evaluation were incorporated into station licensing commitments or station procedures

(3) The 1993 NRC Safety Evaluation on NUMARC's submittal for each of the PWR owners groups includes the following similar statements:

> ...catastrophic failure of a penetration is extremely unlikely. Rather, a flaw would leak before it reached the critical flaw size and would be detected during periodic surveillance walkdowns for boric acid leakage pursuant to Generic Letter 88-05. However, the staff recommends enhanced leakage detection by visually examining the reactor vessel head until either inspections have been completed showing absence of cracking or on-line leakage detection is installed in the head area.
>
> B&WOG estimates 10 years from the time a flaw initiates on the inside diameter of a VHP nozzle until a leak appears. Once a leak starts, B&WOG concluded it would take 6 years before enough corrosion would occur to reduce wall thickness of the reactor vessel head to below ASME code minimums, and that this amount of leakage would be detected during surveillance walkdowns.
>
> Staff concluded PWSCC does not create an immediate safety issue as long as any leakage is corrected.
>
> Leakage at less than 1 gpm would be detectable over time based on boric acid buildup as noted during periodic surveillance walkdowns. Although NUMARC has proposed, and the staff agrees, that low level leakage will not cause a significant safety issue to result, the staff

> determined that NUMARC should consider methods for detecting smaller leaks to provide defense-in-depth to account for any potential uncertainty in its analysis ... The staff notes that small leaks resulting from flaws which progressed through-wall just prior to a refueling outage would be difficult to detect while the thermal insulation is installed. Although running for an additional cycle with the undetected leak would not result in a significant safety issue, the NUMARC should consider proposing a method for detecting leaks that are significantly less than 1.0 gpm, such as the installation of on-line monitoring equipment.

3.1.7 NRC Review of Industry Guidance to Licensees

The NRC did not review the Electric Power Research Institute (EPRI) guidance containing RCS leakage detection techniques. This same guidance was not incorporated in DBNPS' BACC Program. In April 1995, EPRI published Boric Acid Corrosion Guidebook to help the industry to implement an effective Boric Acid Control Program. Under methods to detect leak rates less than about 0.1 gpm (Section 6.2.2 of the Guidebook) two specific guidelines were given, (1) Containment air cooler thermal performance as observed in coil heat transfer degradation, and (2) consideration for monitoring the boric acid concentration in the containment air cooler condensate. Under other potential indicators, there was reference made to observing high containment particulate reading Each of these component areas mentioned in the EPRI Guidebook was a source of chronic concern at DBNPS, along with many other boric acid leakage indicators, and were also known by NRC staff and managers, but were not adequately assessed and corrected in a timely manner.

3.2 The Licensee Did Not Assure That Plant Safety Issues Received the Appropriate Attention

In order to assess NRC's regulatory processes relative to the DBNPS event, the task force had to gain a fundamental understanding of DBNPS's performance. In doing so, the task conducted independent review activities, as well as considered the information developed by the NRC's AIT and the licensee's various root cause analyses effort. The task force concluded that licensee did not foster an environment that was fully effective in assuring that plant safety issues received the appropriate attention Additionally, the task force concluded that the lack of timely identification of VHP nozzle leaks and the boric acid corrosion wastage was directly attributed to plant's safety environment that was developed at DBNPS. The bases for these conclusions is documented in the following discussion, as well as other sections of this report. Additionally, much of the information identified by the task force was provided to a number of other NRC organizations in support of on-going review activities

The task force identified numerous performance lapses, in multiple areas, that were indicative of an inadequate safety focus. These included: 1) engineering resources that were stretched thin by budget and staffing cuts; 2) an imbalance between production focus and safety focus as evidenced by taking symptomatic actions that did not impede power operations while not implementing rigorous and thorough corrective actions during outages because of budget and scheduler concerns; 3) a lack of management involvement in important safety significant work activities and decisions ; 4) a lack of a questioning attitude by senior managers; 5) a lack of engineering rigor in the approach to problem resolution; 6) a long-standing acceptance of degraded equipment, particularly RCS components; 7) a lack of training and inability to effectively internalize lessons-learned from past similar events; 8) the inability to recognize or address repetitive or recurring problems; 9) ineffective and untimely corrective actions, particularly for issues that are costly to resolve; 10) untimely and cursory review of industry operating experience, both internal and external; 11) the cancellation or deferral of safety-related work simply on the basis of budgetary or scheduler considerations; 12) the existence of uncorrected inaccurate or incomplete written information provided internally and externally; 13) ineffective self-assessments of safety performance; 14) a lack of ownership of plant problems; 15) a lack of compliance with plant procedures; 16) a lack of rigor in conducting safety-related work activities; 17) and other indications of an unhealthy safety conscious work environment.

3.2.1 The Licensee Did Not Adequately Address Long-Standing Reactor Coolant System (RCS) Leaks

The licensee did not adequately address numerous long-standing RCS leaks, in general, and the VHP nozzle leaks, in particular. The plant experienced numerous leaks of CRDM flanges, as well as RCS valves and other components. The licensee tolerated these leaks, often, starting up the plant from refueling outages without having located all the leaks or having repaired all the ones that were known. This chronic acceptance of leaks was noted in third party assessment of the plant's performance. This acceptance is all the more troubling given two past precursor events. The licensee expended considerable effort in addressing the symptoms of active RCS leaks, such as power washing the containment air coolers, changing the filter elements of the containment radiation monitors, changing the radiation monitor sample points, bypassing the iodine filter cartridge, and installing portable HEPA filters inside containment. None of these activities affected power operations even though the licensee may have violated the Technical Specifications for the radiation monitors in the 1998 and 1999 time frame. Additionally, the licensee expended a significant amount of the operating cycle 13 radiation dose budget on these symptomatic activities. It did not appear that the licensee's pre-outage intentions to perform a thorough and rigorous containment walk-down to identify the source of the leaks was implemented in the spring 2000 refueling outage.

3.2.1.1 Detailed Discussion

Reactor coolant system leakage at DBNPS was historically low and rarely greater than 20 percent of the 1 gpm Technical Specification limit for unidentified non-RCPB leakage. One exception was the period from October 1998 to May 1999, when a modification to the pressurizer relief valve discharge piping was installed that resulted in unquantified pressurizer safety valve seat leakage to be released to the containment atmosphere. Several small non-RCPB leaks had occurred during the 1990s that the task group concluded contributed to an acceptance on the part of the licensee that RCS leaks were a normal condition of operation. Since RCPB leakage is indistinguishable from non-pressure boundary leakage without inspection, failure to adequately address and eliminate small non-RCPB leakage conditioned the staff to assume that leakage was not from the RCPB.

As symptoms of RCS leakage became more prevalent from 1998 to 2002, equipment required to be operable by the Technical Specifications was affected. This equipment included the containment air coolers (CACs) and portions of the RCS leakage detection system (gaseous and particulate radiation monitors). Operability of these systems was required for continued plant operation. As the performance of these systems became degraded or inoperable, conditions were corrected to restore system performance and prevent a Technical Specification-required plant shutdown, but the cause of the condition (RCS leakage) was not corrected. Neither was it determined whether RCPB leakage was present.

Some examples of RCS leakage sources included the following·

- <u>Reactor Vessel Head Vent Leakage</u>

  The Davis-Besse reactor vessel head vent design consisted of a hard pipe connecting the reactor vessel head to the No. 2 steam generator and was first installed in the 1988 refueling outage (RFO 05). The head vent pipe has a bolted, flanged connection at the reactor vessel head and the steam generator and is required to be removed from the reactor vessel head during each refueling outage to allow removal of the reactor vessel head.

  During the 1990 refueling outage (RFO 06), leakage and corrosion was identified at the steam generator connection and documented in PCAQR 90-0051. The gasket was replaced and the joint did not exhibit any leakage during the next operating cycle.

  In February 1992, the licensee began to investigate elevated RCS leakage and during a brief plant shutdown on March 1, 1992, identified that the connection at the No. 2 steam generator was leaking. The licensee and NRC senior resident inspector noted that the CAC coils were also coated with boric acid. The task group interviewed the NRC resident inspector at the time, who recalled that the CAC coils were easily cleaned with demineralized water. The licensee evaluated the boric acid fouling condition of the CACs in PCAQ 92-0072, concluding that they were still capable of performing their post-accident containment cooling function. The task group concluded that the licensee's engineering evaluation conclusion that post-accident air flow and would clear boric acid buildup from the CAC coils lacked rigor. The licensee continued to operate with the leaking head vent connection until the following refueling outage in March 1993 (RFO 08). The licensee initiated PCAQ 93-0098 to document evaluation of the condition and implemented Modification 92-0004, "Repair of Reactor Head Vent Line," during the outage to improve the joint design. The modification was inspected during an NRC modifications inspection documented in NRC Inspection Report 50-346/92018. The NRC resident inspector recalled from the inspection that there was 1 1/8-inch wastage of base metal due to the leak that had to be repaired The BAC program was not assessed as part of this review.

- RCS Instrumentation Nozzle Leakage

Several examples were noted during the task group's review of cases of RCS hot and cold leg instrumentation leaks The RCS resistance temperature detector (RTD) thermowell leakage boundaries consisted of two types: 1) a gasket between the thermowell and thermowell boss compressed by the thermowell nut, and, 2) a threaded and seal welded thermowell joint. Both joint types had historically leaked during operation and required repair during outages. Both are the subject of a restart project modification to prevent future leakage.

- Control Rod Drive Mechanism (CRDM) Flange Leakage

The Babcock and Wilcox CRDM design contains a bolted flanged connection to the reactor vessel head nozzles. This connection had been known to leak and had been documented in correspondence with the NRC staff. For example, in 1989 Arkansas Nuclear One (ANO) - Unit 1 identified significant degradation of a CRDM flange assembly from boric acid corrosion and reported this to the NRC in Licensee Event Report 50-313/89-043. Corrective actions at ANO included replacing the CRDM nozzle flange gaskets with an improved design over a three-cycle replacement campaign. No additional leaking CRDM flanges had been identified at ANO following the 1989 event. Davis-Besse similarly replaced CRDM nozzle flanges over a four-cycle replacement campaign but had continued to identify leaking CRDM flanges through the 2000 refueling outage (RFO 12).

The Babcock and Wilcox Owners Group acknowledged to the NRC staff that CRDM flange leaks were a known problem. In its June 6, 1993, submittal to the NRC staff on the subject of potential CRDM nozzle cracking, NUMARC forwarded copies of safety evaluations from each of the PWR owners groups evaluating the subject. The Babcock and Wilcox Owners Group safety evaluation stated that: "Leakage of B&W-design flanges has been previously experienced, and visual inspections of the RV head area have been implemented so that flange leaks can be identified and repaired as soon as possible." And, "At each of the B&WOG utilities plant's, a walkdown inspection of the RV head has been implemented in response to NRC Generic Letter 88-05. As mentioned earlier, CRDM gaskets have been known to leak; thus, the walkdown inspection includes visual inspection of the gasket area during every refueling outage (12-24 months)." The maintenance history of Davis-Besse CRDM flanges was described in the NRC's Augmented Inspection Team report of the Davis-Besse event. The task group concluded that the ongoing nature of CRDM flange leaks at Davis-Besse helped condition the licensee to expect that any RCS leakage in the head area was from CRDM flanges. The tolerance for the accumulation of boric acid on the head from these leaks prevented the capability to perform an inspection to confirm that no RCPB leak existed

During Refueling Outage (RFO) 12, which was conducted in the spring of 2000, Condition Report 00-1037 was initiated to document that boric acid accumulation was identified on the reactor vessel head and on top of the thermal insulation beneath the CRDM flanges. As part of the response to the condition report, the RCS system engineer evaluated the boric acid deposits on the head and if the source was from CRDM flange leakage. There were 5 CRDM flanges that were initially identified as having possible leaks. Four of the flanges had positive signs of leakage; however, for flange G9 the engineer stated, "Since the boron is evident only under the flange and not on the vertical surfaces, there is a high probability that G9 is a leaking CRD". CRDM flange G9 corresponds to CRDM Nozzle 3 which had through-wall cracks identified in RFO 13.

There was no apparent follow-up to the high probability of the leaking CRDM nozzle during RFO 12 or any other time.

In an interview with the task group, the system engineer stated that he never meant nor intended to imply there was a question of CRDM nozzle cracking. He said that if they had ever had an indication that nozzle cracking had occurred then everyone would have recognized the significance of the situation and would have properly deposited the item. However, the system engineer could not provide a reasonable explanation of the specific wording in the condition report regarding *"there is a high probability that G9 is a leaking CRD"* and how this wording could mean something other than the obvious meaning that there was RCPB leakage.

- Leakage of Pressurizer Spray Valve RC-2

As described in NRC Inspection Report 50-346/98021, during the 1998 refueling outage (RFO 11), pressurizer spray valve RC-2 was found to have packing leakage which caused significant boric acid corrosion of the valve yoke. Upon plant startup, packing leakage resumed and was evaluated as acceptable. Repetitive containment entries were made to monitor the leak. Although the plant had been shutdown in June 1998 following a tornado event and twice in July for steam generator cleaning, the licensee did not repair the leak, other than to install a Furmanite leak sealant injection rig on July 24. During subsequent containment entries body-to-bonnet nuts were missing. During an unplanned shutdown in October 1998, some body-to-bonnet studs and nuts were found to have been installed with the incorrect material. This licensee reported this event to the NRC in Licensee Event Report 50-346/98009 and it resulted in the issuance of a Severity Level III violation on August 6, 1999.

- Leakage of Letdown Cooler Isolation Valve MU-1A

As described in NRC Inspection Report 50-346/98018, the licensee identified that letdown cooler 1-1 isolation valve MU-1A had a packing leak while trying to identify sources of RCS leakage in December 1998. The licensee's plans to address the leakage were limited to the packing leak. NRC inspector prompting was required for the licensee to investigate whether body-to-bonnet stud conditions similar to that experienced with pressurizer spray valve RC-2 existed. When insulation was removed, a body-to-bonnet leak 270 degrees around the sealing surface was identified. The licensee then took actions to minimize the leakage. The fastener materials for this valve were found to be correct and there was no boric acid corrosion of the valve components The task group concluded that the licensee's initial plans to investigate and correct this source of RCS leakage were poor. They were minimal in scope to assess the extent of condition, given the recent experiences obtained with Valve RC-2.

- Leakage from Pressurizer Relief Valve Discharge Piping

  In 1997, engineering personnel documented in Potential Condition Adverse to Quality (PCAQ) Report 97-1518, a potential concern that pressurizer relief valve nozzles could be overstressed if only a single rupture disk were to burst. Each relief valve had two rupture disks in its discharge pipe which would discharge to containment atmosphere if the safety valve lifted A drain line between each relief valve and its set of rupture disks transported relief valve seat leakage to the quench tank. To address this concern on an interim basis, Temporary Modification 98-0036 was installed during an outage in October 1998. The temporary modification consisted of cutting open the rupture disks and severing the drain lines. This would prevent the hypothesized eccentric nozzle loading and overstress condition.

  Prior to installation of the modification, any relief valve seat leakage would be counted as "identified" RCS leakage, because it was directed to the quench tank and accounted for in RCS inventory balance calculations. With the modifications installed, any seat leakage would discharge directly to the containment atmosphere and the resulting RCS inventory loss would be "unidentified" RCS leakage. The task group reviewed the safety evaluation for the temporary modification package, which stated that, "Any safety valve leakage will be fluid from the pressurizer steam space. The leakage will result in a dispersion of dry boric acid crystals to the containment atmosphere with the potential for a lesser amount of liquid dripping on the mirror insulation on top of the pressurizer that would evaporate and result in a dry residual of boric acid on the mirror insulation. These conditions do not pose an increased risk for boric acid corrosion for any carbon steel components; i.e., the pressurizer head." The task group concluded that the technical justification provided for why boric acid corrosion of nearby components was not a concern was weak. Generic Letter 88-05 described an example of reactor coolant leakage finding a flow path to the inside of piping insulation, collecting there in contact with the carbon steel, and causing corrosion-induced wastage. Additionally, other potential places of boric acid accumulation, nearby valve components for example, were not addressed

During several task group interviews with plant staff, the pressurizer relief valve modification was cited the most plausible source of RCS leakage that was considered the cause for CAC fouling and RCS leakage detection system radiation monitor filter fouling in 1998-1999. The task group concluded that it was reasonable to assume that the relief valve seat leakage to containment was a contributor to increasing unidentified RCS leakage, however, as discussed in Section 3.3.1.1, the boron concentration in this contributor to RCS leakage (pressurizer steam space) may have been significantly less than the nominal RCS boron concentration and may not have been the significant contributor it was assumed to be for CAC and radiation monitor filter fouling. Nevertheless, it was an example the licensee's tolerance for RCS leakage in containment.

The temporary modification was removed during the May 1999 midcycle outage after further engineering analysis concluded that the eccentric loading concern was not substantiated.

The task group reviewed licensee activities to identify sources of RCS leakage in containment. Radiation work permit records indicate that online containment inspections were performed to identify leakage sources in 2000 and 2001. No specific radiation work permit for RCS leakage identification activities was initiated in 1999. The task group reviewed the procedure used when performing containment entries. Procedure DB-OP-01101, Containment Entry, Revision 00, step 6.2.7, states, "Proceed with entry assuring the group remains together at all times paying close attention to varying dose rates and other abnormalities such as; water on floor, steam leaks, excessive valve packing or pump seal leaks, unusual or high radiation dose rates, noise, etc." The task group noted that the procedure did not specifically identify boric acid identification which would enhance sensitivity to boric acid on components during containment entries.

The task group reviewed impact of RCS leakage on other technical specification-required systems. The principal items of focus were the CACs and RCS leakage detection system radiation monitors. However, other equipment in containment was affected by RCS leakage and requires additional assessment by the licensee and NRC prior to plant restart. Examples include consideration of the effects of boric acid on electrical cables, other piping inside containment, and the containment liner.

<u>RCS Leakage Detection Systems</u>

The Davis-Besse Safety Analysis Report Section 5.2.4, "Reactor Coolant Pressure Boundary Leak Detection System," identified that the RCS leakage detection system include the containment atmosphere particulate radioactivity monitoring system, the containment sump level/flow monitoring system, and the containment atmosphere gaseous radioactivity monitoring system. The systems are designed to meet the regulatory positions of NRC Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973. Technical Specification 3.4.6.1 identifies the limiting condition for operation of these systems. The bases for these systems is to provide means to detect and monitor leakage from the RCPB. The technical specifications also prohibit operation with any RCPB leakage, and an immediate plant shutdown is required if any RCPB leakage is identified.

Technical Specifications affecting RCS leakage detection systems were amended twice during the 1990s. License Amendment No. 180 was issued on September 9, 1993, and allowed use of the containment gaseous rad monitoring systems as an alternative means of detecting RCS leakage. License Amendment No. 234 was issued on November 16, 1999, and relaxed the requirement for the number of operable leakage detection systems and removed an immediate shutdown action requirement unless all three RCS leakage detection systems were inoperable.

The License Amendment Request (LAR) for Amendment No. 234 was submitted for NRC staff approval on July 26, 1999. The task group noted that this submittal correlated in time to shortly after an increase in frequency of RCS leakage detection system radiation monitor filters began. The LAR contained no information to imply that there was a material condition problem with the containment air radiation monitors. Rather, the LAR was part of a larger request to move some Technical Specification-required systems to the Technical Requirements Manual (TRM) and for the RCS leakage detection system technical specification system to reflect the Babcock and

Wilcox Improved Technical Specifications (ITS). The LAR was a straightforward request to implement NRC guidance for removal of systems from the technical specifications to the TRM or implementation of line-item TS improvements to match the Babcock and Wilcox ITS. Minimal NRR technical review was required

During the review period prior to issuance of Amendment No 234, iron oxide was also found on radiation monitor filters and HEPA filters were installed in containment to filter the containment atrmosphere. From interviews with licensee and NRC personnel, the task force determined that the RCS leakage detection system problems were not considered during NRC staff review of the LAR.

Issuance of Amendment No. 234 had the benefit to the licensee of eliminating the previous 6-hour shutdown action statement entry requirement if one train of radiation monitors (gaseous and particulate) became inoperable due to filter fouling while the other train of gaseous and particulate radiation monitors was out-of-service for any reason. This had occurred on at least two occasions prior to issuance of Amendment No. 234.

The task group reviewed performance of the RCS leakage detection system and noted that each train of radioactivity detector RCS leakage monitors became inoperable many times (hundreds) because of low air flow or saturated detector conditions from 1998 to 2002. The task group concluded that the radiation monitor RCS leakage detection systems had lost their usefulness by the licensee for meeting their design function, i.e., RCPB leakage detection.

The task group noted from review of control room logs that on some occasions, the radiation monitor RCS leakage detection system sample points were changed from their "normal" sample collection points (top of the D-rings) to their "alternate" sample collection points (containment dome and personnel hatch). This reduced the frequency of required filter changeouts but appeared to the task group to reduce the effectiveness of the monitoring systems from performing their design function.

Some condition reports the task group considered noteworthy were: Condition Report 1999-1300, which identified the accumulation of iron oxide on filters. Its corrective actions included the temporary installation of the HEPA filters inside containment (which the task group concluded only addressed the symptoms of the condition) and the plan to perform an RCS walkdown during RFO 12 to look for leaks. Condition Report 2001-1110 which requested a sample point change and Condition Report 2001-1822 written about the high frequency of filter changeouts and that boric acid was present. It stated, "Currently we still have a small RCS leak in containment. This is indicated by the boron deposits on the clogged filters. Our plan is to repair the small RCS leak during the upcoming refueling outage thus eliminate the necessity of frequent filter changes. Currently the criteria for filter change is either low flow alarm of 1.5 scfm or detector to go into saturation. ... chemistry satisfied with current replacement frequency (2-7 days). Plant engineering does not recommend any additional compensatory measures." None of the above condition reports addressed the possibility that the RCS leakage detection system was actually detecting an RCPB leak.

Each radioactivity detector RCS leakage detection system train also included a radioactive iodine monitor. This monitor was not required by the technical specifications and was not discussed in the Safety Analysis Report or other licensing basis document. However, this monitor was most prone to filter fouling and removing it from service for maintenance required removing the technical specification monitors of that train at the same time. The licensee installed Temporary Alterations 01-0018 and 01-0019 to eliminate the iodine monitor from the system on November 2, 2001. The task group concluded that removal of this monitoring system, although it was not required, was another example of the licensee tolerating RCS leakage without adequate assessment of its source.

Containment Air Coolers

The CACs provide both normal and post-accident heat removal from the reactor building. There are three units, (two independently powered and cooled trains and a "swing" unit). The CACs share a common discharge plenum. Each CAC has an inlet temperature instrument. The average of the inlet temperature of the operating CACs is required by Technical Specification 3.6.1.5 to not exceed 120 degrees F. There is a pressure instrument in the inlet plenum which provides an indication of the differential pressure across the CAC coils A decreasing value was an indication that CAC coils were becoming fouled and their heat transfer capability was reduced. As discussed previously, CAC fouling with boric acid had been recognized as a symptom of RCS leakage in 1992 when the reactor vessel head vent joint was found leaking. No additional cases of CAC fouling were identified until 1997. During review of station log entries, the task group identified that on May 22, 1997, during the main transformer forced outage, personnel on tour in containment noted boric acid buildup on the inside of the incore instrumentation tank and on CAC No. 2. The task group was unable to determine what, if any, corrective actions were taken in response to this condition. Additionally, an Ombudsman file indicated that a worker was concerned about boric acid particulate in one of the CACs in which he was performing work during the spring 1998 refueling outage (RFO 11).

The next documented case of CAC fouling the task group found was when the licensee initiated PCAQ 98-1980 on November 12, 1998. The licensee had observed that indicated CAC plenum pressure had been decreasing from 3" w.g. in early September to 2.0" w.g. on November 12. Operations documented that the condition was reviewed with the system engineer and that the CACs remained operable. A reactor building entry was made on November 14 for further inspection and it was observed that a thin, loose powdery buildup of boric acid was present on all cooling coil surfaces of the operating CACs. The boric acid was noted to be easily removable with water spray from a squeeze bottle. A team of personnel cleaned the CACs on November 18, 1998. From review of station log entries, the task group observed that personnel cleaned the CACs an additional 27 times from November 1998 through May 2001. Through interviews with station personnel, the task group learned that CAC plenum pressure was monitored by the system engineer, who would initiate maintenance tasks to have the CACs cleaned as plenum pressure approached an administrative limit of 1.4" w.g. The task group reviewed CAC plenum pressure data and noted that on occasion, CAC plenum pressure decreased below the 1.4" w.g. limit. The licensee stated that plenum pressure limit was a guideline only for initiating cleaning and that the CACs were operable based on the engineering evaluation discussed earlier for the 1992 CAC fouling event.

The task group noted that on several occasions, primary containment temperature exceeded the 120 degrees F limit of Technical Specification 3.6.1.5, which required that the condition be corrected in 8 hours or place the unit in hot standby in the following 6 hours. However, these occasions occurred typically in the summer months when service water temperature was warmer and CAC testing activities were being performed. There were no cases identified in which containment temperature exceeded 120 degrees F and the necessary corrective action to exit the technical specification action statement was CAC cleaning. The task group did not attempt to perform a detailed study of the correlation between CAC cleaning and containment temperature, but qualitatively concluded that boric acid fouling of the CACs did reduce their heat removal capability during normal operation.

The cleaning mechanism employed was a pressure washer using a kerosene fueled heater to heat demineralized water to assist in flushing the accumulated boric acid through the CAC coils and into the air plenum. During later CAC cleanings, the licensee switched to using an electric heater as the heat source for the water spray after a comment was made by the former plant manager that it was inappropriate to have open flames in containment. The task group requested a copy of the fire protection evaluation for acceptability of the equipment in containment that it did not pose a potential fire hazard that could adversely affect safe shutdown capability. The task group was informed that fire protection engineering personnel were consulted about the use of the kerosene-heated cleaning equipment prior to first use and that a hot work permit was required during the cleaning activity. However, no formal fire protection engineering evaluation for use of the equipment inside the reactor building had been performed. From review of station logs, the task group noted the following fire protection-related CAC cleaning entries: On April 10, 2000, during CAC cleaning during RFO 12, operators recorded in the log, "Received fire alarm in containment... no indication of a fire exists and a kerosene steam cleaner is being used to clean the CACs." On May 30, 2001, during online CAC cleaining, operators recorded in the log, "We will continue to perform the fire watch of containment by verifying stable CAC inlet temperature because access to containment will be limited." The task group concluded that remote monitoring of containment temperatures to detect fire was an inadequate substitute for a locally-staged hot work fire watch person with a fire extinguisher.

The task group concluded that online CAC cleaning activities had become a routine occurrence, almost as if it was a preventive maintenance task. The system engineer informed the task group that as soon as the CACs were cleaned, he would initiate another material deficiency tag to start the planning process for the next required cleaning. CAC cleaning activities even became a factor in scheduling other maintenance tasks. For example, the station log for December 29, 1998, identified that instrumentation and controls technicians had made a containment entry for a level transmitter maintenance task. The associated log entry stated that the recalibration of the instrument they had worked on would be scheduled to occur during the next containment entry for CAC cleaning. Containment entries for CAC cleaning had become so routine that other maintenance tasks would be planned around them. Additionally, CAC cleaning was being tracked as one of the highest radiation dose jobs during operating cycle 13.

As exemplified by the chronic nature of the CAC cleaning and radiation monitor RCS leakage detection system problems, these symptoms of RCS leakage became so much a part of the norm of everyday plant operation that the underlying causes of the condition were not corrected. Additionally, it was evident that every effort was being made to address these symptoms of the leak during power operation, but there was little objective evidence that the licensee was rigorously and thoroughly trying to address the source of the leak during outages.

3.2.1.2 Recommendations

3.2.1.2.1 Recommendations for NRC

3.2.1.2.2 Recommendations for Industry

3.2.1.1 Detailed Discussion

3.2.1.2 Recommendations

3.2.1.2.1 Recommendations for NRC

3.2.1.2.2 Recommendations for Industry

3.2.2 The Licensee Did Not Develop and Implement an Adequate Boric Acid Corrosion Program

3.2.2.1 Detailed Discussion

3.2.2.2 Recommendations

3.2.2.2.1 Recommendations for NRC

3.2.2.2.2 Recommendations for Industry

3.2.3 The Licensee Did Not Adequately Implement Owners Group and Other Industry Guidance

The licensee did not adequately implement B&WOG and other industry guidance relative to identifying VHP nozzle cracking and boric acid corrosion of the RPV head, nor were there any verification activities by B&WOG for all its members in response to Generic Letters 88-05 and 97-01 and their related submitals The licensee inspected the RPV head, but the presence of the insulation, the presence of significant amounts of boric acid deposits, and a lack of adequate tooling prevented a thorough inspection of the entire RPV head. A 1996 corrective action document noted that only 50 to 60 percent of the head was inspected. During the spring 2000 refueling outage, when it became apparent to the cognizant system engineer that the efforts to remove all the boric acid deposits from the head would not be successful, he consulted with the DBNPS regulatory affairs manager to ascertain whether enhanced visual inspections were a regulatory requirement. He was told it was not. Interviews of licensee personnel revealed that they were seemingly unaware, almost to a person, that boric acid deposits had to be completely removed from the head in order to assess whether there was VHP nozzle leakage.

A licensee environment that did not ensure plant safety was evident in: a lack of engineering rigor in the approach to problem resolution; untimely and cursory review of industry operating experience, both external and internal; and, a lack of compliance with plant procedures.

3.2.3.1 Detailed Discussion

Opportunities existed for the licensee to implement owners group and other industry guidance that could have resulted in the earlier detection of VHP nozzle leakage Examples of this information included: 1) the 1993 safety evaluations performed by the Babcock and Wilcox Owners Group (B&WOG) and NRC regarding VHP nozzle cracking, 2) the 1995 Electric Power Research Institute (EPRI) Boric Acid Corrosion Guide Book, and, 3) the vendor-proposed access opening modification to the RPV head support structure.

Correspondence between the NRC and PWR owners groups on VHP nozzle cracking

The NRC staff recognized that cracking of A600 RPV head nozzles was a potential safety concern in the early 1990s. Meetings were conducted with the individual PWR owners groups and NUMARC to address the issue. In 1993, the NRC requested that each PWR owners group provide a safety evaluation to document why no unreviewed safety question existed for A600 VHP nozzle cracking.

The Materials Committee of the B&WOG documented its safety evaluation in Report BAW-10190P, "Safety Evaluation for B&W-Design Reactor Vessel Head CRD Mechanism Cracking," dated May 26, 1993. The NRC staff responded with a safety evaluation report on November 11, 1993. The task group reviewed these documents and made the following observations:

Report BAW-10190P stated that RPV head nozzle inner cracks were expected to be axial in orientation and would require a minimum of 6 years to propagate through wall. Since the crack was expected to be axial in orientation and not circumferential, a control rod ejection accident was not possible. If a crack propagated through wall, above the nozzle to head weld, leakage was expected and a large amount of boric acid deposition on the RPV head was expected. Additionally, the report stated that once boric acid deposition occurred on the RPV head, wastage could initiate. B&WOG predicted that wastage of the RPV head could progress for 6 years before ASME Code limits were exceeded. However, B&WOG stated that the member utilities had developed plans to visually inspect the RPV nozzle area to determine if boric acid accumulation was occurring as a result of a through-wall crack. These inspections were stated to be part of the inspections each plant implemented for meeting its commitments to Generic Letter 88-05.

Leakage from a VHP nozzle crack was expected to quickly flash to steam, leaving behind a "snow" of boric acid crystals. The report stated that exposure of the RPV head to the dry boric acid crystals resulting from this type of leak has not resulted in wastage. The task group concluded that the B&WOG had not adequately assessed industry operating experience described in NRC Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion." Information Notice 86-108 described a condition discovered at another PWR where wastage of the RPV head from boric acid corrosion occurred due to a non-pressure boundary leak from an instrument nozzle conoseal.

The report discussed the issue of VHP nozzle flange gasket leakage that had been experienced at B&WOG member utilities, including DBNPS. Walkdown inspections of the flange gasket area were reported to be performed during every refueling outage and enhanced visual inspection of the VHP nozzle area were incorporated into the refueling outage inspections. If any leaks or boric acid crystal deposits were located during these inspections, an evaluation of the source of the leak and the extent of any wastage would be completed. Since a postulated VHP nozzle crack would result in a significant amount of boric acid crystal deposition on the head, inspections performed every refueling outage (every 18 to 24 months) would be expected to identify the boric acid accumulation and lead to detection of the crack prior to the calculated 6 years before excessive wastage would occur. Therefore, the VHP nozzle cracking issue was considered to not be an immediate safety concern or an unreviewed safety question.

The NRC safety evaluation of the PWR owners groups' safety evaluations documented the NRC staff's agreement with this conclusion. The NRC staff stated that a flaw would leak before it reached a critical size and would be detected during periodic surveillance walkdowns for boric acid leakage pursuant to Generic Letter 88-05. The NRC safety evaluation recommended that enhanced leakage detection by visually examining the RPV head be continued until either inspections had been completed showing absence of cracking or an on-line leakage detection system was installed in the head area. The task group concluded that this recommendation, which was generic to all of the PWR types, should have been understood as a requirement for enhanced visual inspection or an on-line leakage monitoring system for the Babcock and Wilcox PWR design because of the VHP nozzle flange gasket leakage issue discussed in the B&WOG report.

Leakage rates of greater than 1 gpm, the maximum limit for RCS unidentified leakage, would be promptly detected by the installed RCS leakage detection systems and would require a plant shutdown. However, plant technical specifications prohibited any RCS pressure boundary leakage The NRC staff acknowledged that some small RCS pressure boundary leakage might occur from VHP nozzle cracks, but it would be detected by observing boric acid accumulation on the RPV head during the refueling outage inspection prior to it becoming a safety concern. The NRC staff was concerned, however, that if a small leak developed shortly before a refueling outage, boric acid accumulation might not be detected and a plant might restart with a prohibited RCS pressure boundary leak. The NRC staff concluded that operating with such a leak would still not present a safety concern, but recommended that the industry consider installation of a system that could detect leaks significantly less than 1 gpm, to provide additional defense-in-depth to account for any uncertainty in the analyses. No domestic PWR implemented this recommendation.

The task group concluded from its documentation review that the NRC staff based its conclusion that no unreviewed safety question existed for the VHP nozzle cracking issue because B&WOG member utilities would perform the following actions:

- Conduct Generic Letter 88-05 inspections of the RCS to include the VHPs
- Conduct enhanced visual inspections of the RPV head
- Identify and correct VHP flange gasket leakage
- Perform boric acid evaluations for any identified leaks
- Remove boric acid upon detection because of the potential for wastage

The task group noted that the DBNPS response to Generic Letter 88-05 specifically identified that VHP flange gasket leakage would be identified and corrected.

The team concluded that the basis of the B&WOG safety evaluation regarding identification of VHP nozzle-leak, corrosion-induced wastage was dependent upon VHP flange gasket leakage being identified and corrected each outage. In order to determine if VHP nozzle leaks occur, any flange gasket leakage on the head must be identified and cleaned. As discussed previously, VHP flange gasket leakage at DBNPS was an ongoing maintenance problem.

Some of these leaks were not repaired after they were identified. Boric acid accumulation from these leaks was not completely removed from the RPV head and this precluded the capability to discover VHP nozzle crack leaks and corrosion-induced wastage.

The team also concluded that the NRC staff recommendation regarding enhanced leakage detection via visual head exams or installation of on-line leak detection systems in the head area was an ineffective mechanism for providing assurance that CRDM nozzle cracks were promptly identified and corrected. No serious effort was made by the industry to develop and implement an on-line leakage detection system for the head area.

In a December 13, 1993, addendum to Report BAW-10190P, the B&WOG stated that they performed an evaluation of both on-line and off-line leak detection systems. The conclusions reached from this evaluation were that the Generic Letter 88-05 walkdown visual inspections of the reactor vessel head areas provided adequate leak detection capability.

During interviews with DBNPS engineers and managers, the task group determined that DBNPS personnel had minimal knowledge and understanding of the content of Report BAW-10190P and the accompanying NRC safety evaluation. The RCS system engineer stated that he had never read these reports. A DBNPS design engineer who was responsible for performing RCS boric acid corrosion evaluations had been a member of the B&WOG materials committee since 1994. He stated that until this event, he did not recall that the report discussed wastage of the RPV head. His understanding was that dry boric acid crystal accumulation on the RPV head would not cause wastage. Additionally, he stated that plant engineering staff did not know that boric acid with red discoloration was indicative of boric acid corrosion of carbon steel. The task group noted that this was inconsistent with Condition Report 00-0782, initiated on April 6, 2000, during the RFO 12 refueling outage. The condition report identified that red, lava-like boric acid was observed on the RPV flange coming from the RPV service structure weepholes and that corrosion was present.

From interviews with DBNPS staff, the task group determined that an inadequate feedback mechanism existed for ensuring that owners group reports such BAW-10190P were reviewed upon receipt to incorporate actions into the DBNPS commitment tracking system. The DBNPS B&WOG Materials Committee member stated that reports such as this would be distributed to staff for information, but there was no means to ensure that required actions were incorporated into their commitment tracking system. Therefore, there was no assurance that required actions would be incorporated into station procedures.

One commitment was identified in the licensee's commitment tracking system database, A16892, relative to these issues. Commitment A16892 was simply a tracking item to ensure that the B&WOG responded to the NRC staff with its safety evaluation. It was inadequate to ensure that the bases of the B&WOG safety evaluation, accepted by the NRC staff, would be implemented at Davis-Besse. It was closed with a statement that proper visual inspection would be performed during the 1994 refueling outage (RFO 09).

PCAQR 94-0295 was initiated on March 17, 1994, when it was believed by the former RCS engineer that Commitment A16892 was inappropriately closed. The PCAQ was closed on May 9, 1994, because the licensee concluded that Generic Letter 88-05 inspections of the RCS were sufficient and acceptable to the NRC for inspection of the reactor vessel head penetrations. Closure documentation stated that enhanced visual inspection was an NRC recommended action, but was not required. Additionally, closure documentation stated, "Due to the fact that no cases of head cracks have been identified in the United States and boric acid leakage through the CRDM flanges is low, he doesn't think that there is significant risk of a crack being present. In addition, the inspection methods presently available to us are not highly reliable. Therefore, he does not believe that it is necessary to perform the inspections at this time."

The task group interviewed a former chairman of the B&WOG, who was the B&WOG chairman at the time BAW-10190P was submitted to the NRC. The former chairman was asked whether the B&WOG performed any reviews of member utility implementation of actions, documented on the behalf of the member utilities, in B&WOG reports to the NRC. The former chairman indicated that this was generally not the case. It was assumed that since the member utilities had representatives on the B&WOG committees, those representatives would be expected to ensure actions applicable to their plant would be implemented. He stated that the B&WOG did conduct some individual plant reviews to assist the member utilities in some technical issues areas. As an example, he stated that member utilities were visited to review implementation of some integrated control system projects.

EPRI Boric Acid Corrosion Guidebook

Information relevant to the identification of RCS leakage and development of an effective boric acid corrosion control program was provided in the Boric Acid Corrosion Guide Book, issued by EPRI in April 1995.

Section 6.2.2, "Methods to detect leak rates less than about 0.1 gpm," provided two specific guidelines:

- containment air cooler thermal performance as observed in coil heat transfer degradation
- consideration for monitoring the boric acid concentration in the containment air cooler condensate

Guidance was also provided, under "other potential indicators," for the assessment of high containment particulate radioactivity monitoring results.

Service Structure Access Opening Modification

This modification was originally initiated by the licensee in Request for Modification (RFM) 90-0012, on March 21, 1990. The modification included the installation of several large access openings in the service structure which would eliminate the cumbersome and difficult method of accessing the reactor vessel head penetrations via the weep holes located at the base of the service structure. The initiator's request documentation included: "Boric acid has leaked from the CRD flanges and has accumulated on the reactor head. The reactor head is carbon steel and is therefore susceptible to degradation. Install multiple access ports with closure plates in the closure head to permit cleaning and inspection of the reactor head."

This RFM was voided on September 10, 1992. The basis for voiding stated: "This modification was initiated to allow easier access for inspection of CRDM flanges and for cleaning of the reactor vessel head. Current inspection techniques using high powered cameras preclude the need for inspection ports. Additionally, cleaning of the reactor vessel head during last 3 outages was completed successfully without requiring access ports."

The service structure access opening modification was initiated again on May 27, 1994, as RFM 94-0025. The initiator's request documentation stated:

> First, there is an ongoing industry concern involving corrosion of the Inconel 600 CRDM reactor vessel nozzles. There is no access to the reactor vessel head or the CRDM reactor vessel nozzles without the installation of this modification Second, inspections of the reactor vessel head for boric acid corrosion following an operating cycle is difficult and not always adequate. Video inspections of the head for the CRDM nozzle issue and as a follow-up to the CRDM flange inspection do not encompass a 100% inspection of the vessel head. Third, cleaning of excessive boric acid residue from the reactor vessel head also does not encompass 100%. The size and geometry of the service structure mouse holes with scrapers and wire brushes only permits cleaning of the lower one-third of the head surface area

RFM 94-0025 was not canceled, but it was deferred on at least 11 occasions by the licensee's Project Review Group or Work Scope Committee to future outages. The task group reviewed the meeting minutes from these meetings. The licensee's basis for deferral was that although implementation of the modification was desirable, it was not required from a safety perspective and it was not implemented at all other Babcock and Wilcox units. The task group concluded that implementation of the service structure access modification would have facilitated the inspection of the RPV head area, the removal of boric acid accumulation from flange leaks to enable identification of VHP nozzle crack leaks, and the identification of corrosion-induced wastage.

3.2.3.2 Recommendations

3.2.3.2.1 Recommendations for NRC

- Assess the practice of resolving safety issues via communications with industry owners groups to determine if this practice is appropriate rather than direct communications with individual licensees.
- Review the legal status of owners group communications with the NRC to determine if actions or commitments identified by the owners groups on behalf of their member utilities are enforceable upon individual licensees.
- Perform a review of NRC safety evaluations of owners group submitals to identify what actions were assumed by the staff to be implemented by individual licensees to support the NRC staff's conclusions.
- Develop a process for the communication of NRC safety evaluations of owners group submitals to the affected licensees and the NRC regional offices.
- Develop an inspection procedure for regional office inspector verification of implementation of owners group commitments made on behalf of their member utilities at the affected plants and provide inspection resources to implement this verification.
- Perform an audit of implementation of past owners group commitments for individual licensees to ensure the bases of the NRC's safety evaluation conclusions remain valid.

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- Implement periodic inspections of licensee operating experience programs

3.2.3.2.2 Recommendations for Industry

- Audit owners group submitals made to the NRC on their behalf to ensure commitments, explicit or implied, are incorporated into the commitment tracking system. Ensure that required actions have been implemented.

- Ensure that feedback mechanisms exist and are implemented to perform adequate review of owners group reports to ensure that site-specific actions are taken as required.

3.2.4 The Licensee Did Not Learn From Operating Experience

DBNPS failed to adequately evaluate and incorporate operating experience related Alloy 600 nozzle cracking and boric acid corrosion into its programs and processes. Many licensee personnel did not understood the symptoms of VHP nozzle leaks nor the implications of leakage from systems containing boric acid. The licensee's industry operating experience program did not specify a review of licensee event reports. Had they done so they may have identified many instances of Alloy 600 nozzle cracking in all the other B&W plants and in many Combustion Engineering plants, as well as instances in which licensees expected to find dry boric acid crystals rather than highly corrosive wet boric acid solutions. There was a long history of the licensee accepting and operating with RCS leaks. This reinforced the notion among licensee manager and staff that it was acceptable to not remove the buildup of boric acid deposits on equipment upon discovery. In two notable DBNPS instances in 1992-1993 and 1998, significant boric acid corrosion of carbon steel components in the RCS were identified. The licensee identified lessons-learned from the latter event that are essentially the same as the lessons-learned from the RPV head degradation event. While training was provided to some of the involved staff, these lessons, inexplicably, were not sufficiently internalized to the degree necessary to result in a more timely identification of the VHP nozzle leaks and RPV head corrosion in the spring of 2000. Had they reviewed NRC NUREG information, they would have learned that for B&W plants, peripheral VHP nozzles were not more likely to experience cracking as was believed. In fact, the data suggest that the RPV head dome center VHP nozzles, such as DBNPS VHP Nozzles 2 and 3, were more likely to experience cracking.

3.2.4.1 Detailed Discussion

Davis-Besse failed to learn and implement appropriate actions in response to operating experience gained at other B&W plants, other PWRs, and experience gained at their own facility concerning boric acid leakage and corrosion. It also appears that some important lessons learned by DBNPS also were not retained, in that boric acid crystal buildup on components was later viewed as not significant.

(23) Davis-Besse Failed to Learn from NUREG/CR-5576, "Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Plants" and in IN 86-108 regarding RPV head wastage by boric acid corrosion at Turkey Pt. 4 and at Salem 2. Similarities in these two

events with the DBNPS event include the desire to continue operations for a few additional months, and a significant underestimation of the boric acid corrosion rate. Turkey Point management continued to rely on the initial faulty safety evaluation and determination that the situation was acceptable for continued operations, and management decisions were made with lack of adequate information concerning the scope of the potential problem.

Turkey Pt RPV Head Wastage Event

In August 1986, a leak was discovered in one of four reactor head instrumentation port column assembly. Following an engineering evaluation, the site decided that it would continue operations for an additional six months. In October 1986, following another reinspection, it was determined that the plant could continue operations for another six months. In March 1987, an airlock failure forced the plant to shut down. A reinspection of the instrumentation port discovered a large accumulation of boric acid (approximately 500 pounds). During the short period of time from October 1986 to March 1987, the boric acid accumulation resulted in general corrosion on the instrument port column assembly, control rod drive mechanism coolers, CRDM coils, electrical connectors, closure head, cables, control equipment, various instruments and vessel head insulation. The RPV head wastage amount was not characterized in NRC documents There was evidence of some pitting and corrosion on the RPV head with the largest amount of near the leaking instrumentation penetration. In March 1987, corrosion rates were estimated to be double that previously assumed by the licensee. The AIT report concluded that the Turkey Pt. engineering inspection [of the leaking instrumentation penetration] failed to consider the potential for widespread effects of leakage in the head area beyond the readily accessible, visible areas. FP&L management continued to rely on the initial faulty safety evaluation and determination that the situation was acceptable for continued operations. Management decisions were made with lack of adequate information concerning the scope of the potential problem. This event was included in IN 86-108, Supplement 1.

Salem 2 event Head Wastage Event

In August 1987, boric acid crystals were found on a seam in the ventilation cowling of the reactor head area The accumulation was approximately 15 cubic feet in volume. The leak was the result of pin holes in the seal weld located at the base of the thermocouple instrumentation threaded connection. The corrosion depth in the RPV head ranged from 0.36 to 0.40 inches deep for pits from 1 to 3 inches in diameter.

(24) The 1998 Davis-Besse pressurizer spray valve (RC-2) event involved significant boric acid corrosion of valve fasteners (three body-to-bonnet nuts were severely degraded, one nut was 30% dissolved, a second 93% dissolved, and a third was 100% dissolved). The event occurred over time from May through September 1998. The RC-2 event was of such significance that a site-wide stand down meeting was held on January 21, 1999, to review the event, including the effects of boric acid corrosion on carbon steel, the importance of maintaining material compatibility, and the advantages and limitations on the use of on-line leak sealants. Greater sensitivity to the effects of boric acid corrosion on plant equipment and integration of these insights into plant processes and operational philosophy were to be institutionalized by: 1) developing a revision to the Boric Acid control program and the Work Process Guideline on plant leakage, including

the benchmarking of industry standards for monitoring, evaluating, documenting and controlling boric acid leakage; and, 2) providing additional training to management and the technical staff to address the technical issues of boric acid control, the Davis-Besse Boric Acid Control Program and requirements, lessons learned from the RC-2 event, and industry experience. Additional management issues involving oversight, and reinforcing the philosophy of conservative decision making were being addressed by the site Corrective Action Program.

The following lessons learned from the RC-2 event were subsequently presented in an EPRI Boric Acid Corrosion Workshop in May 2001 by a Davis-Besse engineer:

- Less than Adequate Material Segregation
- Less than Adequate Knowledge of Past History
- Acceptance of substandard equipment performance
- Didn't recognize red/brown boric acid equaled major wastage
- Felt that discoloration was due to minor yoke corrosion
- Didn't recognize potential for high corrosion rate
- Boric Acid was not removed for all inspections

Most of the lessons learned from the RC-2 event are applicable to the licensee's 2002 VHP nozzle leakage and RPV head corrosion discovery, and in fact, should have prevented the problem from occurring to the extent that was identified in February 2002.

(3) Control Rod Drive Mechanism Nozzle Cracking and Leakage Had Previously Occurred at All Other B&W Plants

Table X, "CRDM Penetration Cracking Experience at B&W plants," provides information on the crack location on the RPV head, crack type, extent of NDE (other than cursory visuals) on the CRDMs, number of operating years prior to event report, and the event date. As shown in Table 1, B&W plants have had 6 percent of their CRDM penetrations develop through wall cracks, 100 percent of B&W plants have had axial CRDM penetration cracks, and 86 percent of B&W plants have experienced circumferential cracking in at least one CRDM penetration. In addition, Davis-Besse was aware that all of the other operating B&W plants had experienced axial and/or circumferential CRDM penetration cracking prior to their own discovery of the same in February 2002. As shown in the table, Davis-Besse was the last B&W plant to report cracking. However, had the boric acid crystal buildup that was identified during the 1996 refueling outage, the 1998 outage and the 2000 outage that was allowed to accumulate been removed, it may have been determined that CRDM penetration cracking had occurred long before February 2002, and probably in 1996
The "Row" designations used in Table X are defined as follows: Row 1 includes nozzle #1; Row 2 includes nozzles #2-9; Row #3 includes nozzles #10-25; Row #4 includes nozzles #26-45; and Row #5 includes nozzles #46-69.

(4) Davis-Besse realized that the CRDM nozzle location on the RPV head influenced the probability of CRDM cracking but was unaware that the probability varied differently for B&W plants than for other PWR designs.

An AEOD study issued by INEL in October 1994, NUREG/CR-6245, "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking," provides insights for PWRs . It does mention that circumferential cracking of CRDM nozzles had occurred (at a much earlier operational period than Oconee 3), and that differences existed between B&W plants and other PWRs DBNPS was not aware of the uniqueness of B&W plants concerning CRDM cracking.

It was a common understanding at DBNPS and the NRC that there was a higher probability of CRDM cracking in the CRDM nozzles that were located on the periphery of the RPV head because of the angle of the head and the CRDM. Concerning nozzle cracking, the NUREG/CR states that (as of 1994) "Most of the nozzle cracks were short and axial, making a small angle with the vertical, initiated on the inside surface, and located at either the uphill or downhill side of the peripheral nozzles and near the partial penetration weld. The maximum angle of inclination was about 30 degrees. Circumferential indications were found at three plants These were on the outside surface of nozzles at Bugey 3, in the attachment weld at Ringhals 2, and at Zorita." The NUREG/CR also states that "Under operating conditions, the peak stresses in peripheral nozzles are higher than those in the central nozzle at most plants except at the B&W-designed plants where the peak stresses (hoop stresses) in the peripheral nozzles and central nozzle are of similar magnitude but are still higher than the axial stresses. Therefore, in most plants, except in the B&W -designed plants, the peripheral nozzles are more likely to develop axial cracking than the central nozzle; most cracks have been found in the peripheral nozzles."

3.2.4.2 Recommendations

3.2.4.2.1 Recommendations for NRC

3.2.4.2.2 Recommendations for Industry

Table X Control Rod Dnve Mechanism Penetration Cracking Expenence at B&W plants

CRDM ROW	CRDMs PER ROW	TOTAL	OCO1	OCO3	ANO1	OCO2	CRY3	TMI1	OCO3	DB	PROBABILITY %
1	1	7								1	14% of Row 1 had cracks
2	8	56		2		2			1	3	14% of Row 2 had cracks
3	16	112	1	2		1		1	1		6% of Row 3 had cracks
4	20	140		2	1	1	1	4	3		9% of Row 4 had cracks
5	24	168		3				3	2	1	5% of Row 5 had cracks
THRU WALL CRACK			1	9	1	4	1	3	5	3	6% of CRDMs have expenenced thru wall cracks
AXIAL CRACK			YES	YES	YES	YES	YES	YES	YES	YES	100% have had axial cracks
CIRC CRACK			NO	YES	YES	YES	YES	YES	YES	YES	86% have had circumferential cracks
100% INSP			NO	NO	NO	NO	NO	YES	YES	YES	43% of the units had 100% NDE
OP YEARS PRIOR TO EVENT			27	27	17	27	24	27	27	24	
EVENT DATE			12/4/00	2/18/01	3/26/01	4/28/01	10/01/01	10/12/01	11/12/01	2/27/02	

X

3.2.5 The Licensee Failed to Provide Adequate Resources, Oversight, Guidance and Expectations in the Conduct of Safety Related Work Activities

The licensee did not foster an environment, by providing adequate oversight and resources, to ensure that plant safety was appropriately maintained. Management's failure to lead by example, failure to set high standards, and lack of involvement of important issues resulted in expectations that were contrary to plant safety. These factors directly contributed to the lack of timely identification of the VHP nozzle leaks and boric acid corrosion wastage. The task force identified numerous performance lapses in multiple areas spanning the past 10 years that, when considered collectively, were indicative of a poor safety culture. These included: engineering resources that were stretched thin by budget and staffing cuts; an imbalance between production focus and safety focus as evidenced by taking symptomatic actions that did not impede power operations while not implementing rigorous and thorough corrective actions during outages because of budget and scheduler concerns; a lack of management involvement in important safety significant work activities and decisions; a lack of a questioning attitude by senior managers; a lack of engineering rigor in the approach to problem resolution; a long-standing acceptance of degraded equipment; the inability to recognize or address repetitive or recurring problems; ineffective and untimely corrective actions; the cancellation or deferral of safety-related work based on budgetary or scheduler considerations; ineffective self-assessments of safety performance, a lack of ownership of plant problems; and other indications of an unhealthy safety conscious work environment.

3.2.5.1 Detailed Discussion

There was a significant decrease in staffing and operating budgets during the 1990's, particularly in the areas of engineering and capital improvements (e.g., permanent modifications). In 1992 approximately 1281 permanent staff positions were filled. In the following years, decreases continued until 2001 when the staffing reach its lowest point of approximately 656 permanent staff positions. This reflects a decrease of approximately 49% of the Davis-Besse staff in a nine year period. The team reviewed the ____ expended budgets for years 1991 through 2001 and adjusted the amounts to account for inflation. STATE CONCLUSIONS OF THESE DECREASES

Based on interviews results and workload assignments, the team concluded that system engineers were spread thin, with multiple system assignments and collateral duties An example of this was the system engineer, who was responsible for the ____ systems, also being the boric acid corrosion control coordinator. In reviewing cases of boric acid corrosion at DBNPS and boric acid corrosion related issues, the team concluded that the boric acid corrosion control program lacked effective oversight and ownership. The coordinator's workload had some impact on this item. There was high turnover among the system engineers, which adversely affected their knowledge base. This was most clearly illustrated by the large number of engineers who were involved with reactor head inspections and dispositioning of boric acid deposits on the head during the previous ten years. Five different engineer were involved with head inspections during the 1996, 1998, and 2000 RFOs. In discussions with another B&W plant that had experienced VHP nozzle cracking, they told the team that engineering continuity was a key factor in their ability to identify and correct leaks early.

Information obtained from licensee records and interviews of DBNPS personnel indicated an overemphasis on production, as evidenced by significant activity to address symptoms of RCS leaks (e.g., CAC and radiation monitor filter element fouling) while operating at power but not developing or implementing rigorous plans to find the source of the leaks during outages because of the apparent impact of those plans on outage schedules or budgets. Additionally, the licensee would routinely restart the plant following a refueling outage with leaking RCS valves and CRDM flange leaks that were not repaired during the outage. Interviews with Davis-Besse personnel provided mixed views on schedule pressures. Some individuals believed that work is schedule driven such that it would have a negative impact on work performance, while others stated that management was schedule focused, however, safety remained a priority. According to the RCS system engineer, the equipment used for the head cleaning during the 2000 RFO was removed without first consulting with him even though he was the leader for the activity. The reactor head was scheduled to be moved back to the vessel on the day the cleaning equipment was removed. The LLTF concluded that a schedule driven work environment contributed in the lack of completed reactor vessel head cleaning that was performed during the 2000 refueling outage.

The continuous nature of RCS leakage symptoms demonstrated Davis-Besse's willingness to accept degraded plant conditions, provided any related conditions that threatened plant operations could be resolved. Actions to address CAC and radiation monitor filter element fouling were highly visible and received strong management attention. While the cause of the fouling, RCS leakage, received considerable attention initially, more recent efforts to identify the source of RCS leakage were not aggressive. For example, in the 2000 RFO only routine inspections to identify containment leaks were performed at the beginning of the outage and for the 2002 RFO management elected to not perform the Mode 3 RCS walkdown. This decrease in efforts to resolve a problem that has existed for an extended period of time is indicative of management's willingness to live with problems and lack of commitment to resolve issues that clearly have the potential to be significant

There appeared to be a lack management involvement on important safety significant work activities and decisions. Engineers were apparently often left to make important decisions without management interaction. For example the 2000 refueling outage RPV head cleaning was discontinued once the cleaning equipment was removed but it is unclear if any managers were aware at the time of the amount of boric acid that remained on the head and agreed with the decision to stop the cleaning. The practice of supervisors and managers being assigned to the outage management structure during RFOs and having individuals "act" in manager's normal role contributed to management being somewhat disengaged with issues they were responsible for. An example was the decision to use water as part of the head cleaning in the 2000 RFO. Because of outage work, the supervisor did not have discussions with the system engineer regarding this controversial issue. At times, senior management did not exhibit a questioning attitude. The former DBNPS vice president (VP) stated in an interview that he had no followup involvement with 2000 RFO RPV head cleaning activities once he gave approval to use water for the cleaning. The team questioned this decision given the long history of RCS leakage and the condition of the boric acid deposits (described in the CR as large quantity and red/ brown in color) found on the head at the beginning of the outage. In his interview, the VP stated that he viewed the video tape of the as-found condition of the head.

During the review of CRs and interviews with DBNPS personnel, the team identified a longstanding pattern of problem resolutions which lacked engineering rigor. Examples dated back to 1992 when fouling of the CACs was allowed, in part, on the presumption that steam from a LOCA would clean the CAC and ensure that CAC cooling satisfied design basis

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assumptions. No technical basis was available to support the steam cleaning theory. Additional issues which lacked engineering rigor included: the belief that leakage from the pressurizer relief valves was the source of boron accumulation on CACs and radiation monitor filters without consideration that the discharge from the relief valve was from the pressurizer steam space; system engineering not informing operations that saturation of iodine detector on the containment radiation monitor would cause the detector to be unavailable for up to __ hours; and the resolution to CR 2000-1037 not addressing the observation that a lack of positive evidence that a CRD flange was leaking provided a high probability of a leaking CRD. ***DO WE HAVE OTHER OR BETTER EXAMPLES???***

Corrective actions to resolve plant issues, some which were classified as significant, were often untimely and ineffective in preventing recurrence of similar type problems. The corrective actions in response to the RC-2 event outwardly appeared to be adequate, however, when the team reviewed these actions in detail, several problems were noted. The boric acid corrosion control training that was provided to the DBNPS technical staff did not include some individuals who later were involved with the boron deposits that were found on the reactor head inthe 2000 RFO. In addition, some individual who received the training did not understand the implication of reddish/ brown boric acid being an obvious indication of carbon steel corrosion. Improvements to the boric acid corrosion control program that were made via a revision to procedure, NG-EN-00324, Boric Acid Corrosion Control, were incomplete. When the team reviewed the revised procedure additional problems/ weaknesses were identified. It should be noted that in 1992, corrosion of a steam generator occurred due to RCS leakage from a flanged connection which was not corrected when it was first discovered. While the team did not review the corrective action for this event in detail, the similarities with the RC-2 indicate the 1992 event corrective actions were ineffective. ***NEED ADDITIONAL EXAMPLES OF CORRECTIVE ACTION PROBLEMS***

The cancellation or deferral of safety-related work was directly linked to the RPV head degradation experienced at DBNPS. The two primary examples were the deferral of the RPV service structure access opening modification and deferral of repairs for leaking CRD flanges. The access opening modification was initially proposed in 1990, then through a series of cancellations and deferrals the modification was schedule for the 2004 RFO at the time the RPV head degradation was discovered. The team interviewed DBNPS personnel involved with this modification and reviewed related documents, such as schedule and budget committee meeting minutes and modification packages. The team concluded these delays resulted from budgetary and scheduling considerations and the lack of a knowledgeable sponsor who understood the importance of a complete head visual inspection and removal of boron deposits from the head. The program that was developed to rank the severity of CRD flange leakage and allow deferral of leak repairs illustrates the efforts that DBNPS would take to ensure work such as CRD flange leak repairs would not interfere with outage schedule and minimize outage cost. Since vendor support was used for flange repairs, budgetary considerations factored into the decision to delay the work.

DBNPS lacked a self-critical perspective and when self-assessments of safety performance were performed they were ineffective. During the approximate three years that symptoms of RCS leakage in containment existed, there was no indication that management attempted to obtain outside assistance to help identify the source of leakage. The Quality Assurance assessment report for 2000 RFO activities discussed observations of the boric acid corrosion control program implementation and cleaning of boron deposits from the head. The report executive summary listed, "Aggressive cleaning of boric acid accumulation from the Rx head" as a positive attribute. Discussions in the body of the report included, "The audit team evaluated the implementation of the boric acid corrosion control program. Team members participated and reviewed Mode 5, Mode 3, and RCS hydrostatic inspection results... Boric acid leakage was adequately classified and corrected when appropriate. Engineering displayed noteworthy persistence in ensuring boric acid accumulation from the reactor head was thoroughly cleaned". In interview with QA personnel, they stated the audit results for head cleaning was based on a review of the condition report. The auditors did not observe actual head condition, cleaning activities, nor video tapes. The team concluded this audit was ineffective, lacked appropriate rigor, and may have contributed to management's inattention since QA's perspective was clearly positive for head cleaning and boric acid corrosion control activities

3.2.4.2 Recommendations

3.2.4.2.1 Recommendations for NRC

- Review the range of NRC baseline inspections and assessment capabilities to determine if sufficient activities are inplace to detects the types of problems experienced at DBNPS or if addition oversight activities are needed

3.2.4.2.2 Recommendations for Industry

- Each commercial nuclear power plant should perform indepth case study review of the Davis-Besse head degradation event to ensure they do not have similar problems and weaknesses

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3.3 The NRC Did Not Accurately Assess the Safety Performance of the Davis- Besse Nuclear Power Station

The NRC did not adequately assess the safety performance of Davis-Besse. While the symptoms of the RCS leaks and other related issues were known and received some inspections of individual issues, there was no integrated or focused inspection follow-up. Communication breakdowns, involving both NRC and Davis-Besse, also contributed to the lack of timely identification. Historically, the regional and headquarters program office viewed DBNPS as a good performer, which may have contributed to a lack of effectiveness in integrating the known information. During this period there were a number of plants of high regulatory concern, which distracted management attention and resulted in a number of staffing and resource challenges impacting the entire region. Licensing process guidance and implementation problems represented additional missed opportunities.

3.3.1 The NRC Did Not Adequately Assess the Symptoms of RCS Leakage

Specifically, the NRC did not adequately assess the symptoms of the VHP nozzle leaks even though there were many opportunities over the past several years to have done so. The symptoms of an active RCS leak, including the boric acid fouling of the containment air cooler (CAC) fins and containment radiation monitor filter elements, were known by various members of the Region III and headquarters staff for a period of several years, but this did not lead to focused actions that could have resulted in the earlier identification of the VHP nozzle leaks. There were a number of highly visible actions taken by the licensee to address the symptoms of the active RCS leaks. Some of these actions were inspected by the NRC while others were not.

3.3.1.1 Detailed Discussion

Numerous symptoms of RCS leakage inside the Davis-Besse containment existed from 1998 until the unit was shutdown for the 2002 refueling outage (13 RFO). While the NRC inspection effort reviewed many of these symptoms, there was limited assessment and analysis of Davis-Besse's efforts to identify and resolve RCS leakage. Some inspections recognized and specifically focused on RCS leakage, while other inspections reviewed areas which related to RCS leakage. The inspections in these related areas did not address RCS leakage as part of their assessment of Davis-Besse's performance. Many of the symptoms of RCS leakage when reviewed individually, provided minimal insights into the actual degraded condition of the reactor head. To fully assess and recognize the resulting condition of the RCS leak in containment, i.e., reactor head degradation, an integrated assessment of the symptoms was required. The NRC failed to perform an integrated review the RCS leakage symptoms

For the time period of 1998 to February 2002, unidentified RCS leakage (monthly average) ranged from the normally low value of less than 0.1 GPM to a maximum of 0.8 GPM. The primary cause of the higher leak rate was a change to the pressurizer relief valve discharge piping in October 1998. Once the normal discharge piping configuration was restored in May 1999, the leak rate decreased, but values ranged between 0.1 to 0.3 GPM until February 2002.

The specific indications of RCS leakage in containment included the following:

- There was an increase in unidentified RCS leakage which could not be correlated to any specific source following restoration of pressurizer relief valve discharge piping to its normal configuration;

- The CACs experienced fouling as boric acid particles in the containment atmosphere collected on the CAC cooling fins. As the amount of boric acid fouling increased, corresponding changes in CAC plenum pressure would be seen on the remote indication in the control room. In response to changing plenum pressures the CACs were cleaned 17 times from November 1998 to May 1999. The change to the pressurizer relief valve discharge piping in October 1998 which also directed relief valve seat leakage to the containment atmosphere was viewed by the licensee as the primary cause of the CAC fouling. Eleven additional CAC cleanings were required following restoration of the relief valve discharge piping until the unit was shutdown for in February 2002. The frequency of CAC cleaning was higher during the earlier periods of the fuel cycle. This is consistent with higher concentration of boric acid in the RCS at the start of the fuel cycle and the gradual reduction of RCS boric acid over the fuel cycle.

- The containment radiation monitors also experienced fouling of boric acid particles on the filter elements. Air samples are continuously drawn from within containment, passed through a particulate filter, an iodine sample cartridge and a noble gas detector before being exhausted back into containment. The buildup of boric acid on the filters would reduce air flow to a point that filter change out was required. To accomplish this the radiation monitor was taken out of service. Prior to the boric acid fouling, the radiation monitor filters were replaced each month as routine maintenance. Starting in late 1998, the filter change outs increased to weekly, then cycled between daily to an irregular one to two week replacement interval. In May of 1999, the radiation monitor filters began accumulating a yellowish-brown material. The laboratory analysis of the material identified the presence of ferric oxide. Specifically, this analysis stated, "The fineness of the iron oxide (assumed to be ferric oxide) particulate would indicate it probably was formed from a very small steam leak."

- In each of the 1996, 1998, and 2000 refueling outages a visual inspection of the reactor head identified an accumulation of boric acid. A corrective action document was initiated for each occurrence to address the condition.

- Evidence of boric acid deposits was noted on numerous surfaces in containment. During containment walkdowns by the team, rust on carbon steel surfaces of service water piping, cable trays and covers, and CACs was observed. Boric acid residue was also noted on these surfaces. The amount of rust was directly related to the corrosive nature of boric acid on carbon steel. During a review of the control room log the team noted a May 22, 1997, entry which stated boric acid buildup was noted on the inside of the incore tank and on CAC number two.

Based on the available symptoms and interviews with Davis-Besse and NRC personnel it was clear to the team there was widespread knowledge of RCS leakage in containment and that the leakage persisted over a period of several years. The senior resident inspector and division of reactor projects (DRP) branch chief stated in interviews they were aware of the leakage and that they engaged the licensee on their efforts to identify and resolve the leakage. The DRP branch chief maintained a daily logbook of plant status and issues which were discussed with the residents inspectors. The branch chief stated his normal practice was to discuss the majority of these issues in the RIII morning meeting with regional management. The team was provided a copy of the branch chief's daily logbook for the period from _____ to present. The team noted that symptoms of the RCS leakage, included at power containment entries to clean the CACs and TS action statement entries due radiation monitor filter replacement were mentioned in the logbook.

The NRR project manager for Davis Besse during 1999 participated regularly on the morning status calls held by the Region III staff at the branch level. He recalled that boric acid buildup was discussed and that the licensee was making efforts to find RCS leaks through walkdowns, and that the licensee attributed the buildup to leaking pressurizer safety valves. Containment air cooler fouling was also discussed in these calls, and was a concern because of elevated containment air temperatures during the summer months. He assumed that the Region III staff were observing licensee efforts to address the issues.

Senior management in RIII did not have the same level of awareness of the symptoms nor of the continuous nature of the RCS leakage in containment. In an interview one manager recalled problems with radiation monitor fouling because of the associated TS action statement entries and another manager said that he was briefed on CAC cleaning. The other managers stated they did not recall hearing about or discussing these items. The team concluded there was distinct difference in the level of knowledge on Davis-Besse RCS leakage and the symptoms between the branch chief and senior regional managers.

In interviews with the resident inspectors they stated that regional managers did not provide feedback on RCS leakage or the symptoms in the form of inspection guidance to the residents. The branch chief discussed RCS leakage and the symptoms with the residents in an efforts to understand the licensee's position on the source of leakage and their plans to resolve the leakage. In an interview the branch chief stated that during site visits to Davis-Besse, he routinely discussed RCS leakage activities with the licensee.

For the period of February 13 - September 13, 1999, five consecutive resident inspector inspection reports (each covering a 6-week period) discussed inspections which related to RCS leakage. The inspections focused primarily on the April 24 - May 10, 1999 midcycle outage activities. While there was some assessment of licensee activities, the majority of reports described the RCS leakage, related conditions, such as radiation monitoring fouling, and the licensee's plans to resolve the leakage. Following the midcycle outage the inspection reports discussed the reduction in RCS leakage but recognized that radiation monitor filter fouling continued to occur and that the filters had accumulated a dark colored particulate which was determined to be primarily iron oxide (a corrosion product). In the last of these inspection reports which discussed RCS leakage, the inspectors stated that the source of corrosion products was still unknown and that the licensee planned to perform thorough inspections of the containment during the next refueling outage to detect the source. In reviewing subsequent Davis-Besse inspection reports, the team found no other inspections of licensee's efforts to resolve RCS leakage. NRC Inspection Report No. 50-346/01-013 discussed a temporary modification to bypass the charcoal filters on the containment radiation monitors. This related to RCS leakage in that the filter were bypassed because of moisture clogging the charcoal. High humidity in the containment from the RCS leakage was a probable source of moisture.

Several assumption made by Davis-Besse regarding RCS leakage were questioned by the team and were considered additional opportunities for the NRC to more aggressively assess Davis-Besse efforts to address RCS leakage. Davis-Besse believed that a significant contributor to CAC fouling was leakage from the pressurizer relief discharge piping that was

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temporarily vented into containment atmosphere. NRC Inspection Report No. 50-346/99-004 discussed the relief valve leakage evaporating into the containment atmosphere, condensing on the CACs and degrading their performance to the point that cleaning was required every 10 -14 days. Based on leakage from the pressurizer steam space (the part of the pressurizer where the relief valves are attached to) being at a lower boron concentration that the RCS, the team questioned how much boric acid would actually be released from relief valve leakage. It did not appear this was assessed by Davis-Besse in 1999. During the LLTF review, Davis-Besse responded to the team that some boric acid would carryover into steam at high RCS pressures but the amount would be significantly less than a RCS leak. From interviews with NRC staff and review of inspection reports the team concluded this issues was not previously reviewed. Davis-Besse also believed that one of the most likely sources of RCS leakage that was causing CAC and radiation monitor fouling was CRDM flange leakage. This was based a long history of CRDM flange leakage. During the 1999 midcycle outage, CRDM flanges were inspected and no leakage was identified. This was not recognized by many Davis-Besse personnel in that they continued to believe CRDM flange leakage was a cause of CAC and radiation monitor fouling. Had this been understood by the licensee, increased efforts could have been taken by the licensee in 12RFO to identify the source(s) of RCS leakage.

Other inspections which dealt with the RCS or RCS leakage indications provided the NRC with additional opportunities to engage the licensee on their efforts to resolve RCS leakage. Two inspections (NRC reports Nos. 50-346/99-002 and 01-004) reviewed radiological controls for containment entries to clean the CACs. In 1999 the inspector observed one of the work crews in containment while the CACs were cleaned and discussed the boric acid deposits on the CACs from a pressurizer isolation valve. Both inspections assessed the radiological implications for CAC cleaning but did not assess the implications of the CAC fouling, i.e.,continued RCS leakage or Davis-Besse's efforts to resolve the leakage.

Two inspections (NRC report Nos. 50-346/98-006 and 00-005) reviewed inservice inspections (ISI) related to the RCS. They were performed during the 1998 and 2000 refueling outages. The 1998 inspection observed a dye penetrant examination of a CRD housing weld and a visual examination of the reactor vessel bolt holes The report did not mention boric acid on the head or any related issues. In an interview, the inspector did not recall seeing boric acid on the reactor head or on the insulation directly below the CRDM housings. During the 2000 ISI inspection, the inspector observed ultrasonic and magnetic particle examinations on the reactor closure head to flange weld. In addition the inspector reviewed CR 2000-0781 and verified the corrective actions were appropriate. This CR described boric acid on the reactor head which prevented the visual inspection of the flange fasteners. There was no discussion in the inspection report on boric acid corrective actions for the reactor head. In an interview, the inspector who performed the 2000 ISI inspection did not recall seeing boric acid on the reactor head or anything unusual about the corrective actions for CR 2000-0781. The general guidance of IP 73753, Inservice Inspections states, "Personnel performing this inspection should also be observant about the general condition of the plant. While traveling to and from the ISI examination sites, the inspector should be looking for evidence of boric acid leakage, rust and water stains, and other indications of deterioration of fluid boundaries. All indications should be noted and explored by questioning the licensee about evaluation and corrective actions for items noted." The team concluded these inspections were additional examples for the NRC to become informed of the boric acid accumulation of the reactor head and question Davis-Besse on their corrective actions.
During interviews, RIII personnel stated that at the time the RCS leakage in containment was not viewed as a significant safety issue. Factors that RIII provided to support a basis for this

view included RCS leak rates being less than the TS limit and Davis-Besse providing logical explanations as to possible sources of leakage. The team noted other items which confirmed this view by RIII. These included the lack of guidance to the residents inspectors for pursuing the leakage under the inspection program; the lack of senior management's awareness of the continuing nature of the RCS leakage in containment, not performing any followup inspection in 12RFO on licensee efforts to identify and correct RCS leakage (even though a 1999 NRC inspection recognized that the source of corrosion particles in containment was unknown and reviews would be performed in 12RFO); not recommending that the PI&R inspection in February 2001 review RCS leakage corrective actions (see Section 3.3.2); a briefing paper to support a Regional Administrator's site visit in March 2001 which stated there were currently no significant equipment concerns, but later mentioned monthly CAC cleaning; and an April 2001 Commissioner briefing package which did not list/ discuss continued RCS leakage in containment.

As noted in Section 3.3.2 the senior resident inspector was aware that boric acid was discovered on the reactor head in 12 RFO. The discovery of red/ brown boric acid on the reactor head was a significant insight that the numerous and longstanding indications of RCS leakage in containment were important safety concerns that demanded NRC followup. Since this information was not passed onto the region, the opportunity for the region to factor the discovery of boric acid on the reactor head into their view on RCS leakage in containment was lost. The team believes the ability to assess relevant conditions into the overall outlook on plants issues is an extremely important function of the inspection staff. This function is even more crucial for resident inspectors who are the only NRC individuals that have access to all this type of information.

3.3.1.2 Recommendations

3.3.1.2.1 Recommendations for NRC

- Re-emphasize questioning attitude among NRC staff/management. Consider this attribute in individual and organizational performance measures.
- In refresher training discuss the Davis-Besse head degradation event and highlight symptoms that were available to the NRC staff during inspection activities
- Establish structure and expectations for management interaction with staff to followup on the types of problems that occurred at Davis-Besse
- ***Review inspection procedure Attachment 71111. 20, Refueling and Outage Activities, to determine if adequate instructions and expectations for outage reviews are specified.*** MAYBE MOVE
- Emphasize to inspectors the need remain aware of their surroundings when inspecting in a particular area, such as radiation protection, and the need to pass on observations to applicable personnel

3.3.2 The NRC Failed to Adequately Inspect the Safety Performance of the Davis-Besse Nuclear Power Station

For those issues that were inspected or the NRC had some knowledge of, no significant deficiencies were identified by the NRC even though many of the licensee actions were superficial, lacked appropriate engineering rigor, were not followed through, or were symptomatic in nature. For example, the licensee had no recent documented safety evaluation of the fouling of the safety-related CAC's, but apparently relied on a 1992 evaluation of CAC fouling, which assumed the post-loss of coolant accident (LOCA) environment in the containment would, in effect, steam clean the CAC's so that they would remain functional in a post-LOCA environment. For a time, the licensee used a kerosene burner inside containment to heat the water for the power washer used to clean the CAC's during power operations. Routine, at-power cleaning of the CAC's was known by NRC, and actually witnessed in at least one case. There was no documented fire hazards analysis of this activity. On a number of occasions, the containment radiation monitors were restored to operable status shortly after filter change out even though the monitors were still in saturation. Before a late 1999 Technical Specification amendment, approved by the NRC, the applicable Technical Specification allowed outage time was only 6 hours. No NRC inspections revealed deficiencies in this area. The explanation that the source of CAC fouling stemmed from the leakage past the pressurizer safety valve seats following the temporary modification to the tail piping was accepted by the NRC staff without questioning. The resident inspectors did not follow-up on the licensee's plans to look for the source of the RCS leaks during the spring 2000 refueling outage. Had they done so, they would have questioned if a plan was ever developed and that only routine containment walkdown were actually .

3.3.2.1 Detailed Discussion

The team identified shortcomings with the NRC inspection effort at Davis-Besse. These included missed inspection opportunities that related to the reactor head degradation, inaccurate inspection results, and improper implementation of the inspection program. The team reviewed inspections that were implemented under both the former NRC Inspection Manual Chapter (IMC) 2515, Reactor Inspection Program - Operations Phase, and the revised reactor oversight process (ROP).

Prior to April 2000, inspections at operating reactors were preformed under the guidance of an earlier revision to IMC 2515. The majority of inspections performed under 2515 were part of the "core" program which was implemented at all reactor sites. The regions had allowances to perform "regional initiative" inspections in areas with identified or perceived licensee performance problems. In April 2000, the NRC transferred to the ROP which is more structured than the former IMC 2515 program. Under the ROP, baseline (BL) inspections are performed at all reactor sites and they constitute a larger portion of the overall inspection effort. The ROP has supplemental inspections which are performed for problems (findings) that have greater than low safety significance. The ROP does not allow "regional initiative" inspections of lower level problems or issues that potentially could, but have not yet resulted in a significant problem. The team reviewed inspections implementation at Davis-Besse back to 1990s but focused on inspection activities since 1996, which correlates with the estimated time that head degradation began.

As discussed in Section 3.3.1, five reports from 1999 documented inspections related to RCS leakage. The report writeups for these inspections have limited information on inspector actions. Most of the writeups contain phrases such as, "the inspectors reviewed the licensee's efforts .." and "the inspectors reviewed licensee efforts..." but provided no other indications of specific actions that the inspectors performed. Interviews with the applicable inspectors provided no additional insights on the depth of these inspections. Based on review of Davis-Besse records and interviews with Davis-Besse personnel, the team identified several relevant issues that could have been identified by a probing inspection. These included an apparent lack of operability limits for CAC plenum pressure or current justification that boric acid fouling would not effect CAC post accident function (Davis-Besse responded to the team that steam from a LOCA would clean boric acid from the CACs was not supported by engineering calculations); no evaluation to support the use of a kerosene heater in containment for CAC cleaning; and the temporary modification that changed the pressurizer discharge piping configuration which stated that boric acid corrosion of carbon steel components was not a concern but provided no basis to support this view.

While reviewing Davis-Besse's efforts to identify the source of RCS leakage in containment the team noted that an action plan was not developed for 12RFO. Based on limited information that Davis-Besse was able to locate for this effort, it appeared that only routine outage inspections were performed to identify RCS leakage in containment This was contrary to a corrective action specified in CR 99-1300 to issue an action plan for containment walkdowns in 12RFO to identify the source of the red/ brown boric acid deposits on the containment radiation monitor filters. For the following refueling outage,13RFO, the Mode 3 containment walkdown was not performed at the beginning of the outage. The Mode 3 walkdowns were initiated in response to GL 88-05 as a means to identify containment leakage with systems at normal operating pressure and temperature. As noted in Section 3.3 1, following the 1999 inspections there were no NRC documented inspections of the Davis-Besse efforts to identify RCS leakage. Since indications of RCS leakage were continuing, the team concluded probable cause existed to perform additional inspections and that these inspections could have identified problems with Davis-Besse's efforts to identify the source of RCS leakage in containment.

Davis-Besse's corrective action program was last inspected under the 2515 core program in August 1998 per Inspection Procedure (IP) 40500, Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems. This inspection did not review any issues related to RCS leakage in containment or boric acid on the reactor head. Based on the timing of this inspection and the limited information available on these topics, the team considered this was not unexpected. The frequency of performing IP 40500 inspections under the core program was every SALP cycle, which for Davis-Besse was every two years. The next review of corrective action program was the Problem Identification and Resolution (PI&R) inspection in February 2001. This was performed under the ROP which initially required a PI&R inspection each assessment period. The first ROP assessment period was from April 2000 to March 2001. Based on the timing of the PI&R, there was a 2 ½ year gap between these corrective action inspections. In light of the ROP expectation to perform a PI&R inspection each year, the team questioned the decision to perform the Davis-Besse PI&R inspection at the end of the ROP assessment cycle verses earlier. This would have allowed a more timely review of Davis-Besse's corrective action implementation and possible recognition that efforts to locate and correct RCS leakage in containment were inadequate.

The team identified two aspects of the 2001 PI&R inspection that warrant further discussion. Guidance for PI&R inspections is provided by IP 71152, Identification and Resolution of Problems. The general guidance section of IP 71152, states, "Additional insights for determining appropriate samples can be obtained by region based inspectors through discussion with resident inspectors or regional inspectors who are familiar with site issues and who are familiar with the licensee's problem identification and resolution process " Routinely the DRP branch chief will provide insights to the PI&R team on problem areas that the PI&R may consider for followup review. Based on interviews with the 2001 PI&R team members and the branch chief, there were no suggestions to review any of the ongoing symptoms or CRs related to RCS leakage in containment or boric acid on the reactor head. In the interview, the branch chief stated that he did not consider the RCS leakage in containment significant enough to warrant followup by the PI&R inspection. The team determined the continuous nature of the RCS leakage and the ineffective licensee corrective actions were types of situations that IP 71152 intended for PI&R followup and that RIII should have suggested this to the team.

In determining which problems to review for corrective action implementation, the PI&R team screened previous CRs. For the Davis-Besse PI&R this was accomplished by reviewing a printout containing abbreviated CR descriptions. For CR 2000-0782 the abbreviated description was, "Inspection of the Reactor Flange indicated Boric Acid leakage from the weep holes." As noted below, the actual condition description for CR 2000-0782 contained a substantial amount of information on the type, quantity, and location of the boric acid. IP 71152 does not specify the manner in which licensee identified problems are select for PI&R review, e g., review entire problem descriptions verses an abbreviated description. With the large number of CR written by many licensees, reading each CR description may not be practical during a PI&R inspection. However, the team believes that had the complete description been used in the screening of issues, CR 2000-0782 should have been selected for PI&R review.

On August 6, 1999, escalated enforcement was taken for boric acid corrosion on 3 of 8 body-to-bonnet nuts for Pressurizer Spray Valve, RC-2 at Davis-Besse. The Severity Level III violation was for inadequate material control, carbon steel nuts were installed in lieu of stainless steal nuts, and for failure to implement effective corrective action. A special inspection (Report No. 50-346/99-021) of this event reviewed corrective actions, both taken and planned, for the RC-2 event. Enhancements to the boric acid corrosion procedure, NG-EN-00324, were discussed in the report. LER 1998-009-00 describe this event and two corrective action commitments that Davis-Besse made to the NRC. These included enhancements to the boric acid control program and training for managers and technical staff on boric acid corrosion control and lessons learned from the RC-2 event. The team noted some members of the technical staff who were involved with previous and subsequent boric acid corrosion issues did not receive the training. Also, some weaknesses in revised procedure, NG-EN-00324 were observed. The team noted that RIII did not perform a followup inspection to closeout the violation for RC-2. There were followup inspections for the LER and Revision 1 to the LER; however, they did not specifically address a review of the completed corrective actions. IP 92902, Followup - Maintenance, which was in effect at the time for closeout of maintenance related violations required that licensee's implementation of corrective actions be reviewed. For the RC-2 violation it is unclear if the NRC actually inspected/ reviewed corrective action implementation. In interviews with RIII managers, differing views were provided on the closeout of RC-2 violations. Some managers thought that closeout of LERs and the review performed in the special inspection were satisfactory, while other managers believed that a violation closeout should include a review of corrective action implementation. The team concluded that the guidance for closeout of violation was not followed and an additional inspection of Davis-Besse's boric acid corrosion program would have provided an opportunity to identify some of the program weaknesses.

IP 62001, Boric Acid Corrosion Prevention Program, was included in Appendix B to the former IMC 2515 program which listed regional initiative inspection procedures. RIII did not use IP

62001 in the followup inspection to the RC-2 event. Based on the circumstances surrounding RC-2 and the fact that a special inspection was performed, the team believed that IP 62001 should have been utilized to provide structured guidance for the inspection. While it was not clear that use of IP 62001 would have altered the conclusions of the special inspection on the boric acid corrosion program, it would have ensure that the review included all critical aspects of the program

The senior resident inspector stated in an interview he was aware that boric acid was identified on the reactor during the 2000 refueling outage (12RFO) but recalled that the condition was not viewed as significant at the time and he believed the problem didn't warrant NRC followup inspection. Also the senior resident inspector stated that he had reviewed the licensee's boric acid corrosion program following the RC-2 event and believed that boric acid on the reactor head would be properly resolved based on his favorable review of Davis-Besse's boric acid corrosion program. The senior resident inspector's recollection of the condition was white boric acid crystals on the head with no indication that the quantity of boric acid was large. CR 2000-0782 documented the boric acid that was discovered on the head in 12RFO. The condition description stated, "Inspection of the Reactor Flange indicated Boric Acid leakage from the weep holes (see attached pictures and inspection record). The leakage is red/brown in color. The leakage is worse on the east side weep holes. The worst leakage from one of the weep holes is approximately 1.5 inches thick on the side of the head and pooled on top of the flange... The total estimated quantity of leakage though the weep holes and resting on the flange is 15 gallons. All leakage appears to be dry. Preliminary inspection of the head through the weep holes indicates clumps of Boric Acid are present on the east and south sides..." CR 2000-1037 was subsequently written to disposition the boric acid on the reactor head. Its description stated, "Inspection of the Reactor head indicated accumulation of boron in the area of the CRD nozzle penetrations through the head. Boron accumulation was also discovered on the top of the thermal insulation under the CRD flanges. Boron accumulated on the top of the thermal insulation resulted from CRD flange leakage." Based on the senior resident inspector's recollection of the condition of boric acid on the reactor head it is unclear if the CR descriptions were actually read. Under the ROP, Appendix D, Plant Status, to IMC 2515 provides guidance for problem identification with the statement, "Review the licensee's deficiency or non-compliance reports to became aware of safety significant problems that can be followed up through elements of the baseline program". The team concluded that the description of CR 2000-0782 should have been viewed as a potential safety significant problem and received follow up by the baseline program. Additionally, the pictures attached to CR 2000-0782 provided a graphic view of the significance of the boric acid deposits. Since the information regarding boric acid discovered on the reactor head in 12RFO was not passed on to the region, there not an opportunity for the region to consider the need for follow up inspection.

The team identified a positive aspect of RIII's ROP implementation, in the utilization of baseline inspections to review important commitments associated with Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles." These commitments were implemented to support Davis-Besse's continued operation to February 16, 2002 (see Section 3._._). RIII mapped out the commitments to various baseline inspection activities, then completed the reviews during routine 6-week inspections. The inspection results were documented in NRC Inspection Report Nos. 50-346/01-015 and 01-016.

3.3.2.2 Recommendations

3.3.2.2.1 Recommendations for NRC

- Assess the overall PI&R guidance such that issues similar to those experienced at Davis-Besse are reviews (possible emphasis on the 3 -6 issues /years PI&R inspections and the biannual inspections). Determine if guidance is needed on the format of issues that are screened when to determining which specific problems will be reviewed.

- Review ROP guidance to determine if changes are needed to allow longer term followup on issues that haven't progressed to a finding. Should IFIs be allowed that would direct future inspections in areas of concern

- Emphasize through a "case study" training that inspection must probe into issues or potential problems verses reviewing licensee action and providing a status of these action in an inspection report

- Assess the need for inspection of licensees boric acid corrosion programs, similar to the actions directed by IP62001.

- Consider various method to independently assess plant performance, then compare and contrast the results with existing plant performance assessment performed by the region.

3.3.3 The NRC's Performance Assessment of Davis-Besse Nuclear Power Station Was Not Accurate and Failed to Fully Integrate Available Performance Data

There were widespread views within the NRC that the DBNPS was a strong safety performer, and their corrective action program was regarded as one of the best in the region. While the NRC had considerable information regarding the symptoms of the problem, there was never any focused inspection effort to ascertain its true nature. Some NRC staff believed that the individual symptoms were not significant enough to perform inspection follow-up. Other NRC managers and staff believed, without serious challenging or questioning, that the licensee was adequately pursuing the problems. Clearly the NRC did not consider the continuing nature of the RCS leak in containment and the effects of boric acid corrosion on carbon steel components.

3.3.3.1 Detailed Discussion

The NRC viewed Davis-Besse as a good performer prior to discovery of the reactor head degradation in February 2002. This view was shared by nearly all RIII interviewees, the NRR Project Managers and resident inspectors. The ROP inspection results and performance indicators (PI) also support this view in that all PIs and inspection report findings since ROP implementation had been Green. The last Systematic Assessment of Licensee Performance (SALP) was for the period of January 22 1995, to January 18,1997. The SALP scores were a "2" in Operations and a "1" in the remaining three areas, Maintenance, Engineering and Plant

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Support. The team leader for the 2001 PI&R inspection stated in an interview that DBNPS's corrective action program was viewed as one of the best in the region.

For the 3-year period between the last SALP assessment and ROP implementation in April 2000, the plant performance review (PPR) process was used to assess Davis-Besse's performance. The team reviewed all the PPR summaries for this period and identified only one discussion point involving RCS leakage in containment or its symptoms. For the PPR review that ended on January 31, 1999, the "Material Condition" section of the summary mentioned that unidentified leakage was more than half the allowed value and CACs need to be cleaned on a regular basis due to boric acid buildup. No future inspections were recommended in the PPR to address this area. In the letter to Davis-Besse, dated March 26, 1999, which transmitted the PPR results, there was no mention of RCS leakage, CAC cleaning or assessment of the licensee's corresponding actions. The team concluded that the PPRs conducted from February 1997 to March 2000 failed to adequately assess Davis-Besse's performance and take appropriate regulatory responses. Numerous plants problems related to RCS leakage in containment were known by the NRC and documented in inspection reports but were not recognized for their safety implications.

Under the ROP, assessments of plant performance are performed on a somewhat informal basis every quarter and in a structured manner every 6-months. The team reviewed the summary packages for the assessments performed through December 2001. There was no mention of RCS leakage in containment, the accompanying symptoms, or boric acid on the reactor head. The ROP assessment process reviews problems (designated as "findings" by the ROP) that have a significance of Green or greater. Findings are classifies by the significance determination process (SDP) with the lowest rating being Green, very low safety significance. Under the ROP the NRC identified numerous Green findings at Davis-Besse but none dealt with RCS leakage in containment or boric acid corrosion control. The ROP assessment process also reviews performance indicators (PIs) that licensees report to the NRC. For PIs that rise above the Green band, the NRC will engage the problem with additional inspections and regulatory interface. The PI that monitors RCS leakage was relevant to the performance issues experienced at Davis-Besse. The Green threshold for this PI is one half the TS limit for RCS allowable leakage. For Davis-Besse this value is one half GPM for unidentified RCS leakage, which was not exceeded while the ROP was in place. A noteworthy observation is that this PI would have been White in 1999 when RCS unidentified leakage reached a value of 0.8 GPM. The NRC response under the ROP would have been a supplement inspection to review the corrective actions for the root cause(s) of the condition. The NRC's assessment of Davis-Besse's performance was in accordance with the ROP guidance and was based on the findings and PIs that were available. As noted earlier, the team believes that performance issues existed at Davis-Besse which could have been characterized as finding and then could assessed by the ROP.

As noted in Section 3.3.2 the senior resident inspector was aware that boric acid was discovered on the reactor head in 12 RFO, however, this information was not provided to the region. The senior resident inspector did not followup on this condition. During the interview with the resident inspector, he stated that he was not aware that boric acid was discovered on the reactor head in 12RFO. An expectation for resident inspectors is that important issues are discussed between the residents to capitalize on group dynamic interaction and utilize the entire resident staff knowledge level when performing their initial assessment. Since the resident inspector was not aware of this information this interchange must not have occurred. The team recognizes that resident inspectors must sort through many issues that licensees enter into their corrective program and then decided on which issues to followup on based on their importance and potential to impact plant safety. However, the team viewed the discovery of red/ brown boric acid on the reactor head following numerous and longstanding indications of RCS leakage in containment as one of the most crucial pieces of information that could have led to an earlier identification of reactor head degradation. With the senior resident inspector not following up on this issue, this opportunity was lost and not passing the information onto the region prevented RIII from understanding its significance.

When reviewing why the senior resident inspector did not followup on boric acid on the RPV, the team noted that the ROP was initially implemented while 12RFO was ongoing. In interviews, the resident inspectors mentioned that additional effort was required to understand and plan for the ROP. The team's own experience with ROP implementation supported this factor and that some of the resident's time which previously would have been used for inspections was required for ROP startup.

The unreliability of RCS leakage detection containment radiation monitoring system due to fouling with boric acid, iron oxide, and water and Davis-Besse's numerous actions to live with condition verse resolve the root case was an example of the NRC not fully integrating all available information into its assessment. Data that was available to the NRC included.

- Several unintentional entries into 6 hour TS shutdown action statements due to both trains being inoperable at the same time.

- In May 1999, the systems were becoming inoperable so frequently due to filter clogging, that each train was to be removed from service every other day, on a staggered basis, to replace the filter as a pre-emptive measure. However, some low flow alarms still occurred.

- Many Channel 3 detector (iodine) saturation alarms occurred that required filter changeouts. It was unclear from a review of the operator logs whether Channel 3 was still in saturation after the filter was changed out and the system declared operable.

- In July 1999 and April 2001 the sample points were changed from the primary location (at the top of D-rings) to the alternate location (dome or personnel hatch). While this reduced the frequency of filter changeouts, it may have also made the detection system less efficient at detecting leaks.

- In August 1999 a temporary modification installed four portable HEPA filtration units in the containment in an attempt to remove the particles that were clogging the filters. This activity was documented in NRC Inspection Report No. 50-346/99-010 which stated the HEPA units were installed to remove the corrosion product particulates in the containment atmosphere that periodically affected the operation of the radiation monitors.

- In November 1999, the laboratory analysis of the material clogging the filters identified the presence of ferric oxide. Specifically, this analysis stated, "The fineness of the iron oxide (assumed to be ferric oxide) particulate would indicate it probably was formed from a very small steam leak." The iron oxide particles that were clogging the filters was discussed in NRC Inspection Report No. 50-346/99-008.

- A temporary modification was installed in January 2001 to bypass the iodine sample cartridge because of frequent fouling This temporary modification was inspected and documented in NRC Inspection Report No. 50-346/01-013.

As noted in Section 3.3.1, many levels of the NRC were aware of the problems and actions that Davis-Besse took when dealing with filter clogging. This occurred over an approximate 3-year time period. Based on interviews with involved individuals and review of applicable inspection reports, the team concluded that the NRC failed to properly assess the large quantity of available data and identify the inadequate actions taken by Davis-Besse.

An example of the NRC not properly integrating inspection insights involved an issue discussed in NRC Inspection Report No. 50-346/98-018. The report describes a letdown cooler isolation valve, MU-1A, that was found with a packing leak during an online containment search for RCS leakage in December 1998. This occurred shortly after RC-2 packing leak which corroded three of eight body-to-bonnet fasteners (see Section 3.3.2) Following questioning by the NRC inspector on the initial MU-1A work scope that did not include insulation removal to check for boric acid corrosion, the work was modified to include insulation removal. When the insulation was removed a body-to-bonnet leak that encompassed about 270 degrees of the seating area was discovered. Subsequent repairs corrected the leaks. The inspection report characterized Davis-Besse's performance in a positive manner for their efforts to minimize the leak. The report's conclusion and executive summary did not capture the limited initial corrective action and that NRC prompting was required to ensure adequate corrective actions were implemented. While the inspectors recognized the previous problem with RC-2 and factored that into their inspection activity, the NRC failed to integrate similar performance problems into its regulatory assessment for this issue. Highlighting additional implementation deficiencies with the boric acid corrosion program would have provided greater emphasis to thoroughly improve the program.

Following discovery of the reactor vessel head wastage at Davis-Besse, headquarters and regional staffs considered whether to send an IIT, an AIT, or an SIT to the site per the guidance in Management Directive (MD) 8.3, NRC Incident Investigation Program. According to interviews with staff and managers, the LLTF learned that the decision was strongly influenced by risk assessment. In order to develop a risk estimate, an initiating event frequency of 0.1 was assumed, which resulted in a CDF of 1E-5, which was right between the AIT and IIT criteria. This initiating event frequency of 0.1 was chosen as a compromised between 1 (which would have applied had there been a LOCA) and 0.01, which was the assumed initiating event frequency for failure of a CRDM tube due to circumferential cracking. The LLTF found that there did not appear to be a solid technical basis for choosing this event frequency, nor did there appear to be explicit treatment of pressure boundary degradation in PRAs. These observations highlight the uncertainty of some risk information and question if risk should be used in these types of regulatory decisions.

3.3.3.2 Recommendations

3.3.3.2.1 Recommendations for NRC

- Determine if additional guidance is needed to pursue issues and problems identified during plant status reviews and if other improvement to plant status guidance is needed. Of particular important is management's engagement/ recognition of issues and the guidance that is given to the inspection staff

- Re-emphasize questioning attitude among NRC staff/management. Consider this attribute in individual and organizational performance measures.

- Review ROP assessment process to determine if changes are needed to identify plants that may have similar problems as Davis-Besse, however, the inspections results has only Green findings and Green PIs

- Determine if other plants, which were only assessed by PPRs for a similar length of time as Davis-Besse, have problems that need to be addressed

- Improvement to the Barrier PIs should be considered

- Management Directive 8.3 should be reviewed for possible over-reliance on risk determination that have too much uncertainty

3.3.4 The NRC Failed to Adequately Communicate Critical Information Regarding the Safety Performance of the Davis-Besse Nuclear Power Station

The former senior resident inspector was aware that boric acid deposits were found on the RPV head at the start of the spring 2000 refueling outage and performed a cursory screening review of at least one of the three corrective action documents (condition reports) that noted this, but he did not inform his supervisor, nor did he perform any focused inspections or review any of the RPV head inspection videotapes. Consequently, none of the regional staff were aware that significant boric acid deposits were found on the RPV head at the start of the outage. The symptoms of the prolonged RCS leaks were routinely discussed by the former senior resident inspector and his supervisor, but no direction was provided by the supervisor to conduct follow-up reviews. The supervisor discussed these symptoms regularly from the beginning of 1999 through 2001 during the Region III daily plant status meeting, which is routinely attended by senior managers, but no managers had a detailed recollection of these discussions. Attendance at daily plant status calls with the resident inspector staff and supervisor by NRR project managers assigned to DBNPS was inconsistent. The project manager's recollection of the discussions on RCS leakage symptoms was mixed. No members of the NRC staff interviewed by the task group recalled any discussion or consideration that the of RCS leakage in the containment could be RCS pressure boundary leakage. This was influenced by their knowledge of potential sources of the leakage, such as flange, relief valve discharge, or valve packing leaks.

3.3.4.1 Detailed Discussion

The organizational structure of the NRC regional offices with respect to oversight of operating nuclear power reactor facilities consists of a Division of Reactor Projects, which provides management of the resident inspector program, and a Division of Reactor Safety, which provides oversight of the region-based specialist inspection staff. The senior manager directors of each division report to the Regional Administrator, who has overall responsibility for implementation of the regional office mission. The NRC Office of NRR, Division of Licensing Project Management, is responsible for the project management staff and is the principal interface between the regional office and NRC headquarters staff.

The task group interviewed several NRC managers and staff from NRR and Region III, including the former senior resident inspector. The task group also observed conduct of routine daily plant status calls and meetings in the Region III office. Information on plant status, reportable events, and other operational issues was communicated by the resident inspector office staff to the Division of Reactor Projects supervisor during daily plant status calls. The supervisor responsible for the DBNPS also had oversight responsibility for the Clinton Nuclear Power Station and Perry Nuclear Power Station and a common daily plant status call was conducted for the three facilities. NRR project managers typically participated in these status calls to be informed of plant status, but from interviews with past project managers, the task group found that this had not been a consistently implemented practice. Following these daily plant status call with the supervisor, a regional office daily staff meeting was conducted. Attendance at the daily staff meeting included the regional office first-line supervisors, regional duty officer, division managers, and the regional administrator. NRC headquarters staff and managers participated by telephone conference. The daily staff meeting provided a forum for the duty officer to present reportable events since the last meeting and for each of the Division of Reactor Projects supervisors to present plant status and operational items of interest. The meeting also provided an opportunity for the supervisors to inform the Division of Reactor Safety supervisors and managers of technical issues that may require the support of regional specialist inspectors for resolution.

The task group noted that the regional office procedure for conduct of the daily staff meeting had not been revised since 1994 and did not provide guidance for the content of the meeting as it was presently conducted. From interviews with inspection staff, the former Division of Reactor Projects supervisor, and some NRR project managers, symptoms of RCS leakage were well known. RCS unidentified leak rate, CAC fouling and cleaning, and RCS leakage detection radiation monitor system fouling and filter changes were all communicated during daily plant status calls during the 1999 through 2001 time frame. These activities were communicated during daily staff meetings attended by senior managers, but senior managers interviewed either did not recall these discussions or remembered few specific details. Interviews with the task group indicated that the daily plant status calls with the supervisor focused primarily on activities associated with the Clinton Nuclear Power Station, which was operating under an Inspection Manual Chapter 0350 oversight program.

The following were examples of RCS leakage symptoms being communicated but that actual extent of condition was not accurately described nor was it fully understood by the recipient:

- CAC cleaning and RCS leakage detection radiation monitor system issues were documented in several inspection reports. However, NRC senior managers did not engage the licensee aggressively to ensure that the root causes were understood and corrective actions to address the root causes, versus the symptoms, were planned and implemented.

- A 1999 PPR summary package briefly mentioned unidentified RCS leakage was more than half the allowed value and that CAC cleaning was performed on a regular basis due to boric acid buildup. There was no recognition of this condition as an issue that needed NRC attention. In interview with the NRC staff, the task group was informed that PPR meetings focused extensively on plants that were the subject of additional regulatory oversight and that plants that were perceived as good performers received substantially less discussion of performance issues

- A plant status briefing paper for the regional administrator's visit to DBNPS in March 2001 stated that no significant equipment concerns existed but also mentioned that CAC cleaning were performed on a monthly basis. This item was not considered by the regional administrator as an area of emphasis for his visit.

Other opportunities were missed for communication of RCS leakage symptoms. Some of these included:

- A briefing package was developed for a NRC Commissioner visit to DBNPS in April 2001. The continuing nature of the containment RCS leakage in containment was not discussed in the "Current Issues" section of the package.

- The former senior resident inspector informed the task group that he had been aware of the Condition Report initiated in the 2000 refueling outage that identified boric acid on the RPV head. However, he did not perform any specific followup inspection activities of the issue or inform his supervisor of the condition.

Interviews with region-based inspection staff indicated there was mixed guidance on the documentation and communication of inspection observations. The transition to the Reactor Oversight Process (ROP) resulted in a significant change in the documentation threshold of inspection observations from the previous inspection process and communication of inspection observations to licensee and NRC managers. Some of the staff believed that because observations were no longer documented in inspection reports unless they resulted in a finding using the new significance determination process, the reports no longer provided a historical reference to document trends of declining licensee performance. Additionally, senior manager expectations for providing debriefings of inspection findings and observations at the conclusion of inspections were perceived by the staff to be unclear. Debriefings of inspection observations and findings were perceived by the staff to be of low value and not a priority for senior management. Debriefings of resident inspector staff observations and findings were not performed at the conclusion of their inspections for regional office senior managers or Division of Reactor Safety supervisors.

Informal mechanisms for communicating inspection observations to NRC management or to licensees at inspection debriefings were perceived to be ineffective. Internal communications to senior managers regarding performance were haphazard and external debriefings with licensee δη

managers were perceived as ineffective if no enforcement consequence resulted. The significance determination process was also perceived to be cumbersome and a hindrance to communication of plant performance issues. Unless an item directly affected operability of a structure, system, or component, and the finding fit in to an SDP worksheet, the issue was likely to be lost as being considered below the documentation threshold.

The task group concluded that improvements in the conduct of daily plant staff meetings could be made to help ensure that licensee performance was adequately discussed and that senior managers were more thoroughly aware of plant performance issues. The task group concluded that debriefings of inspection findings at the conclusion of region-based inspections to senior managers could be improved so that findings were adequately understood by senior management. Additionally, the inspection findings of the resident inspector staff could be better communicated to regional managers so that cross-discipline insights could be shared which could improve the assessment process and planning for future inspections.

As discussed in Section 3.3.1, the NRC project manager during 1999 was aware of symptoms of RCS leakage and licensee efforts to determine the source. NRR management did not recall the symptoms of RCS leakage discussed during morning status calls. The perception of the licensee's performance and of the safety posture at DBNPS was generally favorable among NRR staff and management. Thus, the information indicating a degraded condition at DBNPS was available to NRR, but it was not widely disseminated and NRR staff presumed that the regional staff were following licensee efforts to address the problems and did not question the situation.

The Project Manager Handbook discusses the need to maintain communications between the NRR project manager and the resident inspectors on site. The guidance also directs project managers to provide highlights of significant information or events to management. However, there is no specific guidance in the Handbook regarding participation in the daily plant status calls nor the transfer of routine plant status information from those calls. Project Manager participation in daily plant status calls with the regional Division of Reactor Projects supervisor is a management expectation in the NRR Division of Licensing Project Management (they are specifically mentioned in the FY 2002 Operating Plan planning template for project management), but participation appears to be emphasized to varying degrees among the project managers. Also, the task group was aware that conduct of these daily plant status calls was not uniform among the regional offices.

3.3.4.2 Recommendations

3.3.4.2.1 Recommendations for NRC

- Develop and implement guidance for conduct and content of daily plant status calls between the resident inspector office staff, NRR project manager, and regional office supervisor.

- Review and implement guidance for NRR project managers to maintain cognizance of plant operational issues and provide feedback to regional office staff of licensing issues that have licensee performance insights.

- Revise regional procedures for conduct and content of daily staff meetings. Guidance should include provision for senior manager acknowledgment of issues presented and assignment of action items as necessary.

- Develop uniform guidance for inspection debriefings with regional management Guidance should include provision for discussion of plant performance observations that may be indicative of licensee problem identification and resolution deficiencies and declining plant performance.

- Review guidance for the conduct of counterpart meetings between NRC headquarters and regional office staff to determine if additional forums for communication are required of plant performance issues.

3.3.5 Adequate NRC Resources Were not Provided to the Oversight of the Davis-Besse Nuclear Power Station

Regional oversight staffing, experience, and resource issues presented significant challenges in the effective oversight of DBNPS. Because DBNPS was viewed as a good performer, allocation of resources for oversight of DBNPS was not priority, given the number of plants with recognized areas of greater concern. During the period that RCS leakage symptoms were becoming evident, there were unfilled vacancies for resident and region-based inspector positions for significant periods of time. Some of the staff assigned to DBNPS had little or no previous commercial PWR system knowledge or experience. The regional branch that had oversight responsibility for DBNPS also had oversight responsibility for another plant that was in an extended shutdown for safety performance issues In 1999, the total amount of inspection hours expended at DBNPS was approximately 1400 hours for the entire year, while the regional average for other single units sites for that year was approximately 2400 hours. Regional senior managers visited DBNPS much less frequently than other plants. Some senior managers had not been to the site for several years preceding the event. In general, there were limited entries by the NRC staff into the DBNPS containment.

3.3.5.1 Detailed Discussion

The inspection and oversight resources provided to Davis-Besse were minimal during much of the time period that RCS leakage in a containment, its symptoms and identification of boric acid on the reactor head were taking place. As discussed previously, there were many indications which suggested that inspections and NRC interaction with Davis-Besse should have increased. Prior to the ROP implementation, the inspection and assessment process allowed for increased attention, however, the ROP the program did not have this flexibility, given the inspection and PI results for Davis-Besse. As discussed here, the term resources does not apply only to numbers of individuals but also to the experience and training given to these individuals.

Regional staffing for positions associated with Davis-Besse had several lapses in the late 1990s when the normal staffing compliment was not maintained. For this time period, the regional staffing plan for the DRP branch that oversaw Davis-Besse was a branch chief, a senior project engineer, a senior resident inspector and a resident inspector. The branch chief for Davis-Besse was assigned to the branch in October 1997 and remained in that position until May 2001. This provided continuity within the regional office for the oversight of Davis-Besse. The senior project engineer slot was vacant from June 1997 until June 1998 (except for a one month period) and from September 1999 until May 2000. During the initial senior project engineer vacancy the branch chief was also responsible for oversight of the Clinton Nuclear Power Station. This required a significant amount of the branch chief's time because Clinton had been shutdown since September 1996 and its oversight was under the IMC 0350, Oversight of Operating Reactor Facilities in an Extended Shutdown as a Result of Significant Performance Problems, process. Also during the two senior project engineer vacancy periods, Davis-Besse conducted the 1998 and 2000 refueling outages. The team concluded the periods of project engineer vacancies severely impact the branch's oversight of DBNPS during times when the branch chief was busy with other plants, when many of the symptoms of RCS leakage were occurring, and during refueling outages when inspection of Davis-Besse activities was crucial.

For the approximate one-year period from November 1998 to October 1999, there was only one resident inspector at Davis-Besse. This resulted from the senior resident inspector transferring to another site and the selection process for the new senior resident inspector having some delays. Initially RIII planned to assign an individual to the Davis-Besse senior resident inspector position, however, when this did not materialize, the senior resident inspector position was opened to the competitive selection process. The Davis-Besse resident inspector was selected for the senior resident inspector position which then required the resident inspector position to be filled. During this period, some inspectors from the region and other sites assisted the single resident inspector. Also during this period, the resident inspector was involved with the RC-2 event. This included being the single inspector for the special inspection of RC-2 event and assisting the region in escalated enforcement related activities for RC-2. Assigning another inspector to preform the special inspection of RC-2 would have not only allowed the resident to spend more time on other plant issues but would have also allowed another NRC inspector to assess Davis-Besse's corrective action for RC-2.

The annual number of RIII inspection hours for Davis-Besse was below the RIII average for single unit sites for eight of nine years during the period from 1993 to 2001. Of particular noteworthiness is year 1999 in which Davis-Besse had 1422 hours compared to the region's single site annual average of 2558 hours This coincides with the approximate one year period when there was only one resident at Davis-Besse. Also there was not a PE assigned to Davis-Besse for the last 3 months of 1999. Based on the SALP scores and the PPR assessment results it was not unexpected that Davis-Besse received fewer hours that other RIII single unit sites. During 1999 when the site only received 1422 inspection hours, CAC and radiation monitor clogging increased dramatically and the midcycle outage occurred. The region's ability to follow up on the problems that were occurring at this time was limited by inspection resources applied to Davis-Besse.

There was a high turnover rate for NRR project managers with responsibility for Davis-Besse. From 1989 to 2002, nine project managers were assigned to Davis-Besse. Interviews with several of the project managers currently employed by the NRC, indicated that project managers trips to sites occur infrequently or not at all. The Project manager handbook, Section 2.4.2, Interactions with the Regional Office, contains guidance on interactions with the resident inspector, including recommended frequent of trips to the site. Clearly the guidance which

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suggested quarterly site visits was not met, but more importantly is the view in the handbook that the project manager and resident inspectors for an operating reactor share the responsibility for assessing safe operation of their assigned nuclear power plant, therefore, the project manager and resident inspectors must develop and maintain a strong and effective working relationship. Given the large turnover rate for project managers and their infrequent site visits, the team questioned if this expectation was satisfied.

Site visits to Davis-Besse by RIII senior management in the last half of the 1990s were somewhat limited. Travel and site dosimetry records indicate that no senior managers visited the site in 1998. Also, for the period from July 1999 to February 2002, no DRP senior managers visited Davis-Besse. This did not follows the guidance in IMC 0102, Oversight and Objectivity of Inspectors and Examiners at Reactor Facilities. Paragraph 04.05 (b) of IMC 0102 states that DRP division directors or deputy should make every effort to visit each site at least once every two years. The earlier revision to IMC 0102, which was in effect for the time period being discussed, stated that DRP division director or deputy visits should occur each SALP cycle, which for Davis-Besse had been 24 months. In should noted that during this period the regional administrator and the DRS deputy division director each visited Davis-Besse twice.

For the time period that RCS leakage in containment, its symptoms, and identification of boric acid on the reactor head were taking place at Davis-Besse, RIII had several plants in extended shutdowns and/or where starting up under the IMC 0350 process. These plants included Clinton (shutdown in September 1996 and the 0350 panel disbanded in September 1999), D.C. Cook (both units shutdown in September 1997 and the 0350 panel disbanded in June 2001) and LaSalle (both units shutdown in September 1996 and the 0350 panel disbanded in _____). In response to this, RIII management distributed available resources to plants with the perceived needs. Since Davis-Besse was viewed as a good performer, the application of minimal resources to Davis-Besse was a conscious decision. The team acknowledged that the prioritization of inspection needs verses inspection resources has occurred in all regions to some degree. The structure of the ROP allows less shifting of resources since the baseline inspection program is more prescriptive than the old "core" program when specifying the minimal amount of in inspection activities that must be accomplished at each site.

Neither the current resident inspector nor the former senior resident inspector (who was the resident inspector when first assigned to Davis-Besse) were fully qualified when they went to Davis-Besse. Not being a qualified inspector when assigned to a resident inspector position distracts from the site's overall inspection effort in that the non-qualified inspector could only inspect limited areas (only areas they may be interim certified) and the senior resident inspector must spend time training the resident inspector. Senior managers in RIII acknowledged that resident inspector have been placed at sites prior to become a qualified inspector, however, this choice was made in lieu of the alternate of having longer periods of resident inspector vacancies at sites. In interviews, senior management noted a higher than average staff turnover rate and greater difficulties in recruiting as compared to the other regions as reasons for some of the longer than desired vacancies.

Experience is important factor that directly affects an inspector's ability to identify significant issues or those issues having potential safety significance. This comes into play when inspectors are screening issues that licensees enter into their corrective action program. The assignment to Davis-Besse was the first commercial nuclear power plant experience for both the resident inspector and the former senior resident inspector. Providing training to inspectors is an effective means to supplemental areas where the inspector's experience is limited. All the inspectors who were questioned in interviews regarding boric acid corrosion stated they had not received training in this area. IMC 1245, Inspector Qualification Program For the Office of Nuclear Reactor Regulation Inspection Program, provided the programmatic requirements for the training and certification of NRC inspectors involved with reactor oversight. Neither the version of IMC 1245 that was previously in effect not the revised (date April 2002) version provided any training on boric acid corrosion.

An additional measurement of resources provided for DBNPS oversight would be the number of plant tours/ inspections in the plant. For the RPV degradation event, the most relevant indication would containment entries by NRC staff. In 1998 and 2000 the resident inspector and senior resident inspector had a total of seven containment entries during each RFO. Containment entries by NRC management were very infrequent (section 3.4.2 provides additional information on containment entries).

DO WE NEED TO DISCUSS LIMITED MATERIALS EXPERTISES????

3.3.5.2 Recommendations

3.3.5.2.1 Recommendations for NRC

- Enhancements to the NRC inspector training should include: 1) provide training on boric acid corrosion; 2) increasing knowledge level on selected industry operational experience; 3) utilized Davis-Besse reactor head degradation as a case study for inspector initial certification and requalification; and 4) update training at TTC to include event lessons learned.

- Re-enforce expectation of IMC 0102 regarding regional management visits to reactor sites

- Conduct an assessment of staff needs in the materials area

- Establish measurements for resident inspector staffing and consider establishing nationwide expectations to satisfy minimum staffing

- Consider 0350 impact on regional branch assignment of facilities and the need for program guidance on distribution of oversight function for branch with 0350 plants

- Assessment of maximum turnover rate for NRR project managers (i.e. assignment/reassignment) and update the Project Manager Handbook to be consistent with current management expectation regarding project manager site visits and interaction with regional staff

- Reassess policy for selecting uncertified staff for resident positions

3.3.6 Davis-Besse Failed to Effectively Communicate Information to the NRC Which Adversely Affected NRC Oversight and Assessment Functions

The task force found indications that mis-communications concerning the boric acid deposits on the RPV head existed between the licensee and NRC, and within the licensee's organization. The licensee mis-communications resulted in actual or potential missed opportunities for the NRC to have either identified the VHP nozzle leaks or RPV head degradation. The mis-communications may have also contributed to the ability of the licensee's organization to effectively address the indications preceding the event For example, licensee oral and written communications regarding the status of RPV head cleaning during the spring 2000 refueling outage was inaccurate or incomplete. Some of this information was provided to the NRC. For example, a system engineer, in the spring of 2000, apparently told the resident inspector that the RPV head was completely cleaned. Some licensee staff members knew the head was not completely cleaned, while others did not In April 2001, the licensee made a presentation to an NRC Commissioner during a meeting at the site. One of the presentation slides stated that the reactor vessel head was cleaned and visually inspected during previous outages. One of the condition reports that documented that there were significant boric acid deposits on the head in the spring of 2000 noted that the work performed to clean the RPV head was completed without deviation.

3.3.6.1 Detailed Discussion

Inaccurate Information in Submittals - The licensee submitted responses to NRC BL 2001-01 and to subsequent related NRC requests for additional information that were documented in FENOC letters to the NRC dated September 4, October 17, and October 30, 2001 (2 letters). The task force found many instances of inaccurate information in the licensee's submittals. Significant examples include:

- FENOC stated in the September 4, 2001, submittal (page 3) that "Some boric acid crystals had accumulated on the RPV head insulation beneath the leaking flanges. These deposits were cleaned (vacuumed). After cleaning, the area above the insulation was videotaped for future reference." The task force interviewed the RCS system engineer who indicated that the reactor head insulation area cleaning was planned but never performed, consequently, a video taping of the cleaned insulation head area was also never made.

- In the same submittal, FENOC discussed the April 2000 inspection results (page 3), stating that, "Inspection of the RPV head/nozzles area indicated some accumulation of boric acid deposits. The boric acid deposits were located beneath the leaking flanges with clear evidence of downward flow. No visible evidence of nozzle leakage was detected." The task force reviewed the April 17, 2000, video tape of the RPV head. The video record shows visually and by verbal comments incorporated on the videotape, that the accumulated boric acid deposits were significant, in contrast to the FENOC letter.

- FENOC stated in the September 4, 2001, submittal (page 3) (Subsequent Review of 1998 and 2000 Inspection Videotapes Results) that "Since May 2001, a review of the 1998 and 2000 inspection videotapes of the RPV head has been performed. This review was conducted to re-confirm the indications of boron leakage experienced at the DBNPS were not similar to the indications seen at Oconee Nuclear Station and Arkansas Nuclear One Unit 1; i.e., was not indicative of RPV nozzle leakage. This review determined that indications such as those that would result from RPV head penetration leakage were not evident." The task group attempted to obtain any related report on the tape reviews, and the basis for the determination that RPV head penetration leakage was not evident given that a bare metal head (or nozzle) inspection was never performed. The origin of the brown boric acid was never explained. Consequently, the task group concluded that the FENOC determination was not adequately supported.

- In the same submittal (page 12), FENOC discussed its approach to RPV head inspection results, stating that "The DBNPS performs visual inspections for evidence of leakage by examining the RPV head surface and the CRDM flanges per the requirements of NRC Generic Letter 88-05,..... If pressure boundary leakage is suspected, supplemental examinations of the affected CRDM nozzle will be performed to characterize the integrity of the nozzle." The task group noted PCAQR 96-55 (Boric Acid on RX Vessel Head) initiated on April 21, 1996, that indicated "There could also be corrosion damage within the reactor vessel head penetration due to boric acid corrosion resulting from a through wall crack in the CRDM nozzle." The PCAQR also states that procedure NG-EN-00324 (Boric Acid Corrosion Control) "... may not have been followed to identify the scope of problem." The boric acid build-up around the CRDM/RPV upper head areas was not removed and inspected until after the February 2002 event during 13RFO. The PCAQR conflicts with the licensee's submittal to the NRC.

- In its supplemental response to NRC Bulletin 2001-01 (FENOC letter to the NRC dated October 17, 2001) FENOC states (page 3 of Attachment 1) that "In summary, results from previous inspections of the CRDM nozzle penetrations provide reasonable assurance for the continued safe operation of the DBNPS until the next refueling outage in March 2002." The task force concluded that the CRDM and surrounding area of the RPV head could not be visually inspected due to the large amounts of boric acid build-up. Video tapes indicating a large amount of boric acid on the head and confirming information gained from individuals interviewed did not provided a basis for the licensee's statement

- In its response to the NRC Request for Additional Information Concerning NRC Bulletin 2001-01, FENOC (by letter dated October 30, 2001) stated that "The inspections performed during the 10th, 11th, and 12th refueling outages "... consisted of whole head visual inspection of the RPV head in accordance with the DBNPS Boric Acid Corrosion Control Program pursuant to Generic Letter 88-05, 'Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR plants.'" (Page 1 of Attachment 1 to the letter). The task force noted that the licensee also stated in Condition Report 96-55, that the inspection was neither "whole head" (page 9 indicates that 50 to 60% of the head area was inspected) nor in accordance with procedure NG-EN-00324, Boric Acid Corrosion Control Program (see page 1 and 1a of the CR). The task group concluded that the information contained in the submittal to the NRC was not supported by plant documentation.

- In its supplemental response to Bulletin 2001-01 dated October 30, 2001, FENOC provided pictorial documentation of the visual examinations of the RPV head performed during the 10th, 11th and 12th RFOs. **FENOC requested that the document be withheld from public disclosure pursuant to 10CFR2.790.**

CHECK PORTIONS OF THE FOLLOWING FOR PROPRIETARY INFORMATION

- RPV Head 11RFO Inspection Results shows photographs of nozzle penetrations that were inspected via video. This document indicates that the pictures were clipped from video taken during the Spring of 1998, and indicates that "... a good video inspection was able to be performed for those 50 drives that were not obscured by boron from leaking CRDM flanges. Although much more video can be viewed, these attached pictures are representative of the condition of the drives and the heads. We attempted to capture in still photographs all of the outer most drives since they are the most susceptible to circumferential cracking based upon finite element analysis..." The task force noted that the pictures shown in the submittal to the NRC included approximately 3 of 4 quadrants of the RPV head. The quadrant not shown included those areas where boric acid build-up was present. The task force concluded that the submittal did not accurately indicate the condition of the entire head in that the drives that were downhill from nozzle 3 were not included

- RPV Head 12RFO Inspection Results shows photographs of nozzle penetrations that were inspected via video. These photos were taken from the 2000 Spring outage videotapes. The document states that "These drives were video taped because they had boron deposits in the vicinity of the CRDMs. Completely clean drive penetrations are not depicted here." The task force determined that the pictures depicted in the licensee's submittal include 10 CRDMs located on the "clean side" of the RPV head which includes less than one quadrant of the RPV head. Also, the task group interviewed the RCS system engineer, who indicated that the first few rows of CRDMs (from the upper dome area) were never cleaned following 12 RFO in 2000. The licensee's statements implied that other than the CRDMs shown in the submittal to the NRC, all penetrations are clean. The task group determined that the statements were inaccurate.

The task force review of licensee records associated with the submittals showed that 12-16 licensee staff members and managers reviewed the responses. The task force concluded that the licensee's organization did not effectively ensure the accuracy of some of the information formally submitted to the NRC.

<u>Licensee Internal Communication Deficiencies</u> - The task force determined from internal licensee communications and from interviews of licensee staff that some licensee staff and managers understood that a full visual inspection of the RPV head at each nozzle location had not been conducted in past refueling outages. The task group reviewed electronic mail messages from the licensee's staff (sent during August 2001) indicating that some were aware that the nozzle locations near the top of the RPV head could not be inspected because of the small clearance between the head and the insulation. Despite this knowledge within the licensee's staff, the response to BL 2001-01 submitted to the NRC on September 4, 2001, stated that "a gap exists between the RPV head and the insulation,... and does not impede visual inspection." In response to further questions from the NRC staff regarding the inspection results, the licensee provided more detailed information (e.g., the October 17, 2001, submittal to the NRC) showing that some nozzle locations were not visually inspected.

The task force determined that the level of understanding of RPV head boric acid deposit conditions varied among different levels of the licensee's organization. Interviews conducted by the task force indicated that managers in the licensee's organization and some staff realized the extent of the RPV head that was actually cleaned during RFO12, while lower-level staff members in the licensee's organization were provided information that led them to believe that the head was thoroughly cleaned. The task force found an example of the licensee internal mis-communication in a newsletter update on RFO12 activities issued by the licensee to its staff. The April 29, 2000, issue of the "Outage Insider" newsletter described the RPV head cleaning activities, and stated that "the reactor head was successfully cleaned" and that "this was the first time in Davis-Besse history that the reactor head has been cleaned." The task force concluded that licensee staff reading the newsletter were left with the impression that the RPV head was clean following RFO12 when, in fact, video inspections reviewed by the task force indicate that this was not the case.

The task force also reviewed a licensee's summary of its quality assurance audit associated with RFO12. The audit specifically covered the licensee's boric acid corrosion control practices, and concluded that the boric acid accumulation from the reactor head was cleaned. This conclusion contrasts with the post-cleaning video inspection that showed boric acid deposits remaining on the head. The task group concluded that the incorrect information communicated within the licensee's organization affected general perceptions among personnel of the RPV head condition and affected licensees's processes that should have highlighted deficiencies the licensee's activities associated with maintaining the RPV head condition.

<u>Deficient Licensee Internal Documentation and Communication with NRC Inspectors</u> - Interviews conducted by the task force of NRC and licensee staff and managers showed that differences in understanding existed regarding the information related to the NRC about the condition of the RPV head. Although a previous NRC resident inspector was cognizant of boric acid deposits on the head, he was not aware of the degree of the problem. Some licensee staff thought that the NRC was told in detail about the nature of the boric acid deposits. Also, licensee staff maintained that NRC staff had seen the video taped inspections of the RPV head during discussions related to the licensee's responses to BL 2001-01. NRC staff interviewed by the task force recalled that following a meeting between NRC and licensee staff in 2001, the licensee staged a viewing of some video tapes, but it was unclear to the NRC staff involved the extent of the coverage of the RPV head that was included. The written material reviewed by the task force and interviews of NRC staff supported the view that, before February 2002, the NRC was provided photographic information from video inspections, but not the videos themselves.
The task force did not conclusively determine the total extent of the information that was provided to the NRC inspectors and staff (i.e., written and oral), but the task force found that differences exist between what the licensee thought the NRC knew about boric acid deposits on the RPV head and what the NRC staff actually knew.

The licensee's response to its condition report (CR-00-1037) detailing accumulation of boron on RPV head provided the perspective that all boron had been removed from the head during the cleaning process. If the NRC inspectors had reviewed this CR, they most likely would have concluded that the licensee's actions were appropriate based on its descriptions of the licensee's actions and of the RPV head condition To determine that the RPV head had not been fully cleaned would have required firsthand observation of the cleaning effort, review of the videotape, or that specific information be provided to inspectors by the involved individuals.

The CR description indicated that boron had accumulated in the area of the head control rod drive (CRD) nozzle penetrations and on top of the thermal insulation under the CRD flanges. It also mentioned CR-00-0782, which initially identified boron deposits coming from the weep holes and having a red/brown color. The boron accumulation was worst on the east side of the RPV head, with a thickness of approximately 1.5 inches on the side of the head and pooled on the flange in the area of the studs. The estimated quantity was 15 gallons. Pictures attached

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to CR-00-0782 clearly depicted the condition of the boron accumulation. This condition was identified on April 6, 2000.

The response to CR-00-1037 mentioned NRC generic letter 97-01 with the following wording:

> "... The letter requires licensee to maintain a program for ensuring a timely inspection of the control rod drive mechanism (CRDM) and the vessel closure head penetrations. The program is required due to the degradation of the CRDM nozzles caused by Primary Water Stress Corrosion Cracking process In order to perform required inspections the nozzles as well as the penetrations must be free of boron deposits. Once the head is free from the boron, new boric acid deposits may be easily noted and remedial action taken."

The Remedial Actions section of the CR response stated, "Accumulated boron deposited between the reactor head and the thermal insulation was removed during the cleaning process performed under WO 00-001846-00. No boric acid induced damage to the head surface was noted during the subsequent inspection." In the description of work for WO 00-001846 the statement, "Work performed without deviation", was annotated.

Based on interviews that it conducted of the licensee's staff, the task force understood that all boric acid deposits were not removed from the head during the cleaning efforts in 12RFO. Also, a post-cleaning video inspection reviewed by the task force shows remaining boric acid deposits. The task force found that the response to the CR did not accurately reflect the condition of the RPV head following cleaning activities

In an interview of the former NRC senior resident inspector, the task force found that he had reviewed a CR during 12RFO that described the boric acid deposits on the head *(he was unsure which specific CR that he reviewed).* The SRI stated that he did not provide any follow-up inspection effort to this CR or the condition of BA deposits on the reactor head The task force determined this condition could have been inspected/ followed up under the baseline inspection program which had been initiated at approximately the same time (April 1, 2000). This is discussed further in Section 3. ---- of this report.

Inaccurate Information in Licensee Presentations - The briefing packages for Commissioner Merrifield's April 27, 2001, visit and the December 16, 1998, and March 2, 2001, Management Meetings between Region III and Davis Besse did not mention the continuing problem with RCS leakage in the containment and the resulting buildup of boric acid deposits on CACs and rad monitors. In addition Commissioner Merrifield's briefing package mentions on page 19 that, "Reactor Vessel Head Cleaned/Visually Inspected During Past Refueling Outages" and "No Cracking or Leakage Found." The statement in the briefing package that the reactor head had been cleaned and visually inspected in past RFOs is inconsistent with actual cleaning efforts during past RFOs. There were some levels of licensee management who were aware of this fact, however, the inaccurate information was still provided in the briefing package.

Later presentations made by FENOC to the NRC staff and executives indicated that boric acid deposits remained on the vessel head. FENOC presentations made to the NRC on November 14, 2001, and January 23, 2002, indicated that some CRDM nozzles would be masked by boric acid deposits, thus precluding visual inspection for leakage. Slide 5 in the November 14 presentation (entitled Leakage Detection) indicated that previous "inspections provide reasonable level of assurance for nozzles without masking boron deposits." Slides 4 and 5 in the January 23 presentation specify visual inspection for unobscured nozzles and supplemental NDE inspections for obscured nozzles

3.3.6.2 Recommendations:

3.3.6.2.1 Recommendations for NRC:

- The NRC should take steps (i.e., establish processes and provide resources) to verify information provided by licensees in response to safety-significant generic communications and in support of other safety-related information submitted by licensees.

3.3.6.2.2 Recommendations for Industry:

- The DBNPS event should be used as an example to strongly encourage licensees to provide to the NRC complete and accurate information on plant operations and system conditions.

- The DBNPS licensee should take steps to improve its internal communications to ensure that accurate information on plant operations and system conditions is available throughout the organization. This should include processes to ensure that written records include information consistent with actual system conditions, and that internal audits include steps to verify information about system conditions.

3.3.7 The NRC Failed to Provide or Implement Licensing Process Guidance

The task force noted that in a number of areas related to the licensing process, the NRC either did not provide adequate guidance to the NRC staff, or did not implement existing guidance. NRR licensing project managers interviewed by the task force stated that they infrequently visited the site, if at all, while assigned to DBNPS. The task force found that for DBNPS, the NRR licensing project manager turnover rate was high. In a number of instances, existing licensing process guidance was not being implemented by NRR staff or it was lacking. For example, the licensing project managers had not reviewed the periodic commitment change report submitted by the licensee, contrary to office instructions. Some of these reports involved changes to commitments pertaining to the CAC's. The information submitted in conjunction with a license amendment request related to the containment radiation air monitors was not independently verified, which is inconsistent with staff guidance.
The task force considered some of these deficiencies to be contributing factors to the regulatory posture that allowed the DBNPS event to occur. The other deficiencies are incidental to the problem and were uncovered in the course of the review conducted by the task force. However, the task force made recommendations in each area.

3.3.7:1 Detailed Discussion

Licensing Oversight - NRR staff and management interviewed by the task force held the prevailing view that the licensee was considered a good overall performer before the event in February 2002. Some individuals cited the positive ROP indicators as the basis for this perception, and others added that the plant did not seem to have many licensing problems or "crises" and, therefore did not demand an inordinate proportion of staff resources. In the view of some NRR staff and managers interviewed by the task force, this positive view of the licensee's performance influenced decisions that affected the level of regulatory attention directed to DBNPS. For example, in recent years, there was a higher-than normal turnover rate of licensing project managers assigned to DBNPS. One project manager held the position for several months in 1999, another for about 6 months from 1999 to 2000. For the period from 1990 through 2001, nine different licensing project managers were assigned to DBNPS. The task force noted that guidance for project managers contained in the Operating Reactor Project Manager's Handbook (the PM Handbook) maintained online by NRR does not discuss an expected duration for project manager assignments. However, the guidance stresses the importance of effective working relationships between NRR project managers and Regional staff, especially the site resident inspector. The task force judged that shortened assignment durations for either project managers or resident inspectors would hamper the establishment of effective working relationships.

Also, the most recent project managers (1999-2001) had made no site visits to DBNPS, nor had the NRR/DLPM section chief. Reasons for the lack of visits cited included. for one project manager, that the assignment was too short and did not include a plant shutdown period, which would be the most desirable time to visit; that the plant was a good performer and other more pressing priorities made conducting a visit difficult (such as completing licensing actions to support a planned shutdown); lack of management emphasis for making site visits a priority. The PM Handbook Section 2.4.2, "Interactions with the Regional Office," suggests that project managers make frequent trips to their sites, and stipulates that these should be conducted at least quarterly. This guidance is included in a section that gives steps that should be taken to maintain a close relationship between the project manager and the site resident inspectors. The task force learned that in recent years, NRR management has not emphasized that guidance and has instead focused on the project manager's role in headquarters licensing activities. Some project managers interviewed by the task force associated the change in emphasis on project manager site visits with the revision of the reactor oversight process. The task force found no written guidance contrary to the PM Handbook, however, DLPM managers supported the contention that management emphasis has been weighed toward licensing activities rather than conducting frequent site visits

The task force concluded that an effective working relationship should be encouraged between project managers and site resident inspectors. To this end, the guidance in the PM handbook should be implemented and the need for project managers to visit their sites regularly should be emphasized. Regular visits would have several benefits, including; heightened awareness by project managers of the condition of the plant, provide another set of eyes and ears for licensee oversight (even if not continuous), and enhance the working relationship between the project manager and site resident inspectors that would benefit communications when the project manager is back at headquarters.

<u>License Amendment Review Process</u> - As discussed elsewhere in this report, clogging of the CACs and containment air radiation monitor filters with corrosion products were indications of significant RCS leakage. The task force found 2 license amendments for DBNPS related to this equipment. The first was DBNPS License Amendment Number 180 issued on September 9, 1993, that allowed use of the containment gaseous radiation monitoring system as an alternative means of detecting RCS leakage. The task force judged that the NRC safety evaluation appropriately considered the information available and that the review was documented following NRR guidance. The task force reviewed the safety evaluation and

related documentation (e.g., the licensee's submittal, the FSAR, and TS bases) to determine if adequate background information was available to operators to use filter change frequency as an indicator of an RCS integrity problem. The filter change frequency was not discussed.

The second was License Amendment Number 234 that included a change for containment radiation monitors (RCS leakage detection systems) and was issued on November 16, 1999. The LAR proposed changing the operability requirements for the containment air radiation monitors. The LAR contained no information to imply that there was a material condition problem with the containment air rad monitors. The LAR was part of a larger request to move some technical specifications (TS) systems to the technical requirements manual (TRM) and for the RCS leakage detection TS to reflect the Babcock & Wilcox Improved Technical Specifications (ITS), NUREG 1430. The LAR was a straightforward request to implement NRC guidance for removal of systems from the TS to the TRM or implementation of line-item TS improvements to match the B&W ITS. Minimal NRR technical review was conducted.

The change allowed by the amendment resulted in essentially 1 of 4 monitors (gas or particulate) required to be operable and eliminated the 6-hour shutdown action statement (not TS Section 3.0.3) that existed previously. The amendment resulted in only requiring one radiation monitor to be operable instead of requiring both operable, as was previously specified. The task force noted that there are 2 sets (trains/skids) of containment air radiation monitors, each set has gas, particulate, and iodine (iodine is not mentioned in SAR nor TS). Each train shares a common containment air flowpath. Removing one train from service removes all 3 monitors from service.

The safety evaluation for the license amendment was prepared by the NRC project manager for DBNPS and received the concurrence of managers in three technical branches (EEIB, EMCB, SPLB). The justification for the change made to the RCS leakage detection system included the capability of the remaining operable systems and compensatory measures to detect RCS leakage when one of the required systems became inoperable. The Safety Evaluation also considered that the change was consistent with NUREG-1430, "Standard Technical Specifications - Babcock and Wilcox Plants." There was no discussion in the evaluation of the current state of the system or its operating environment.

Although not stated in the LAR, the task force determined that this submittal was made during a period when frequent filter changeouts were required. Iron oxide was found in the filters during this period and HEPA filters were installed in containment. The task force judged that if the NRR review had included steps to verify the actual condition of the system, the operability problems would have been considered and may have led the staff to question the viability of the proposed change. In this case, the staff's review did not include a step to verify actual system conditions. The task force concluded that this could have been done by either requesting the information from the licensee or by using information available to the NRC resident inspectors at DBNPS.

The task force found that the SER content conformed with the guidance in LIC-101, License Amendment Review Procedures." Although the Office Instruction directs the project manager to solicit input from resident inspectors to verify information by the licensee, the nature of the submittal would not be expected to prompt the project manager to verify information. However, the task force noted guidance in the PM Handbook (section 2.4) that discusses expected project manager interactions with resident inspectors and visits to the site. One objective of the guidance is that the licensing project manager be familiar with all aspects of plant operating status. This guidance states:

> "Communication with the RO through the RI and the appropriate projects branch in the RO should be established and maintained. The PM should arrange to visit the RI at the site periodically to become better acquainted with the plant, its systems and special features, and its staff in association with the RI. To the maximum extent possible, these visits should also be used to perform field observations and verifications of licensing matters under review by the PM.
> It is of paramount importance that the PM and RI thoroughly understand each others functions and remain knowledgeable of current issues in which each is involved To achieve this understanding, the PM should use telephone calls and accompany the RI or other region-based specialists in conducting portions of inspections during the PMs site visits (see Section 5.1.7, Participation in Regional Inspections), and to become familiar with the plant."

If this guidance was adhered to for DBNPS, the licensing project manager may well have been aware of the containment air monitoring system operability problems when the licensee's proposed change was submitted. Conversely, the RI would have been aware of the licensee's requested change and may have questioned the basis, given the system operability problems and indications of chronic RCS leakage.

The task force concluded that the PM Handbook guidance should be emphasized to help ensure more complete consideration of plant information in licensing actions. Moreover, NRR should generally encourage a questioning attitude among project managers. Although the regional staff should remain the focal point for ensuring the day-to-day safe operation of the plants, NRR shares a responsibility for plant oversight, and project managers and their supervisors should be encouraged to question information regarding plant operation and conditions.

<u>Decision to Defer Shutdown</u> - The basis for the NRC decision to allow DBNPS to delay shutdown past December 31, 2001, was reached without a well documented NRC analysis of the information available. The December 4, 2001, letter from the NRC to FENOC allowed plant operation past the date specified in BL 2001-01 based on information submitted by FENOC in November 2001. It stated that the staff's decision was based on information provided by the licensee and information available to the staff regarding industry experience with VHP nozzle cracking. The letter also mentioned that the licensee's commitments made to support its proposal for continued operation were integral to the staff's finding. However, the letter does not discuss what specific information from the licensee or from industry was considered, nor is the underlying analysis of the information by the staff discussed. The task force found that the letter does not provide the basis for the staff decision in sufficient detail to determine what independent evaluation or verification was conducted by the staff.

Interviews of NRC staff conducted by the task force indicated that NRR management took steps to ascertain the range of staff views regarding the basis to allow DBNPS to continue operating past December 31, 2001. After considering information presented by the licensee during the November 30, 2001, meeting, the staff caucused and individuals were polled on their views. The overall view was that, based on the information available, the plant could continue operating past December 31, 2001, for a short period. A few staff members did not agree with that conclusion.

The December 4 letter contrasts with the detailed basis provided in the proposed order to shutdown DBNPS and DC Cook (a November 11, 2001, memo to the Commission forwarded the proposed orders for information). The proposed order cited inspection results at facilities with similar susceptibility ratings as DBNPS and large uncertainties in the cracking mechanism and extent of cracking at the plants. Staff assumed that RCPBs could be compromised at the subject plants, and therefore required their shutdown.

The lack of a detailed basis or technical information to support the staff's decision documented in the December 4, 2001, letter contrasts with processes and guidance applied to other safety-related decisions taken by the NRC. For instance, the guidance in LIC-101 for preparing safety evaluations to support routine license amendment requests specifies the format of the NRC safety evaluation and the expected content of each section in sufficient detail to allow the public to understand the basis for the NRC determination. The staff could have used LIC-101 as guidance since the document itself states that "the guidance should be applied, where appropriate to the processing of.... other licensee requests requiring prior NRC approval." The task force judged that the December 4, 2001, letter did not adequately document the basis for the staff's decision and that an appropriate model to use to improve its content could be the safety evaluation approach offered by LIC-101.

The lack of sufficient background to the decision in the December 4, 2001, does not support the agency's performance goal of increasing public confidence in the NRC's mission. Without a documented basis for the decision, public questions may result regarding the basis for the staff's decision. The task force concluded that procedures should be established to ensure that decisions to allow deviations from agency guidelines and recommendations issued in generic communications are adequately documented.

A clearly applicable procedure was not in place to guide the staff and management though the decision making process nor to suggest that the basis for the decision be documented. Given the large amount of information provided by the licensee, the complexities involved with conducting a risk analysis based on a material failure model, and the short time between new information being submitted to the NRC and the NRC issuing its decision, the task force concluded that although NRR management acted appropriately in making its determination, clearer guidance addressing such situations would help ensure that appropriate decisions are made and that the bases for the decisions are well documented.

A significant part of the licensee's argument for continued operation was based on risk assessments. Based on several interviews of NRC staff conducted by the task force and review of background information related to the licensee's proposal to continue operating, the task force found that the staff was faced with considering a significant amount of information in the risk assessment that included a considerable level of uncertainty. Also, there was not a long period of time available to consider the information. The large uncertainties involved suggest that risk modeling of the degradation of passive components may not be appropriate. Some staff expressed the opinion that the focus on conducting risk analyses is distracting the staff from effective and timely regulatory actions. Other staff expressed the opinion that the NRC has become risk-based as opposed to risk-informed, that issues cannot be pursued without having a risk number attached to them, and that deterministic safety requirements have been discounted. The task group consensus is that these misgivings associated with risk-informed regulation of nuclear power plants need to be addressed by the agency to ensure successful implementation of NRC objectives in this area.

Industry Topical Report Review Process - As discussed in Section 3.4 of this report, the task force found that some of the guidance issued by industry groups that was related to boric acid corrosion control contained deficiencies that may have contributed to deficiencies apparent in the boric acid corrosion control program at DBNPS. An example reviewed by the task force is the EPRI Boric Acid Guidebook.

The review of industry generic topical reports is a licensing function carried out by NRR. Topical reports are technical reports on specific safety-related subjects submitted by industry organizations that may be reviewed independently of a specific licensing review. Guidance for topical report review is given in LIC-500, "Processing Requests for Reviews of Topical Reports." The objective of the topical report review process is to improve efficiency by allowing the staff to review a methodology or proposal that will be used in multiple licensing actions. The guidance in LIC-500 includes criteria for accepting a topical report for review. One criterion is that the report is expected to be referenced in a number of license amendments or other licensing actions. LIC-500 allows exceptions to these criteria, but justification must be supplied by the applicant. The LIC-500 guidance does not explicitly discuss a process for NRC to initiate reviews of industry reports that are not submitted. For example, the EPRI Boric Acid Guidebook was not submitted by EPRI, but it provides generic guidelines to PWRs that may not have been considered acceptable by NRC staff. An NRC review of the Guidebook may have resulted in correction of misleading information and improvements in the BAC program at DBNPS.

LIC-100, "Control of Licensing Bases for Operating Reactors" also discusses the same criteria for staff review of topical reports as does LIC-500. This guidance reiterates that topical reports are reviewed only in support of licensing or anticipated licensing actions.

COM-204, "Interfacing with Owners Groups, Vendors and NEI," includes guidance on certain submitals from vendors and owners groups. It discusses submitals made for information only, where a formal NRC review is not requested. In these cases, the guidance allows for a cursory NRC review to determine if the submital conflicts with NRC rules, regulations or policies. The results of this review do not constitute NRC acceptance or agreement with the material, but allows the staff the opportunity to inform the applicant of any discrepancies found. The BAC Guidebook was not submitted for information to the NRC, therefore, the staff did not present any position on its content. However, such a cursory review may have been sufficient for the staff to highlight deficiencies in the guidance.

The task force concluded that if the staff had reviewed the EPRI BAC Guidebook, it may well have highlighted deficiencies in the industry approach to BAC control that could have been corrected long before the DBNPS event developed. Therefore, the task group determined that the NRC should consider revising current topical report review guidance to allow staff review of unsolicited industry reports.

Regulatory Commitment Tracking - Regulatory commitments are documented actions voluntarily agreed to by licensees that, together with applicable regulatory requirements, form the licensing basis for the plant. Many of these commitments are provided in docketed correspondence such as licensee event reports and responses to generic communications. Regulatory commitments are relevant to the DBNPS situation because, historically, a significant number of commitments at DBNPS were related to boric acid corrosion control, including measures taken to institute a boric acid control program in response to Generic Letter 88-05.

NRR guidance for managing licensee commitments to NRC is contained in Office Letter-900, "Managing Commitments made by Licensees to the NRC," and in the PM Handbook. The office letter references NEI 99-04, "Guidelines for Managing NRC Commitment Changes," stating that it provides acceptable guidance for controlling regulatory commitments The NEI guidance directs licensees to submit a periodic report to the NRC of changes to commitments. Additional NRR guidance regarding licensee commitments to NRC is in LIC-100, "Control of Licensing Bases for Operating Reactors." Table 4 in LIC-100, entitled "Regulatory Commitments," discusses NRC Verification and Monitoring:

> "The NRC inspection program may review a regulatory commitment associated with a particular issue or technical area. In general, however, the inspection program does not assess how well licensees control regulatory commitments. NRR plans to assess the licensees' commitment management programs and their implementation of those programs. This activity will be performed under the DLPM responsibilities for "Other Licensing Tasks."

The task force noted that the NEI guide expressly deals with changes to regulatory commitments. It does not seem to be applicable to overall management of the commitment tracking process nor is it necessarily applicable to all outstanding commitments.

From NEI 99-04:

> "The guidance applies to commitments communicated to the NRC under the current regulatory structure. Licensees must decide how they will address commitments communicated to the NRC prior to the promulgation of the guidance document" in 1999.

The office letter directs project managers to audit the licensee's commitment management program. The PM Handbook does not reference the office letter, mention the audit requirement, nor does it provide guidance for review or disposition of the periodic commitment change report submitted by licensees. NRR project managers contacted by the task force were not aware of the requirement, and the most recent project managers for DBNPS had not conducted an audit.

FENOC letter to NRC dated November 15, 2000, provided the periodic Commitment Change Summary Report to the NRC. It contained 2 items on the CACs, which exhibited frequent clogging during plant operation, indicating a leak in the RCS. Commitment nos. 014438 and 007319 were related to CAC air flow. The Davis-Besse project managers did not recall reviewing the report. The task force determined that the commitments were not related to the clogging from corrosion deposits. However, without NRC staff review of the report when it was submitted, changes to licensee commitments could go unnoticed by the staff.

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The NRC resident inspectors documented problems discovered by the licensee in the D-B commitment management program (Inspection Report 98011, September. 9. 1998). Problems documented were; the licensee's commitment database not clearly summarizing commitments, undocumented justification for deviations from commitments, and changes made to implementation documents with sufficient basis. The inspection team concluded that the corrective action plan was sufficient to address the issue. There appears to be no further NRC follow up on the issue. An audit of the licensee's program by the project manager may have highlighted similar deficiencies and led to steps to improve the licensee's tracking program.

Review of the Periodic Inservice Inspection Report - In accordance with requirements of the ASME Boiler and Pressure Vessel Code, licensees submit inservice inspection (ISI) summary reports to the NRC after significant inspection, repair and replacement activities are conducted. Reports are typically submitted following refueling outages. The ISI Summary report for DBNPS dated August 22, 2000, provided the results of the ISI activities related to the 12th cycle and 12RFO. Page 20 of the report lists control rod drive nozzle to closure head weld visual inspection results for several control rod drive locations The task force reviewed the information in the report, finding that only peripheral control rod drive nozzle locations were inspected. However, this appears to be within the ASME requirement for the percentage of components to be inspected during an outage. **ASK PAT TO VERIFY** The task force noted that some of the nozzle locations inspected were included in an area of the head that was covered with boric acid deposits at the beginning of RFO12. However, the photographs and video tapes depicting the condition of these locations at the periphery of the head showed that these areas were cleaned and the task force concluded that effective inspections could be done at those nozzle locations

Based on interviews and discussions conducted by the task force with NRC staff, the task force found that the NRC rarely reviews the information submitted in ISI summary reports. Based on interviews of NRC staff, the report for DBNPS was not reviewed NRC staff did not see value in NRC review of the reports. The task force found no specific guidance for review of the reports The task force concluded that the staff should determine whether the reports should be submitted to the NRC, and revise the ASME submittal requirement, or staff guidance regarding disposition of the reports, as appropriate.

MAY DROP THE FOLLOWING

The task force determined that during RFO 12, the licensee may not have conducted the ISI inspection of the CRD nozzles in accordance with ASME code requirements. The task force reviewed the licensee's report to the NRC of the inservice inspection results from RFO 12. The report, dated August 22, 2000, indicates that some control rod drive nozzles were inspected and found acceptable under ASME VT-2 visual inspection criteria. The nozzles inspected were all located on the periphery of the RPV head and included nozzles numbered 52, 58, 63, and 64 (the task force was informed by the licensee - via the NRC project manager for DBNPS - that the last 2 digits in the control rod drive assembly designation indicate the nozzle). The ASME code and DBNPS procedure require that a specific percentage of the nozzles be inspected each outage, and that ...... **Requested licensee to provide ISI procedure used for this inspection**

An NRC staff review of the ISI summary report at the time it was submitted may have highlighted this point and led the staff to determine the nature of the RPV head condition. The task force considered this a justification for the staff to consider institutionalizing a review process for the ISI summary reports.

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3.3.7.2 Recommendations

3.7.7.2.1 Recommendations for NRC

- Implement guidance in the PM handbook for project manager site visits and coordination between project managers and resident inspectors. NRR should take steps to foster working relationships between project managers and site resident inspectors. One step is for NRR to better manage project manager assignments to avoid the type of high turnover associated with DBNPS. NRR should consider holding periodic NRR/Regional Office counterpart meetings (including the resident inspectors) to maintain.working relationships among staff and managers in the organizations and to allow exchanges on significant topics.
- Licensing project managers and their supervisors should be encouraged to question information regarding plant operation and conditions. NRR should consider strengthening the guidance related to the license amendment review process to emphasize the need to consider actual system conditions in the safety evaluation. Further, further clear guidance is needed to ensure independent verification of information provided by licensees related to significant licensing decisions.
- NRC should establish procedures to ensure that decisions to allow deviations from agency guidelines and recommendations issued in generic communications are adequately documented.
- NRC should assess the use of risk methods and provide clearer guidance for integration of results into decision-making related to short-notice licensing actions. Clearer guidance addressing such situations would help ensure that appropriate decisions are made and that the bases for the decisions are well documented.
- NRC should revise the guidelines for review of industry topical reports to allow for staff review of safety-significant reports independent of their formal submittal to the NRC. NRC should also provide sufficient resources to support the reviews.
- NRR should either fully implement LIC-900, "Commitment Management Process" or consider revising the guidance if it determines that the project manager audit of licensees programs is not required. Further, the staff should consider the usefulness of the periodic report on commitment changes made by licensees, and if they are not to be reviewed, inform licensees that they do not need to be submitted.
- NRR should determine whether ISI summary reports should be submitted to the NRC, and revise the ASME submittal requirement, or staff guidance regarding disposition of the reports, as appropriate.

3.7.7.2.2 Recommendations for Industry

None

3.4 The NRC and Industry Failed to Establish Adequate Requirements and Guidance for Addressing Alloy 600 Nozzle Cracking and Boric Acid Corrosion of Carbon Steel Components

The task group found that one of the contributing causes of the DBNPS event was that neither the NRC nor industry established adequate requirements and guidance for addressing VHP nozzle cracking and boric acid corrosion of carbon steel components. This is a cross-cutting conclusion that transcends all three other contributing causes. The task group determined that:

- The NRC failed to provide adequate requirements for the inspection of RCS components for leakage and degradation from boric acid accumulation.
- The NRC failed to provide adequate guidance to NRC staff to effectively implement the reactor oversight process.
- The industry failed to provide adequate requirements for detecting and correcting Alloy 600 nozzle cracking and corrosion from boric acid accumulation.

3.4.1 The NRC Failed to Provide Adequate Requirements

3.4.1.1 Detailed Discussion

The Task force reviewed applicable regulatory requirements, including Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, 10 CFR Part 50.55a, and Davis-Besse technical specifications. The team found that these requirements were not sufficient to direct the licensee to identify and resolve VHP nozzle leaks.

The Code of Federal Regulations require compliance with the ASME Boiler and Pressure Vessel Code (10 CFR 50.55a). The ASME Code, however, does not require the non-visual examination of VHP nozzles The ASME Code does not require the removal of RPV head insulation to conduct visual inspections of the RPV head. More than any other single issue, the DBNPS event could be directly attributed to inadequate inspection guidance. These issues have already been recognized by the NRC staff, and actions were already being taken to address them. The enforcement of more general requirements involving RCPB leakage has also been problematic. While the GDC's proscribe RCPB leakage, they do not appear to be enforceable and the existing enforcement guidance is outdated. The enforcement history pertaining to RCPB leakage and Alloy 600 nozzle leakage appears inconsistent. The task force attributed this to: 1) inappropriate licensee interpretations of plant Technical Specifications in which RCPB leakage found while the plant is shutdown is not reported the NRC as a Technical Specification violation because a licensee could not definitively determine when the leak started while the plant was operating; 2) the view by the NRC staff that such leaks are bound to occur through no fault of the licensee but are typically isolated in nature, which has undoubtedly resulted in undocumented enforcement discretion; and 3) no definitive enforcement guidance in this area. Additionally, the NRC had not consistently enforced violations resulting from pressure boundary leakage, nor had the staff effectively maintained corporate knowledge of enforcement regarding vessel head corrosion in 1987. In conducting its review, the task force found inconsistent levels of understanding of the scope and applicability of Code requirements among staff and management responsible for nuclear power plant oversight.
ASME Code and Regulatory Requirements - Requirements for in-service inspection (ISI) are

contained in 10 CFR 50.55a and plant technical specifications at section 4.0.5. Both of these reference Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. DBNPS was committed to the ISI requirements of the 1986 edition of the code from September 21, 1990, through September 20, 2000, since then, the licensee has been committed to the 1995 Edition through the 1996 Addenda.

Per the requirements of Table IWB-2500-1 of Section XI, and the licensee's ISI plan, the licensee is required to conduct an RCS leakage test at nominal operating pressure prior to plant startup following each reactor refueling outage. IWA 5241 requires a direct visual examination, known as a VT-2, of the accessible external exposed surfaces of pressure retaining components for evidence of leakage from non-insulated components. Regarding insulated components (at Davis-Besse, the RPV head), IWA-5242 states that VT-2 may be conducted without removing insulation by examining the accessible and exposed surface and joints of the insulation. When doing such examinations, the surrounding area shall be examined for evidence of leakage. Discoloration or residue on surfaces examined shall be given particular attention to detect evidence of boric acid accumulations from borated reactor coolant leakage. Corrective measures are specified in article IWA-5250, which requires leakage sources of boric acid residues, and areas of general corrosion, to be located. IWA-5250(b) also requires that components with areas of general corrosion that reduce the wall thickness by more than 10% shall be evaluated to determine whether the component may be acceptable for continued service, or whether repair or replacement is required.

The code does not require non-visual examinations, such as surface or volumetric NDE of VHP nozzles as a means to identify and characterize cracks in those nozzles.

In September 2001 (roughly concurrent with the review of licensee responses to Bulletin 2001-01), NRC staff members who serve on ASME code committees wrote to ASME and proposed that the inspection requirements be changed to VT-2 examination of 100% of the reactor vessel head surface or under the head NDE capable of detecting and sizing cracking. ASME is considering changes to the inspection requirements, but has yet to implement revisions.

The Code requirements for mechanical joints (e.g., CRDM flanges at DBNPS) in the RCS differ from those for welded joints. Provided that the licensee performs an assessment of any leakage from mechanical joints, and the leakage volume is within technical specification limits, it is permissible for plants to start up from refueling outages with known leakage from mechanical joints. The Task Force found that the licensee's practice of operating with known CRDM flange leaks helped to mask the VHP leakage. The Task Force concluded that the looseness in the applicable ASME Code requirements, i.e., the ability to analyze, rather than fix, known RCS leakage, enabled the licensee to tolerate leakage on the RPV head.

As discussed in Section 3.1 of this report, there have been several cases of through-wall cracking of VHP nozzles. In fact, the licensee for Arkansas Nuclear One has concluded that a through wall cracking of VHP nozzles to be a statistical certainty. In the case of Davis-Besse, the Task force determined that the lack of a requirement in the ASME code to remove the vessel head insulation during system pressure tests contributed to the missed opportunities for early identification of nozzle leakage and resulting corrosion of the vessel head. Also, the failure to conduct periodic volumetric NDE on the nozzles prevented the licensee from detecting cracks before they progressed to the point of leakage. This is because that even under ideal conditions, a visual examination is incapable of determining the extent of cracking It is only capable of determining that cracking has advanced sufficiently to allow RCPB leakage.

Enforcement of RCPB Leakage Requirements - Plant technical specifications typically prohibit operation with known pressure boundary leakage. Therefore, relying on boric acid residues to show that through wall nozzle leakage has occurred is a lagging indicator. In cases where pressure boundary leakage has occurred, the NRC's responses have been inconsistent over the years. Based on staff interviews and document reviews, the task force found a range of agency responses, from no action taken in the case of Arkansas Nuclear One, to the granting of enforcement discretion in the cases of VC Summer and Oconee, to taking enforcement action against Palisades and San Onofre. Several factors contributed to this phenomenon, including internal communications, varying licensee interpretations of technical specifications and 10 CFR 50.73 reporting requirements, staff variability regarding the treatment of passive component failures, the **introduction of the ROP,** and lack of enforcement guidance. As of the preparation of this report, the NRC's Office of Enforcement was working with NRR to develop a uniform policy for dealing with pressure boundary leakage.

For example, EA 97-414 involving Inconel Alloy 600 RCS instrument nozzle cracking at SONGS 2 and 3 cited the Maintenance Rule (10 CFR 50.65) because of a lack of staff support to cite against the licensee's Technical Specification for reactor coolant pressure boundary leakage. The violation was cited at a Severity Level IV because there was a lack of unanimity as to whether the violation should have been cited as a Severity Level III violation. During the PEC, the licensee presented information in which they asserted that the NRC and industry have recognized that leakages due to PWSCC are not an immediate safety concern because the staff believes that catastrophic failure of a penetration is extremely unlikely. In reference to the Technical Specification requirement proscribing pressure boundary leakage, the licensee quoted from NUMARC 93-01, 9.3.1, which states: "Entry into a Technical Specification Limiting Condition for Operation, although important, is not necessarily risk significant." The entire licensee argument was focused on the nozzle ejection stemming from catastrophic failure rather than from boric acid wastage. In the case of the event at VC Summer, the licensee did not make a 10 CFR 50.73 report for the underlying technical specification violations associated with operating with RCPB leakage until after enforcement discretion was issued some time following discovery of the problem.

The Task Force discussed with OGC staff the enforceability of the General Design Criteria (GDCs) in Appendix A of 10 CFR Part 50. The GDCs are referenced in licensing documentation and, often, in generic communications. The current OGC advice is that the GDCs are generally not legally enforceable because 10 CFR Part 50.34 requires applicants to address them in their license applications and Preliminary Safety Evaluation Reports. The GDC requirements are then embodied in licenses on plant-specific bases. In order to be able to enforce a GDC at a particular plant, the NRC would have to be able to show: that there is nothing else in a plant's license that would cover the matter in question, and; how adequate protection requirements have not been met by the existing licenses.

Technical Specifications Related to RCPB Leakage - DBNPS technical specification 3.4.6.1 requires the containment sump level and flow monitoring system and one containment atmosphere radioactivity monitor to be operable. The basis for this specification states that these detection systems are consistent with the recommendation of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems." The regulatory position in

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RG 1.45 states, in part, that these systems should be adequate to detect an unidentified leakage rate of 1 gpm in less than one hour.

Regarding the sensitivity of leakage detectors, RG 1.45 states: "Sumps and tanks used to collect unidentified leakage and air cooler condensate should be instrumented to alarm for increases of from 0.5 to 1.0 gpm in the normal flow rates. This sensitivity would provide an acceptable performance for detecting increases in unidentified leakage by this method." Beyond this reference, neither the technical specifications nor the regulatory guide discuss situations in which unidentified leakage increases noticeably from normal steady state values while still remaining below 1 gpm. Additionally, these documents do not contain any requirements for responding to leakage detection system alarms. At DBNPS, leakage detection system alarms occurred, but the licensee's response to them did not lead to identification of the pressure boundary leakage that occurred on the RPV head.

Technical specification 3.4.6.2a specifies that there shall be no RCS pressure boundary leakage. The basis for this specification states: "Pressure boundary leakage of any magnitude is unacceptable since it may be indicative of an impending gross failure of the pressure boundary. Therefore, the presence of any pressure boundary leakage requires the unit to be promptly placed in cold shutdown."

The surveillance requirements for the leakage detection systems require various channel checks, calibrations, and functional tests, as appropriate for the systems and instrumentation involved. The surveillance requirements applicable for pressure boundary leakage include monitoring the containment atmosphere gaseous or particulate radioactivity at least once per 12 hours, monitoring the containment sump level and flow indication at least once per 12 hours, and performance of an RCS water inventory balance at least once per 72 hours during steady state operation.

From 1995 through the middle of 1998, unidentified leakage from the DBNPS RCS averaged about 0.05 gpm every month. In August, 1998, unidentified leakage began to increase steadily, and it was above 0 5 gpm in December, approximately a tenfold increase in four months. This leakage was primarily due to leakage from the pressurizer relief valve, which is discussed elsewhere in this report. Unidentified leakage continued to increase until it exceeded the RCS condition monitoring criterion of 0.75 gpm in April 1999. This criterion had been established by the licensee as part of its response to the Maintenance Rule (10 CFR Part 50.65). After the relief valve was repaired, unidentified leakage ranged from about 0.15 to 0.27 gpm until the plant was shut down for the 12th refueling outage in the Spring of 2000. This amount of leakage was about three to five times as high as the long term average steady state leakage from 1995-1998.

Based on the above, the Task Force concluded that the licensee failed to follow up on reliable indications of increased unidentified leakage. Factors contributing to this failure included: a) the lack of requirements for responding to leakage detection system alarms, and b) the lack of a Maintenance Rule leakage criterion based on deviation from normal, in addition to the single threshold criterion.

<u>Probabilistic Treatment of Passive Components</u> - The treatment of piping within the framework of risk-informed regulation appears to have been a complicating factor in addressing issues with RCS pressure boundary integrity. Based on interviews with knowledgeable NRC staff and

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management, the Task Force learned that the degradation of passive components, specifically, wastage from outside the pressure boundary, has not been explicitly accounted for in PRAs. Although risk estimates of the rapid failure of a pressure boundary are used as inputs into PRA LOCA models, in practice, piping is generally treated deterministically. Deterministic requirements include the GDCs and Sections III and XI of the ASME Code, and these are used in conjunction with available risk information to establish baseline assumptions for PRAs. This factor has led to difficulty among regional, NRR, and OE staffs in characterizing the significance of, and responding accordingly to, instances of pressure boundary leakage.

<u>BL 2001-01 Required Shutdown Date</u> - BL 2001-01 required high susceptibility plants to shutdown by December 31, 2001, and inspect their RPV head penetrations. The task force found through interviews with NRC staff, that the basis for the date was predominantly logistical. It was chosen to give licensees time to allow plants to use the fall outages to information from inspections that could be provided in responses to the NRC. The proposed order to shutdown DBNPS by December 31, 2001, (see memo from Travers to the Commission November 11, 2001) cited inspection results at facilities with similar susceptibility ratings as DBNPS and large uncertainties in the cracking mechanism and extent of cracking at the plants. It also characterized the Oconee circumferential cracking as "potentially risk-significant condition" that could result in gross RCPB failure and LOCA. The proposed order explained that inspecting for leakage was not sufficient to detect extent of nozzle damage. It clearly stated that VT-2 methods do not provide reasonable assurance that leakage from though-wall flaw would be detected. The proposed order also highlighted other shortcomings of the ASME code inspection requirements, i.e., no insulation removal, NDE not required, head cleanliness not addressed.

In considering the proposed rule, the NRC staff surmised that RCPBs could be compromised at DBNPS and DC Cook, therefore the December 31, 2001, shutdown was to be required. The proposed order stated that near term inspections were required due to damage detected in other plants and uncertainties/variability in plant susceptibilities:

> "Operation of facilities considered to be highly susceptible to this cracking phenomenon beyond December 31, 2001, is unacceptable unless the recommended inspections to identify this potentially hazardous condition are completed and found acceptable by the staff."

The proposed order also provided a risk-based argument for the unacceptability of operation past December 31, 2001. The staff cited B&W design-specific information, D-B TS3/4/4/6 for pressure boundary leakage and applied risk-informed decision criteria in RG 1.174 (small in crease in CDF, and that the basis for the licensee's risk estimate could not be verified without inspection).

The licensee submitted additional risk-related information on November 30, 2001, and made several commitments that the NRC considered sufficient to allow continued plant operation (see December 4, 2001, NRC letter to the licensee). However, as stated in Section 3.3.7 of this report, the staff's technical basis was not clearly documented. In interviews with NRC staff, the task force found that the additional information from the licensee affected the perceived risk of the situation and affected the staff's decision. In interviews with the task force, the staff recalled little discussion amongst the staff about the requirement to maintain RCPB leakage integrity. As discussed in Section 3.3.7, some staff members thought that the reliance on a risk analysis in such situations undercut the ability to apply regulatory requirements. The task force concluded that the weaknesses in application of regulatory requirements for RCPB leakage integrity, and the reliance on risk estimates rather than assuring RCPB leakage integrity affected the decision to allow DBNPS to operate past the date in BL 2001-01.

3.4.1.2 Recommendations

3.4.1.2.1 Recommendations for NRC

- The NRC staff should continue to pursue ongoing efforts to encourage the ASME Code requirement changes for inspections of reactor vessel heads, including nozzle penetrations, strengthened (NRR), or as an alternative, pursue changes to 10 CFR 50.55a.
- The NRC should pursue revision of the ASME Code to reduce the ability for plants to start up with known leakage from RCS mechanical joints.
- The NRC should establish a clear enforcement policy for RCS leakage and should not grant enforcement discretion for nozzle cracking
- NRC should review the bases for the 1 gpm unidentified leakage limit to determine if this criterion is adequate to address low levels of leakage from the RCS pressure boundary.
- NRC should review, and revise as necessary, the Maintenance Rule requirements and guidance pertaining to RCS unidentified leakage. The results of this review should address requirements to establish a normal level of unidentified leakage and methods for establishing action levels based on deviations from normal.

3.4.1.2.2 Recommendations for Industry

- Industry should revise related ASME code requirements to address the shortcomings in VHP inspections and reduce the ability for plants to start up with known leakage from RCS mechanical joints.

3.4.2 The NRC Failed to Provide Adequate Reactor Oversight Process Guidance

There is no specific reactor oversight process guidance that would have caused the NRC to focus on the issues associated with this event, particularly in the area of boric acid corrosion control. This transcends the significant changes to the NRC's reactor oversight process that became effective in April 2000. Prior to this time, the NRC had a nonmandatory inspection procedure in the area of boric acid corrosion control that was never used at DBNPS and rarely used at other plants. This procedure and dozens of other inspection procedures, including one that was occasionally used to perform inspection follow-up of NRC generic communications, were canceled in 2001 because of their lack of use during the first year of the revised reactor oversight process. Additionally, neither the previous nor the current inspection program places much emphasis on the inspection of passive components, such as the RPV. The NRC's significance determination process is not well suited to assessing the significance of degraded passive components. Some of the inspector good practices, such as the review of startup mode restraints and containment closeout inspections that were routine prior to April 2000 were not evident after April 2000. Little or no specialized training is provided to the inspection staff on boric acid corrosion control. Some inspectors did not follow up on symptoms of the RPV degradation because they believed the baseline inspection procedure guidance did not specifically address these areas .

The current NRC programs and processes, even if effectively implemented, would not address all the negative safety culture characteristics and attitudes evident at DBNPS. The elements of the NRC's reactor oversight process and other programs (e.g., allegations) involving the cross-cutting areas of human performance, corrective actions, and safety conscious work environment have not been nor would be fully effective in assessing the significant DBNPS safety culture deficiencies in the absence of a significant underlying performance issue such as this. These current tools are extremely limited in scope or have no regulatory teeth. While it is true that the implementation of corrective action inspections did not result in an accurate assessment of the licensee performance in this area, it is not at all clear that meaningful licensee actions would have been taken even if the assessments were accurate absent the identification of a significant issue. The team attributed part of this lack of implementation effectiveness to insufficient guidance. The broader issue, however, is the NRC has no effective means of dealing with a poor safety culture at a plant prior to the onset of serious operational events or conditions. This problem is well recognized, but past actions to address it have not been fully effective. DOES THIS OVERVIEW PARAGRAPH STAY IN THIS SECTION

3.4.2.1 Detailed Discussion

The DBNPS event identified a lack of guidance for assessment and inspection activities that involve alloy 600 nozzle cracking and boric acid corrosion of carbon steel components. Specific areas where the improvements in the guidance are warranted include inspection, enforcement, and significant determination. In addition, the team identified other areas of the ROP that lacked adequate guidance which were not directly related to alloy 600 nozzle cracking and boric acid corrosion of carbon steel components. This section of the report discusses in detail some of the guidance weaknesses and refers to other sections of the report that mentions guidance weaknesses. The intent of this section is to identify all NRC guidance related to the ROP that should be reviewed for areas of improvement. Some of these weaknesses transcended the

ROP and pertained to the guidance that existed prior to ROP implementation in April 2000.

The only specific inspection guidance for boric acid corrosion was provided by IP 62001, Boric Acid Corrosion Prevention Program, which was issued on August 1, 1991, and subsequently canceled on January 17, 2001. The purpose of the IP was to determine if licensee boric acid corrosion control program and its implementation satisfied the requirements of GL 88-05. During IP development, the recommended implementation frequency was once every other refueling outage. When it was issued, the IP was included in Appendix B to the old IMC 2515 program which listed regional initiative inspection procedures. The team was unable to determine the rational for the change in implementation frequency. During the 10 years the IP was part of Appendix B, it was used on a limited basis for inspections at only 15 docketed reactors. The decision to implement IP 62001 as a regional initiative activity under Appendix B and subsequent limited usage resulted in the inspection program guidance for boric acid corrosion being ineffectiveness in ensuring that licensees were properly dealing with boric acid leakage. The decision to not make IP 62001 a mandatory inspection under the "core program" is consistent with the level of importance exhibited by the NRC staff for boric acid corrosion (see Section 3.1._ for additional discussion). In interviews with the NRC staff, some members indicated that the inspection resource estimation of 8-hours was not sufficient to review a boric acid corrosion program and its implementation. In reviewing DBNPS's boric acid corrosion program the team agreed that the estimate was low.

An NRC inspection area that is related to alloy 600 nozzle cracking is the review of inservice inspections (ISI) activities. Applicable inspection guidance is provided by Inspection Procedure Attachment 71111.08, Inservice Inspection Activities. Prior to the ROP, the guidance was prescribed in IP 73753, Inservice Inspections. There was no explicit inspection guidance in either documents to review alloy 600 locations that are potentially venerable to PWSSC. As noted in Section 3.3.2, NRC inspections in the 1998 and 2000 RFOs reviewed CRDM and reactor head areas but did not identify any unusual conditions with boric acid that had been in the areas.

As noted in Section 3.1._, GL 88-05 did not have a corresponding temporary instruction for follow up inspection of licensee implementation of actions resulting from the GL, however, an audit was performed at ten sites to review boric acid corrosion program. The team noted that the audit guidance did not include reactor nozzle penetrations or other Alloy 600 penetration that are potentially venerable to PWSSC.

DBNPS's failure to learn from operating experience and properly manage VHP nozzle degradation and boric acid corrosion is discussed in Section 3.2.4. The team reviewed the previous two NRC inspections of the DBNPS's corrective action program, IP 40500 inspection in August 1998 and PI&R inspection in February 2001, and noted that operating experience implementation was reviewed in each inspection. No significant problems with DBNPS's operating experience activities were identified in these inspections. IP 71152, Identification and Resolution of Problems, provides very limited inspection guidance for reviewing licensee Resolution of operating experience issues. IP 90700, Feedback of Operational Experience Information at Operating Power Reactors, was a regional initiative inspection under Appendix B of IMC 2515 before the IP was canceled in September 2001. Between November 1994 and October 1999, IP 90700 was used at 29 docketed reactor sites (data on IP 90700 usage for the remaining time frame that it was in place was not available). The rational provided by NRR for canceling this IP, along with IP 62001, was the limited utilization of the IPs under the ROP.

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Both IPs were included in Appendix B, Supplemental Inspection Program, as part of the ROP until they were canceled. As discussed in Section 3._._ the team questioned the rational of canceling IPs from Appendix B, based on limited ROP usage since the ROP structure provides limited opportunities to use the IPs in Appendix B. Based on DBNPS's poor OE usage, the frequent use of IP 90700 as a regional initiative inspection and the limited OE guidance in IP 71152, the team concluded that the ROP does not properly emphasize the review of OE.

To assess the NRC's ability to have recognized and acted upon the symptoms of RCS leakage in containment and boric acid on the reactor head the team reviewed related inspection guidance, the actual number of inspector containment entries, and questioned the inspectors on their containment activities. Inspection Procedure Attachment 71111.20, Refueling and Other Outage Activities, lists only a few specific activities that would require a containment entry during a refueling outage. One example is the guidance for a containment walkdown prior the reactor startup to verify that debris has not been left which could affect containment sump performance. While this does require an actual containment entry, interview with inspectors suggested that the scope of the containment walkdown inspection was not broad enough. They mentioned that prior to the ROP, inspectors would typically performed perform a thorough inspection and walkdown of containment prior to restart. With the current guidance in 71111.20 and the more prescriptive nature of the ROP there is uncertainty if this "good practice" will continue to be performed. In light of DBNPS head degradation the team believes that inspections of structures and passive components in containment during the refueling outage has merit. This could entail a review of important component for obvious signs of deterioration, such as the containment liner, the reactor vessel and major RCS components. When reviewing previous DBNPS inspection reports another good practice was noted which is not captured in current inspection guidance and may not be performed in the future. This dealt with the review of Mode restraints and verification that they are properly disposition prior to startup.

During discussions with some inspectors the team was informed that observation of fuel movement in the containment was previously required by the inspection guidance, but that Attachment 71111.20 now allows this to be done by remote video cameras from outside the containment. The team reviewed 71111.20 and noted that verification of the proper location for fuel assemblies is allowed by review of videotape or core physics testing, but that the guidance for verification of foreign material controls during refueling activities would require a containment entry. The team concluded that inspection guidance related to fuel movement does require containment entries but that some inspectors were confused by the wording in the IP.

When questioned if they reviewed the symptoms of RCS leakage in containment, some inspectors stated that the ROP inspection scope did not include a review of some of the symptoms. Radiation monitor fouling and inspection of the head were examples that were mentioned. The team disagreed with this view because fouling the radiation monitors with iron oxide and reddish brown boric acid on the head were indication of potentially significant problems that can be inspected under the ROP. Determining an adequate number of containment entries by inspectors during refueling outages is directly related to inspection scopes and corresponding inspection activities. In 1998 and 2000 the resident inspector and senior resident inspector had a total of seven containment entries during each RFO. To benchmark this information the team obtained resident inspector containment entries for five other sites. ***DISCUSS RESULTS*** The team concluded......

As noted in Section 3.3.2, Appendix D, Plant Status, to IMC 2515 provides limited guidance on the methodology for reviewing corrective action documents routinely initiated by the licensee. Specifically the team questioned if the senior resident inspector read the CR description pertaining to boric acid found on the reactor head in 12RFO of if the senior resident inspector was aware of the issue by some other means, such as log review, abbreviated description review or meeting discussions. Since there is no specific guidance for these reviews, the team concluded that future reviews of corrective action documents could also miss crucial opportunity to follow up on licensee resolutions of potentially significance safety issues.

The February 2001 PI&R inspection, as discussed in section 3.3.2, did not review any of the issues/ problems related to RCS leakage or boric acid on the reactor head. Clearly, the longstanding nature of the problems and the ineffective licensee corrective actions satisfied the expectation that a PI&R inspection would review this type problems. The guidance in IP 71152 for screening issues to be reviewed by the PI&R was a potential area that could revised to address this situation.

Review of the ROP significance determination process (SDP) and interaction with DBNPS head degradation identified two noteworthy points. First, the SDP review to determine the safety significance of the head degradation has required a large amount of time and resources. Currently the SDP review is not completed and has been ongoing for five months. This review highlights the difficulty in determining the probability of failure for degraded, but still functioning components. The NRC has had difficulty with other SDPs in which the performance deficiency did not result in an actual failure but there was some degradation in the component or system to satisfy its design basis function. Part of the difficulty stems from technical limitations of risk assessments and SDPs in that pressure boundary integrity does not appear to be treated explicitly in PRAs. The second point involves the RC-2 event from 1998 (see Section 3.3.2) and the fact that an SDP review for this issue would most likely result in a Green finding. In 1999 this event received escalated enforcement, Severity Level III violation. This event also dealt with a degraded pressure retaining function, however, an analysis concluded with three body-to-bonnet fasteners corroded the valve would since maintain the integrity of the RCS under design loading conditions. These two items point out difficulties and limitations of the SDP.

As noted in Section 3.3.3, the ROP performance indicators for DBNPS in the barrier cornerstone have been Green since ROP implementation. Given that the VHP nozzle through wall leakage was ongoing during this time frame, the usefulness of the ROP barrier PIs to provide meaningful information regarding the condition of the three barrier is questionable. The current barrier PIs should be reviewed for possible improvements.

The ROP structure doesn't allow the implementation of non-baseline inspections unless a greater than green finding is identified. Prior to this event, all ROP Performance Indicators and inspection findings were Green, indicating a lack of risk-significant issues at DBNPS. Subsequent to the identification of the DBNPS head degradation, Region III invoked Manual Chapter 0350, Oversight of Operating Reactor Facilities in a Shutdown Condition with Performance Problems, without meeting the prerequisites of the procedure. Specifically, DBNPS performance was not degraded into the multiple/repetitive degraded cornerstone, or the unacceptable performance columns of the action matrix. The LLTF concluded that timeliness of the risk assessments and the ROP structure, allowed an issue such as this being viewed as significant from a deterministic perspective, yet the staff having limited option for further NRC action from a program standpoint.

NRC enforcement focus was shifted by the risk-impact of issues and enforcement actions have not been implemented consistently due to differing staff views. Enforcement (EA 97-414) was issued citing the Maintenance Rule (10 CFR 50.65) involving Inconel Alloy 600 RCS instrument nozzle cracking at SONGS 2 and 3 due to a lack of staff support for enforcement against the licensee's Technical Specification for reactor coolant pressure boundary leakage. In addition, the staff issued the citation as a Severity Level IV, versus a Severity Level III when the staff could not come to full agreement. The licensee presented an argument that was focused on nozzle ejection stemming from catastrophic failure rather than from boric acid wastage.

The team conducted a limited review of past NRC lessons-learned reviews to determine whether there were any recurring problems. This included lessons learned reviews for Millstone, IP2, and South Texas Project). The task force identified a number of problem areas that were identified in these past reviews that are similar to some of the regulatory process issues associated with this review. These issues are described in Appendix F.

3.4.2.2 Recommendations

3.4.2.2.1 Recommendations for NRC

- Review the significance determination process for limitations in evaluating degraded conditions and applying risk assessments. Consideration should be given to the use of deterministic methods in assessment evaluations;

- Review the ROP inspection effort during refueling outages given the large of amount of licensee activities in the relatively short outage time frame, limit future opportunities during operating cycle, and a lack of previous inspections for passive components;

- Consideration should be given to proceduralizing "good practices" such as containment building tours, Mode restraint reviews prior to startup, etc;

- Evaluate performance indicators in barrier integrity cornerstone to determine if improvements are needed,

- Evaluate the reactivation and implementation of inspection procedures 90700 and 62001 or provide comparable level of guidance for operating experience and boric acid corrosion program inspections;

- Consider risk of repetitive LCO entries or continuing problems; develop inspection guidance to focus on repetitive multiple tasks for significance (i.e. CAC cleaning/ALARA);

- Develop inspection guidance for resident inspector samples of licensing requests to understand the basis and provide necessary feedback to the project manager;

- PI&R guidance should be strengthened in the area of utilizing experience from members of the staff to develop area of review, i.e., handing off issues to the PI&R team, and screening corrective action issues when determining issues for follow up review;

- Develop NRC criteria for inspection of industry initiatives. Provide inspection guidance to address selected industry operational experience. Initiate GC-specific inspection procedures. Incorporate GC references in inspection procedures

- Assess the need for changes to the ROP to allow regional follow up on issues of potential safety significance

- Determine if the results from reviewing previous lessons-learned task force efforts suggest a need for programmatic guidance in this area

3.4.3 The Industry Failed to Provide Adequate Guidance for Detecting and Correcting VHP Nozzle Cracking and Boric Acid Corrosion

Despite many years of industry operating experience and research results related to boric acid corrosion and VHP cracking, industry guidance did not result in the timely detection of VHP nozzle leakage at DBNPS. Some of the guidance associated with VHP nozzle cracking and boric acid corrosion control appeared to be wrong or incomplete. For example, the acceptability of visual inspections alone does not appear to account for the worst case corrosion rates, which could result in an unacceptable level of wastage in one cycle. Other guidance reinforced the licensee's view that it was acceptable to leave boric acid deposits on the head because it stated that a coating of boric acid was actually beneficial under certain circumstances. No guidance was provided on how to actually remove boric acid deposits from the head, for example, by power washing with water. Also, the RPV head insulation was not deflected by the large amounts of boric acid deposits even though the BWOG guidance indicated that such bulging would be an indication of VHP nozzle leakage. Further, industry organizations did not follow up on implementation of existing guidance nor provide effective oversight of licensee activities related to boric acid corrosion control or VHP degradation.

The task group determined that the combination of inadequate industry guidance in some areas, misapplication of some guidance by DBNPS, and a lack of oversight by industry groups and commercial organizations all contributed to the underlying causes of the DBNPS event.

3.4.3.1 Detailed Discussion

Industry Technical Guidance - The industry effort to address boric acid corrosion control provided general guidelines to licensees to establish their programs that was based on conducting a few exploratory tests to gage the potential for damage due to boric acid corrosion. However, the extrapolation of the test results and the underlying message may have de-emphasized plant vulnerability to a significant mode of corrosive attack on VHPs.

The Electrical Power Research Institute (EPRI) and Nuclear Maintenance Application Center (NMAC) joined to provide assistance to the utilities in addressing the requirements of Generic letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR plants," issued in March 1988. The EPRI "Boric Acid Corrosion (BAC) Guide Book," issued in April 1995, was the product of this joint effort. A subsequent revision to the Guide Book was issued in November 2001. Its objective was to provide a single source of comprehensive information to help utilities address plant boric acid control and general leakage reduction issues.

The BAC Guide book draws a conclusion (Section 8.3.3 in Revision 1 and 8.1.2 in Revision 0) that "It is hypothesized that, under certain conditions, boric acid deposits on the vessel head actually protect the surface from corrosion by keeping the water away from the surface. ...If the leakage rate is low and its source is above the boric acid deposits, heat transfer through the deposits will evaporate the incoming water and thereby keep the surface dry. On the other hand, if the leakage rate is high or if the source is located within the boric acid deposits, the deposits will be wetted, leading to high corrosion rates at the vessel head." This phenomenon explains a probable chemical reaction that happened at DBNPS. However, the illustration of this problem is given to a sketch with boric acid deposits building up from a flat surface as result of dripping boric acid from above, akin to CRDM flange leakage. RPV head penetration cracking was a well known problem for more than two decades and the task force judged that the industry should have analyzed more conservative scenarios for corrosion as it relates to VHPs.

The BAC Guide Book Revision 1, Section 4.7, discusses the various tests performed by EPRI and CE. The CE tests were performed with the nozzle pointed downwards contrary to the typical plant application. The EPRI tests had the nozzles mounted upwards and the tests demonstrated that the maximum corrosion depth is near the point where the borated water is injected into the annulus. The assessment further states that "Corrosion occurring at this location would not be seen during the visual inspection of the vessel surface, although boric acid deposits on the metal surface would indicate that there has been a leak " This significant finding of corrosion hidden from visual surface inspection was not investigated further to understand more conservative or worst-case scenarios. The test results indicate a maximum corrosion rate of 4 inches per year. Such a high rate of corrosion, not identified in the visual inspection at its early stages, could propagate to a point of rupture in a typical 18 month-to-two-year cycle. The possibility of observing surface deposits and its quantity would depend on the rate of leakage and the rate of corrosion at the time of the inspection. Leaving rusty deposits on the surface while corrosion continues in the inner layers at more than one VHP appear to be a clear possibility. The present inspection program was not evaluated by industry for its capability to detect such impending failures. The team concluded that the industry continued to rely on visual inspections that did not require the removal of the RPV head insulation, after having identified this critical vulnerability of VHP area corrosion and recognizing a wide range in the rate of corrosion.

The task force judged that these deficiencies in the industry technical guidance may have contributed to misunderstandings by the licensee regarding implications of boric acid corrosion and the effects of VHP leakage. The misunderstandings in turn contributed to a lax approach taken by the licensee in addressing RCS leakage and boric acid corrosion issues. In the view of the task force, the industry and NRC should take steps to ensure that accurate technical information and guidance is made available to licensees.

In the initial edition of the book , Section 6.2 addresses detecting leakage during operation. This guidance could have alerted DBNPS to the continuing boric acid leakage. The Containment Air Particulate Monitor was identified in the report to have the capability to monitor 0.1 gpm assuming normal primary system activity and no failed fuel. The containment Air Cooler Condensate Monitors were referred to as another system capable of providing clear, sensitive information. Continued clogging of containment air coolers and the containment monitor filter clogging were important indications of RCS leakage at DBNPS. This condition prevailed even after 12RFO when CRDM flange leakage was corrected through repairs. In this instance, the task force judged that if the licensee had been more cognizant of the guidance, the RPV head leakage may have been detected earlier.

The task group found examples of industry policy contributing to misconceptions of the consequences of RCPB leakage and associated corrosion. The NUMARC position on CRDM VHP cracking was discussed in the June 16, 1993, letter to NRC. The letter forwarded the PWR owners groups safety assessments of VHP cracking. The owners group reports concluded that cracking was not an immediate safety concern. NUMARC added that if a through-wall crack would occur, the boric acid deposition expected would be detectable by inspection activity conducted in accordance with GL 88-05. NUMARC believed that detection of leakage would prevent any significant BA-induced wastage that would challenge ASME limits. This was a relatively early indication that a connection was made by industry between VH penetration cracking and the potential for head wastage.

The NEI letter to NRC dated May 24, 1995, provided the status of industry activities related to VHP cracking. It discussed pilot plant inspection results, refers to NUREG/CR-6245, the owners group safety evaluations, GL 88-05 programs, crack growth rate model development, and VHP re-inspection efforts. However, it maintained the position that VHP degradation was a problem with low safety significance. The task force judged that, given the operating experience overseas, the range of experimental results (published in industry reports), and the regulatory requirements associated with RCPB leakage, that the industry position was not appropriate and that industry groups were not sufficiently aggressive in addressing RPV head penetration integrity concerns.

B&W, nor the B&W Owners Group made formal recommendations to licensees in the areas of RCS leakage or boric acid corrosion control, and specifically to follow up on generic communications or industry guidance. Based on discussions with industry representatives, the task group determined that B&W/Framatome has not issued formal recommendations to licensees in the areas of boric acid control, RCS leakage or leak detection. The task force found no follow up on GL 88-05 by the B&W owners group. The owners group referred to report BAW-2301 as the B&W owners group follow up to GL 97-01 **{Review BAW-1403 for guidance to licensees.}** The task force found important areas that needed guidance to be lacking. For example, no guidance was provided to licensees on how to remove boric acid deposits from the RPV head. DBNPS used several methods, including a water wash. Prior to RFO 12, the licensee considered the possible effects of water washing the RPV head, but lacked technical guidance from industry to aid its decision. Also, despite industry guidance that bulging insulation is a reliable indicator of leakage and boric acid corrosion, no insulation bulging or defects were observed at DBNPS before February 2002.

In 1996, NEI issued a document that included a discussion about an economic model that licensees could use to aid decision-making related to RPV head penetration inspection and repairs. The NRC mentioned the model in GL 97-01, disagreeing with NEI that economic factors were a primary consideration. However, the task force found no evidence that the staff actually reviewed the model, nor that the industry changed its position relative to the GL 97-01 statement. The task force surmised from interviews with licensee personnel **(see Section 3.2.??)** That the licensee did indeed place undue weight on economic factors associated with RPV head cleaning, RCPB leak detection and correction, and VHP degradation issues. The task force concluded that industry emphasis of economic factors evidenced by providing licensees with economic analysis "tools" could have been a contributor to the approach taken by the DBNPS licensee and, in turn, contributed to the 2002 event.

<u>Industry Self-Assessment</u> - The task force reviewed Institute of Nuclear Power (INPO) and World Association of Nuclear Operators (WANO) evaluation reports involving DBNPS to determine whether INPO or WANO had assessed and documented any problems involving VHP nozzle cracking or boric acid corrosion of the RPV head. Two of these evaluations documented problems involving boric acid corrosion of pumps and valves. For example, the March 10, 1998 interim report of WANO-AC's 1997 peer review of the DBNPS, documented an area for improvement in the maintenance area for not identifying and correcting boric acid

accumulation on pumps and valves. The November 1999 INPO Evaluation of DBNPS, noted that in September 1998 the reactor coolant system pressure boundary was degraded because of boric acid corrosion of the pressurizer spray valve **(refer also to Section 3.3.__ of the report)**, as well as nine other valves that were discovered with boric acid corrosion.

These evaluations did not result in the integration of the symptoms and potential indicators of the VHP nozzle leaks. For example, the November 28, 2001, interim report of INPO's 2001 evaluation of DBNPS identified a strength in the radiological protection area involving radiation dose control. One of the supporting examples pertained to the DBNPS radiation protection servicemen setting up and operating the hot water pressure washer in a non-radiological control area, which allowed them to identify and correct several problems with the operation of the unit prior to its use inside the containment. INPO concluded that this contributed greatly to the CAC cleaning being completed with no delays or problems, which resulted in a savings of about 100 millirem over previous cleaning methods. There was no assessment in the report regarding why the CACs required cleaning in the first place (i.e., chronic RCS leakage). There was no discussion regarding the past use of a kerosene burner (i.e., open flames) inside the containment to heat the water for the power washer. Additionally, there was no discussion that this activity, which was a work-around caused by the active RCS leak, was one of the highest dose jobs during 2001. The task force considered the results of the these assessments to be lacking, in that apparent weaknesses in the licensee's boric acid corrosion control program and RCS leakage detection/correction were not highlighted.

The task force attempted to determine if the vendor that conducted the RPV head inspection at DBNPS (Framatome) tracked plant conditions for comparison. The task force did not find this to be a priority with the vendor. The task force considers the experience and information available to the vendor by virtue of assessing a number of plants to be a valuable resource that the industry should exploit. Licensees should develop a mechanism to tap this information to contrast the condition of their facility with those found throughout the industry.

<u>VHP Cracking Model and Other VHPs</u> - The VHP crack susceptibility model predicted that cracking at DBNPS would begin in 2003. **[Ask Ed to confirm]** NRC staff interviewed by the task force discussed the range of uncertainties involved in the model. Some staff thought that additional testing was needed to improve the model over the full range of existing plant conditions. Given the operating experience contained in the French data on VHP cracking indications, the task force questioned the basis of the model. The task force concluded that industry should direct resources toward providing an improved experimental basis for crack susceptibility modeling.

The task group review found examples of other RCS penetrations (see section 3.1 for examples) that are susceptible to corrosion similar to RPV penetrations. For example pressurizer heater, lower RPV head, and thermo-well penetrations have or could (by virtue of composition, construction, and operating environment) exhibit cracking and leakage. The task force concluded that efforts should focus on assessing other alloy 600 nozzles for susceptibility to leakage.

3.4.3.2 Recommendations

3.4.3.2.1 Recommendations for NRC

- NRC should work with industry to develop guidance for voluntary initiatives such as testing to more fully understand boric acid corrosion effects. NRR should take steps to review guidelines in industry topical reports (see Recommendations in Section 3.3.7). A possible step would be to assign NRC technical project managers to evaluate industry tests and review the widely distributed guidelines for adequacy and suitability.

3.4.3.1.2 Recommendations for Industry

- Industry should review and revise existing guidance related to boric acid corrosion control and RPV head penetration inspection and repair to better support licensee decision making involving these issues.
- Industry should utilize plant condition information gained by vendor organization conducting inspection and repair activities at multiple plants.
- Industry should review the approaches used by licensees to consider economic factors involved with RPV head penetration inspection and repair. This might include conducting representative cost/benefit analyses of RPV head inspections that would include factors for dose, cost, and time involved.
- Industry groups should improve dissemination of information to members and hold members accountable for following guidance/recommendations. For example, one mechanism that would aid dissemination is for licensee staff to regularly attend Owner's Group meetings related to RPV degradation and inspection.
- The industry should conduct further testing and analysis to develop a more reliable crack model and should assess the susceptibility of other RCS components fabricated from Alloy 600.

Appendix A: Consolidated Recommendations

No.	Recommendation	Report Reference (Section)	Action Org.	
[62]	Consider providing an integrated listing of studies or major documents containing significant operating experience to ensure that this body of knowledge and experience isn't lost.	3.1.1		
[81]	Consider providing an integrated listing and assessment of issued generic communications including an assessment of their effectiveness	3.1.1		
[124]	Consider studying the unique vulnerabilities of B&W plants with respect to nozzle cracking and boric acid corrosion.	3 1.1		
[27]	Consider performing a study to analyze boric acid corrosion of different materials under varying temperatures and conditions	3 1.1		
[52]	Consider the need for long-term analysis of operational experience by a single group	3 1.1		
[9]	Consider the need for the NRC to review industry guidance documents	3 1.2		
[22]	Consider a periodic review of the status of generic communications.	3 1.2		
[13]	Consider changes to MD 6 4, MD 8 5, and LIC-503 to coordinate office functions and provide appropriate training	3.1.2		
[61]	Consider providing training on significant operational experience	3 1 2		
[46]	Assess the need to enhance the use of foreign operating experience	3 1 2		
[77]	Enhance the dissemination of foreign experience.	3 1 2		
[78]	Update the international experience database originally kept by AEOD.	3 1.2		
[109	Assess whether or not lessons learned have been learned or not	3 1.2		
[10]	Consider the need to verify that corrective actions have been implemented to address past significant generic communications and generic issues.	3.1.3		
[11]	Consider establishing a process for verification of licensee and agency actions to address generic communications Consider also the need to verify the effectiveness of licensee and agency corrective actions to address generic communication	3.1.3		
[30]	Assess the overall scope and process for reviewing operational experience	3.1.3		
[16, 12]	Consider the need to consolidate the generic communication program (LIC-503) and the generic issues program (MD 6 4)	3 1.3		

[24]	Consider establishing criteria for accepting "industry" resolutions for generic communications and generic issues	3.1.3		

	Establish a central operating experience screening group to identify issues for Generic Issues Program based on US and foreign experience	3.1 4		
	Evaluate/revise guidance for proposed generic communications	3 1 4		
	Determine if screening criteria for candidate generic issues are acceptable.	3 1 4		
	Assess consolidation of generic communications process and the Generic Issue Program (GIP).	3 1 4		
	Ensure that generic requirements or guidance are not eliminated or undermined when making changes to regulatory processes (e.g , deleting inspection procedures)	3 1 4		
	Update MD 8 5, MD 6 4, and NRR Office Instruction LIC 503, "Generic Communications Affecting Nuclear Reactor Licensees."	3 1 4		
	Enhance criteria for Boric Acid Corrosion Control (BACC) programs	3 1 4		

APPENDIX B - LIST OF ACRONYMS

The following acronyms were used in this report:

AEOD	Office for Analysis and Evaluation of Operational Data
AIT	Augmented Inspection Team
ANO	Arkansas Nuclear One
ASME	American Society of Mechanical Engineers
B&W	Babcock & Wilcox
BAC	Boric Acid Corrosion
CAC	Containment Air Cooler
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
B&WOG	Babcock & Wilcox Owners Group
DBNPS	Davis-Besse Nuclear Power Station
EPRI	Electric Power Research Institute
FENOC	First Energy Nuclear Operating Company
IMC	Inspection Manual Chapter
IPSN	The French Nuclear Regulatory Authority of France
ITS	Improved Technical Specifications
LAR	License Amendment Request
LWR	Light Water Reactors
MCEB	Materials and Chemical Engineering Branch
NEI	Nuclear Energy Institute
NMAC	Nuclear Maintenance Application Center
NUMARC	Nuclear Management & Resource Council
ONS	Oconee Nuclear Station
PI	Performance Indicators
PPR	Plant Performance Review
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RCS	Reactor Coolant System
RFM	Request for Modification
ROP	Reactor Oversight Process
RPV	Reactor Pressure Vessel
SDP	Significance Determination Process
SER	Safety Evaluation Report
TRM	Technical Requirements Manual
TS	Technical Specifications
VHP	Vessel Head Penetration

APPENDIX C - LIST OF DOCUMENTS REVIEWED

Joe:

- IP2 Lessons-Learned Task Group Report
- STP Lessons-Learned Report
- Millstone/Haddem Neck Lessons-Learned and/or Task Action
- Industry guidance document for managing NRC commitments
- NRR Office Instructions for code relief requests, exemptions, amendment requests, etc.
- Copy of November 19, 1993 NRC letter
- NUMARC 93-01, Section 9.3.1
- NUREG referenced in AIT report
- NRR Operating Instructions LIC-100, LIC-101, LIC-403, LIC-500
- NUREG 1801, Generic Aging Lessons Learned (GALL) Report, April 2001
- FENOC letter to NRC dated November 15, 2000, Commitment Change Summary Report
- NEI 99-04, "Guidelines for Managing NRC Commitment Changes," COM-204, "Interfacing with Owners Groups, Vendors and NEI," License Amendment 234
- License Amendment 180
- NRC letter to FirstEnergy, "Generic Letter 97-01, "Degradation of CRDM/CEDM Nozzle and other Vessel Closure Head Penetrations": Review of the Responses for the Davis-Bese Nuclear Power Station, Unit 1," November 29, 1999
- Memorandum from the Division of Engineering to the Division of Licensing, dated June 14, 1999.
- Memorandum from the Division of Engineering to Inspection and Licensing Program Branch, April 29, 1991
- NRC letter to the licensee dated February 8, 1990
- GL 97-01 closeout letter dated November 29, 1999
- Memorandum from the Division of Engineering to the Division of Licensing Project Management, dated June 14, 1999
- NRC inspection reports 98005 and 98007
- FENOC RAI response (Jan 14, 1999)
- Memorandum from the Division of Engineering to Inspection and Licensing Program Branch, April 29, 1991
- final version of Inspection Procedure 62001 issued on August 1, 1991,
- Memo from Richardson to Russell (dated December 12, 1991

- Mar. 24, 1992, memo from Wiggins to Richardson and Nov. 30, 1993, Taylor to Commission

ED

- Information Notice 2002-11: "Recent Experience with Degradation of Reactor Pressure Vessel Head," March 12, 2002 [ADAMS Accession No. ML020700556]
- Bulletin 2001-01: "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," August 3, 2001 [ADAMS Accession No ML012080284]
- Information Notice 2001-05, "Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3," April 30, 2001 [ADAMS Accession No. ML011160588]
- Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," April 1, 1997.
- Information Notice 96-11, "Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations," February 14, 1996. Information Notice 86-108, Supplement 3, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," January 5, 1995.
- NUREG/CR-6245, "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking," October 1994.
- Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks," August 30, 1994.
- Information Notice 90-10, "Primary Water Stress Corrosion Cracking of INCONEL 600," February 23, 1990.
- Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988.
- Information Notice 86-108, Supplement 2, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," November 19, 1987.
- Information Notice 86-108, Supplement 1, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," April 20, 1987.
- Information Notice 86-108, "Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion," December 29, 1986.
- Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," June 2, 1982.
- Information Notice 82-06, "Failure of Steam Generator Primary Side Manway Closure

Studs," March 12, 1982.

- Information Notice 80-27, "Degradation of Reactor Coolant Pump Studs," June 11, 1980.
- FENOC Root Cause Report, 2002
- EPRI Boric Acid Corrosion Control Handbook, 1995
- WCAP-13565, Rev. 1, "Alloy 600 Reactor Vessel Head Adaptor Tube Cracking Safety Evaluation, February, 1993 (Proprietary).
- CEN-607, "Safety Evaluation of Potential for and consequences of Reactor Vessel Head Penetration Alloy 600 ID-initiated Penetration Cracking, May 1993.
- BAW-1019P, "Safety Evaluation for B&W-Design Reactor Vessel Head Control Rod Drive Mechanism Nozzle Cracking, May, 1993.
- NRC Safety Evaluation, "Alloy 600 Control Rod Drive Mechanism (CRDM)/Control Element Drive Mechanism (CEDM) Pressurized Water Reactor Vessel Head Penetration Cracking," November 19, 1993.
- Letter from Alex Marion (NEI) to Brian Sheron (NRC) transmitting industry white paper entitled, "Alloy 600 RPV Head Penetration Primary water Stress Corrosion Cracking," March 5, 1996.

Tom

- The NRC Internal Foreign Trip Report dated November 15, 1991.
- NUREG/CR-6245 "Assessment of Pressurized Water Reactor Control Rod Drive Mechanism Nozzle Cracking", October 1994.
- Proceedings of International Symposium on Plant Aging and Life Predictions of Corrodible Structures on May 15-18 1995: Status of Alloy600 Components Degradation By PWSCC in France: Incentives and Limitations of Life Predictions as Viewed by a Nuclear Safety Body.
- Generic letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR plants," issued in March 1988.
- The EPRI "Boric Acid Corrosion (BAC) Guide Book," issued in April 1995.
- The EPRI "Boric Acid Corrosion (BAC) Guide Book," Revision 1, November 2001.

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ABBREVIATIONS

ANO-1	-	Arkansas Nuclear-1
B&WOG	-	Babcock & Wilcox Owners Group
EPRI	-	Electric Power Research Institute
IPSN	-	The French Nuclear Regulatory Authority of France
NEI	-	Nuclear Energy Institute
NSIR	-	Nuclear Security and Incidence Response
NRR	-	Office of Nuclear Reactor Regulations
OCA	-	Office of Congressional Affairs
OE	-	Office of Enforcement
OGC	-	Office of the General Counsel
OI	-	Office of Investigation
OIG	-	Office of the Inspector General
RES	-	Office of Nuclear Regulatory Research
STP	-	Office of State and Tribal Programs
RI	-	Region I
RII	-	Region II
RIII	-	Region III
RIV	-	Region IV

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Appendix E

Primary System Leakage and Boric Acid Corrosion Operating Experience at U.S. Pressurized Water Reactors (1986-2002)

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1. BACKGROUND INFORMATION

To determine whether Davis-Besse was an outlier with respect to boric acid leakage operating experience, domestic and international operating experience was reviewed for the period 1986 through the first quarter of 2002. For the period of interest, 73 Pressurized Water Reactors (PWRs) were included in the sample. NRC generic communications relevant to boric acid issues that were issued since 1980, were also reviewed to determine what guidance was provided to the industry, and whether or not this guidance was utilized by Davis-Besse Nuclear Power Station (DBNPS).

2. DOMESTIC BORIC ACID LEAKAGE OPERATING EXPERIENCE

A review of operating experience relevant to boric acid leakage and corrosion in PWRs was accomplished for the period 1986 through the first quarter of 2002. This information was entered in a database which was then sorted to determine any trends and patterns. Licensee Event Reports (LERs) were the basic source of boric acid leakage events. Two additional events were added to the database because they involved boric acid leakage and reactor pressure vessel (RPV) head wastage, but were not recorded in a licensee event report (LER). Each operating experience document may have discussed more than one component, system, or was applicable to more than one unit. Besides listing the component that was affected by the boric acid leak, other information was sorted by Nuclear Steam System Supplier (NSSS) designer, design type, plant operating age, number of operating years at the time of the event report, and year of occurrence.

2.1 Numerous Boric Acid Leakage and Corrosion Events Have Been Documented

Figure 1, "Reported Areas Involving Boric Acid Leakage (1986-2002)," lists the component experiencing a boric acid leak, or was affected by a boric acid leak. As seen by the figure, the most prominent events involving boric acid leakage included 15 documents relating to control rod drive mechanism (CRDM) leaks, 13 documents relating to reactor coolant system (RCS) nozzle leaks, nine documents relating to pressurizer (PZR) instrumentation nozzle leaks, seven RCS valve leaks, seven RCS instrumentation leaks, and seven pressurizer (PZR) heater sleeve leaks. Other less prominent events include four documents relating to corrosion of the steel containment vessel, four events relating to RCS nozzle leaks, three events involving wastage of the RPV head, three events involving wastage of the pressurizer.

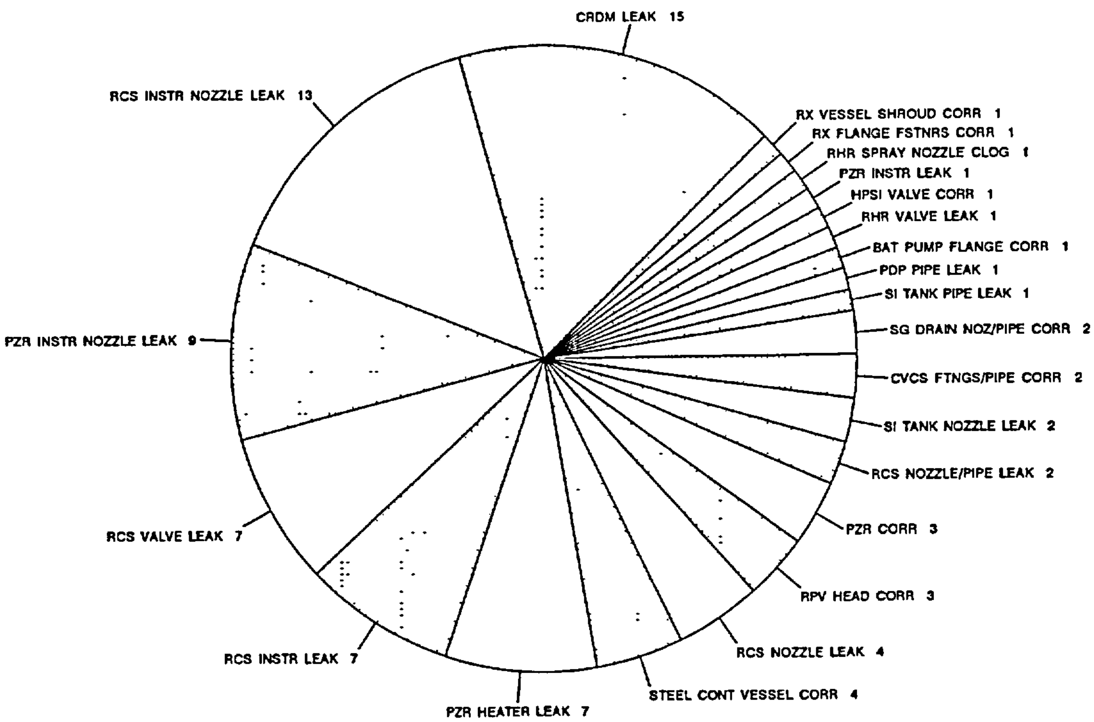

Figure 1. Reported Areas Involving Boric Acid Leakage (1986-2002)

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2.2 Number of Operating Years Prior to Discovery of a Boric Acid Event Is Random When Considering All Components

Figure 2, "Number of Operating Years Prior to Event Occurrence," displays an even distribution of boric acid leakage events Figure 2 lists the plants that have reported a boric acid leak and the number of years of operation to the time that the leak was discovered When taken as a group, it appears equally likely to have a boric acid leak after only a few years of operation, as it does after a long period of operation. In general, however, smaller components take longer to develop a leak than do the larger components. This observation is evident in subsequent figures.

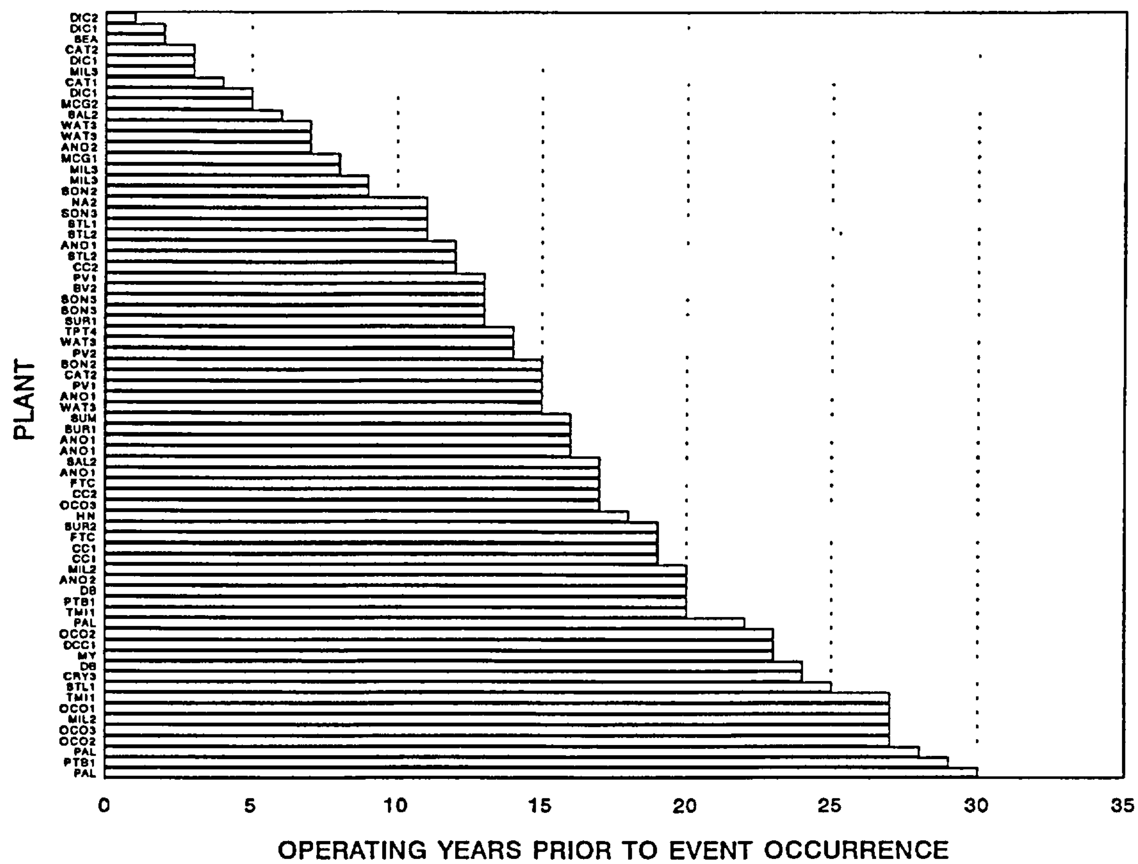

Figure 2. Number of Operating Years Prior to Event Occurrence

2.3 Babcock and Wilcox and Combustion Engineering Plants Are Highly Susceptible to Boric Acid Leakage and Corrosion

As shown in Figure 3, "Percent of NSSS Design Manufacturers Reporting Boric Acid Leakage" Babcock and Wilcox (B&W) and Combustion Engineering (CE) plants appear to be highly susceptible to boric acid leakage and corrosion. One hundred percent of B&W plants have reported boric acid related problems Given the high incidence rate of boric acid leakage problems at B&W plants, DBNPS should have been alerted and taken appropriate corrective actions. Combustion Engineering plants were broken up into the older CE plant design (12 units total) and the newer CE80 design (3 units total) to see if any differences were noted. As shown in the figure, 100 percent of the older CE plants reported boric acid leakage problems, while 67 percent of the CE80 design (two of three units) reported boric acid leakage problems.

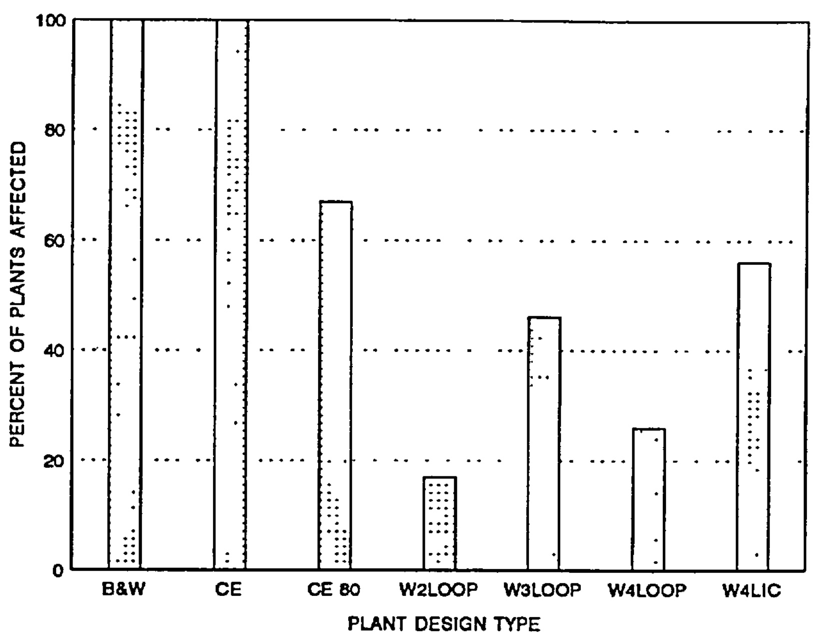

Figure 3. Percent of NSSS Design Manufacturers Reporting Boric Acid Leakage

2.4 Westinghouse designed plants are less susceptible to boric acid leakage than other PWRs

Figure 3 also shows that the Westinghouse plants were less susceptible to boric acid leakage problems than were other PWR designs. Within the Westinghouse group, there were large differences in operating experience. The older Westinghouse two-loop plants (W2LOOP) faired the best at 17 percent (6 plants total) reporting boric acid leakage problems, while the four loop ice condenser version (W4LIC) faired the worst at 56 percent (9 plants total). The Westinghouse three-loop plant (W3L) had 46 percent (13 plants total) reporting boric acid leakage problems and the Westinghouse four-loop plant (W4L) had 26 percent (23 plants total) reporting boric acid leakage problems.

2.5 Control Rod Drive Mechanism Leakage Is Dominated by B&W Plants

As shown by Figure 4, "Control Rod Drive Mechanism Leakage," B&W designed plants dominate control rod drive mechanism (CRDM) leakage. There were 15 documents relating to CRDM leakage of which 9 occurred at B&W plants. When considering that B&W plants make up less than 10 percent of the plants within the sample of 73 PWRs, the B&W plants are greatly over-represented. Figure 4 shows the component that had leaked, the specific facility experiencing the leakage, the design type of the plant, and the number of years of operation prior to the event being discovered. The types of boric acid leakage events include CRDM nozzles (dominant failure), spare CRDM canopies, CRDM seal housings, and a CRDM tube housing.

Combustion Engineering is appropriately represented given that CE plants represent approximately 20 percent of the PWR sample of 73, and approximately 20 percent of the CRDM event reports (3 of 15 reports).

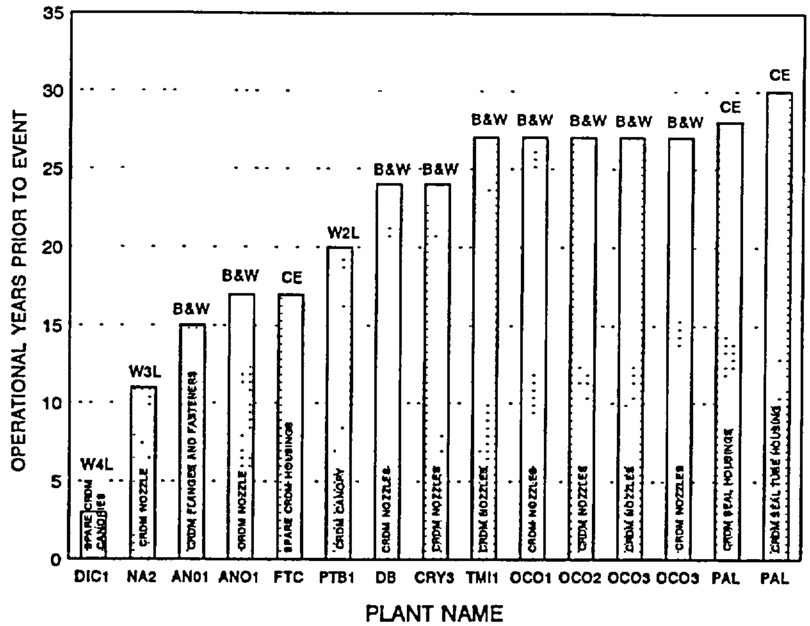

Figure 4. Control Rod Drive Mechanism Leakage

2.6 Extensive Control Rod Drive Mechanism Nozzle Cracking and Leakage at B&W plants

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Table 1, "CRDM Penetration Cracking Experience at B&W plants," provides information on the crack location on the RPV head, crack type, extent of non-destructive examination (NDE) other than cursory visuals on the CRDMs, number of operating years prior to the event report, and the event date. DBNPS management had ample operating experience from other B&W plants from which to make an informed decision about the potential for CRDM cracking and its impact on its plant. As shown in Table 1, B&W plants have had 6 percent of their CRDM penetrations develop through wall cracks, 100 percent of B&W plants have had axial CRDM penetration cracks, and 86 percent of B&W plants have experienced circumferential cracking in at least one CRDM penetration. In addition, DBNPS was aware that all of the other operating B&W plants had experienced axial and/or circumferential CRDM penetration cracking and through wall leaks during the time period that DBNPS was requesting an extension to their operating period from December 31, 2001 to March 2002. DBNPS subsequently discovered through wall CRDM penetration leaks in February 2002 that may have existed since 1996.

Figure 5, "Control Rod Drive Mechanism Penetration Cracking Timeline for B&W Plants," presents a graphical representation of CRDM penetration cracking for all B&W plants. As shown in the figure, DBNPS was the last B&W plant to report cracking However, had the boric acid crystal buildup that was identified during the 1996 refueling outage, the 1998 outage and the 2000 outage that was allowed to accumulate been removed, DBNPS may have been determined that CRDM penetration cracking had occurred long before February 2002. Ample B&W operating experience was available for DBNPS to conclude that a whole (RPV) head inspection was necessary to determine if cracking was evident, but instead made the decision to continue to operate without performing the penetration inspections.

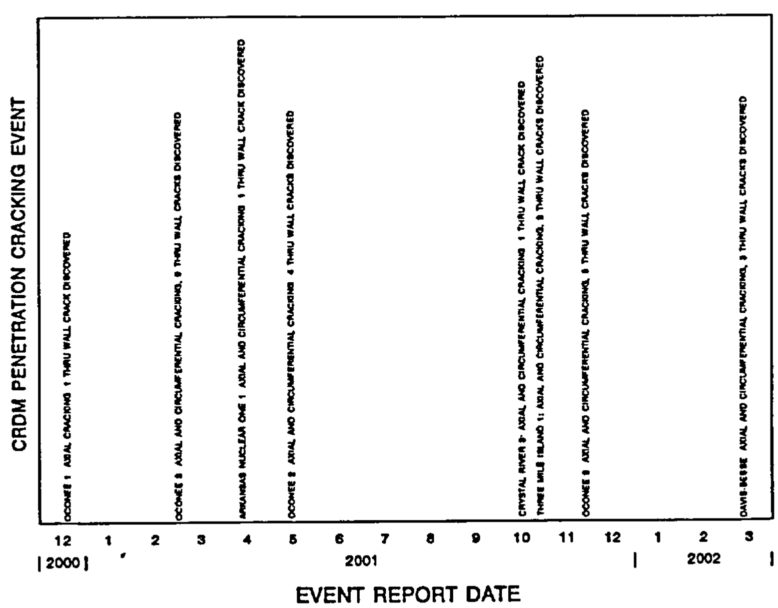

Figure 5. Control Rod Drive Mechanism Penetration Cracking Timeline for B&W Plants

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Table 1. Control Rod Drive Mechanism Penetration Cracking Experience at B&W plants

CRDM ROW*	CRDMs PER ROW	TOTAL	OCO1	OCO3	ANO1	OCO2	CRY3	TMI1	OCO3	DB	PERCENT (%) OF TOTAL WITH CRACKS
1	1	7								1	14% of Row 1 had cracks
2	8	56		2		2			1	3	14% of Row 2 had cracks
3	16	112	1	2		1		1	1		6% of Row 3 had cracks
4	20	140		2	1	1	1	4	3		9% of Row 4 had cracks
5	24	168		3				3	2	1	5% of Row 5 had cracks
THRU WALL CRACK			1	9	1	4	1	3	5	3	6% of CRDMs have experienced thru wall cracks
AXIAL CRACK			YES	YES	YES	YES	YES	YES	YES	YES	100% have had axial cracks
CIRC CRACK			NO	YES	YES	YES	YES	YES	YES	YES	86% have had circumferential cracks
100% INSP			NO	NO	NO	NO	NO	YES	YES	YES	43% of the units had 100% NDE (other than visual)
OPER YEARS PRIOR TO EVENT			27	27	17	27	24	27	27	24	
EVENT DATE			12/4/00	2/18/01	3/26/01	4/28/01	10/01/01	10/12/01	11/12/01	2/27/02	

*Row 1 includes CRDM #1; Row 2 includes CRDMs #2-9; Row 3 includes CRDMs #10-25; Row 4 includes CRDMs #26-45; Row 5 includes CRDMs #46-69.

2.7 Components Having the Most Prevalent Boric Acid Leakage Issues

Operating experience was reviewed to determine the average number of operating years prior to discovery. The operating time to leak discovery was determined by comparing the event date with the date that an operating licensee for the plant was obtained from the NRC. Figure 6, "Average Number of Operational Years Prior to Leakage Event for Selected Components," provides several insights to five of the most prevalent leakage areas, CRDM nozzle leakage (15 reports), RCS instrumentation nozzles (13 reports), pressurizer instrumentation nozzles (9 reports), pressurizer heater sleeves (7 reports), and RCS instrumentation (7 reports) Most reports contained multiple occurrences of leakage. These events and the operational experience to be gained were available to DBNPS. The licensee for DBNPS relied substantially on industry susceptibility models to postpone VHP nozzle inspections. As shown from the operational experience data, DBNPS was within the average operating time period to expect CRDM penetration cracking and leakage. The industry average operating time for CRDM penetration leakage is 21.6 years. The operating time period for DBNPS' discovery of leakage was 24 years, which exceeded the average time period.

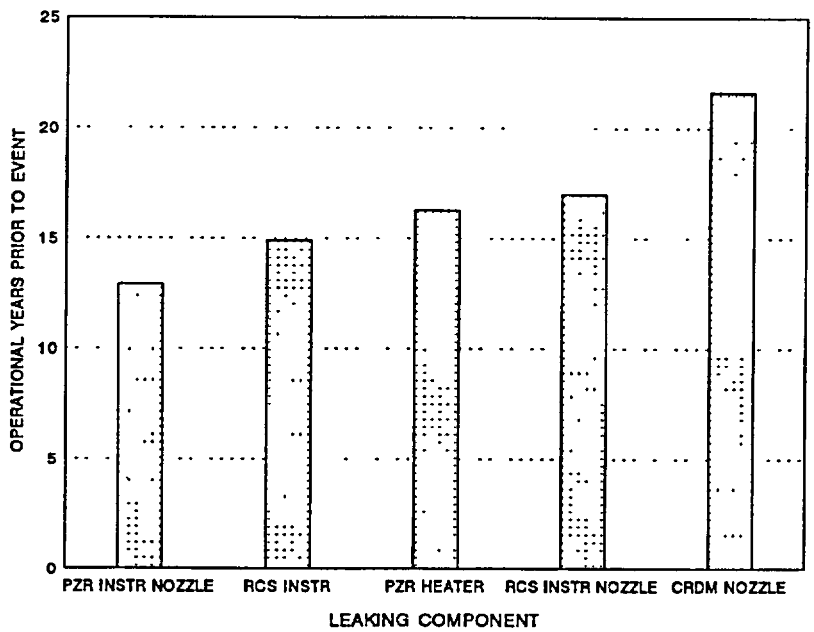

Figure 6. Average Number of Operational Years Prior to Leakage Event for Selected Components

2.8 Reactor Pressure Vessel Metal Wastage Events Caused by Boric Acid Corrosion

Figure 7, "Reactor Pressure Vessel Head Base Metal Wastage Events," shows those plants which have experienced corrosion (beyond surface metal corrosion). The figure also shows the operating years prior to event occurrence. The Turkey Point 4 event in March 1987 was the major reason for issuing IN 86-108 Supplement 1 in April 1987, and the Salem 2 event in August 1987 was the major reason for issuing IN 86-108, Supplement 2 in November 1987. Both of these events and their lessons learned from 1987 should have been an indicator to DBNPS that RPV wastage from boric acid accumulation was possible, and should have been included in their Boric Acid Corrosion Control (BACC) program. Information gained through interviews of engineers and managers at DBNPS (also the NRC), indicated that a mind set had developed that boric acid corrosion on the RPV head was not a credible event because of its elevated temperature.

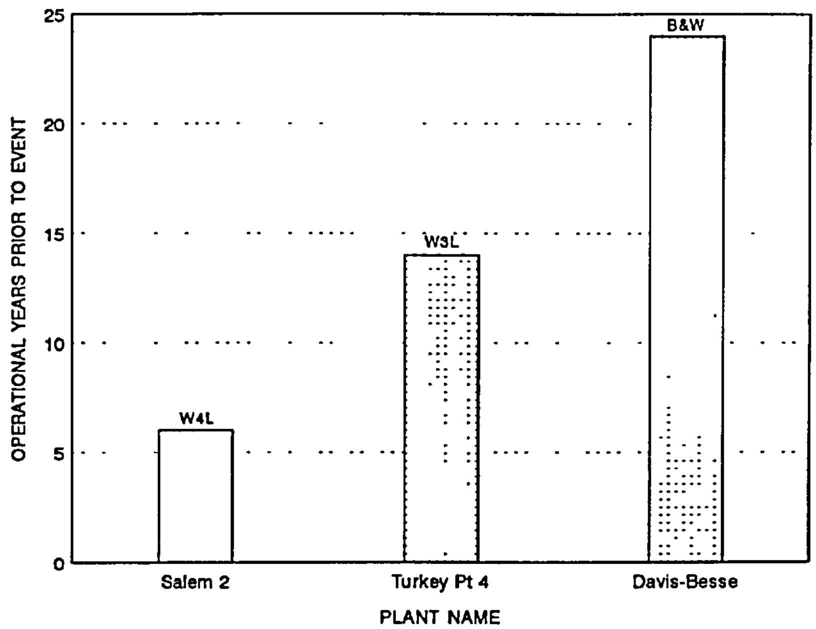

Figure 7. Reactor Pressure Vessel Head Base Metal Wastage Events

2.9 Pressurizer Vessel Wastage Events Caused by Boric Acid Corrosion

Figure 8, "Pressurizer Vessel Base Metal Wastage Events," shows those plants which have experienced corrosion (beyond surface metal corrosion). The figure also shows the number of operating years prior to event occurrence. These events and their lessons learned in conjunction with RPV wastage events do indicate that boric acid corrosion of high temperature components is possible, and should be assessed.

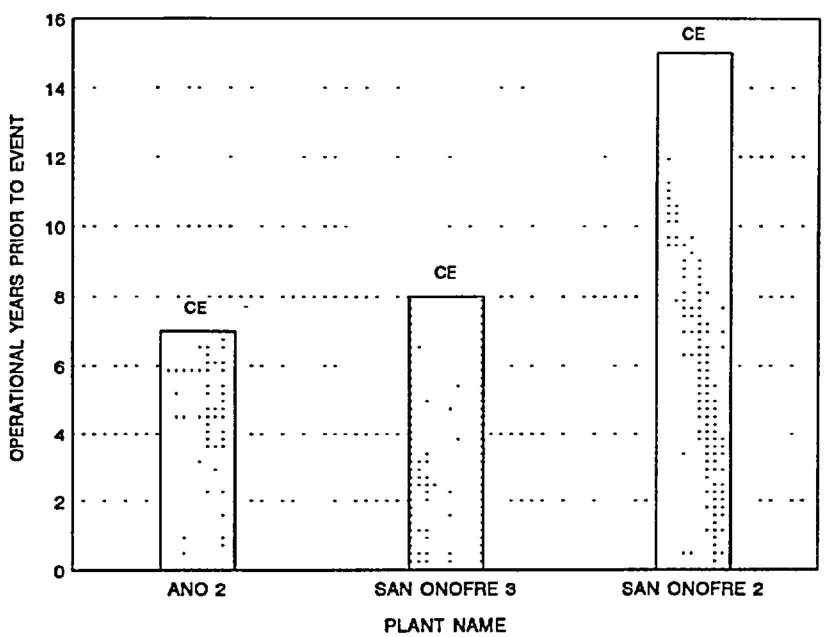

Figure 8. Pressurizer Vessel Base Metal Wastage Events

2.10 Reactor Coolant System Nozzle Leakage Operational Experience

Miscellaneous RCS nozzle leakage has occurred in varied locations. Figure 9, "Reactor Coolant System Nozzle Leakage Events," shows that the larger nozzles take longer to develop leakage. The figure would also show that no one Nuclear Steam System Supplier (NSSS) vendor dominates. Repetitive leakage from similar components is not evident.

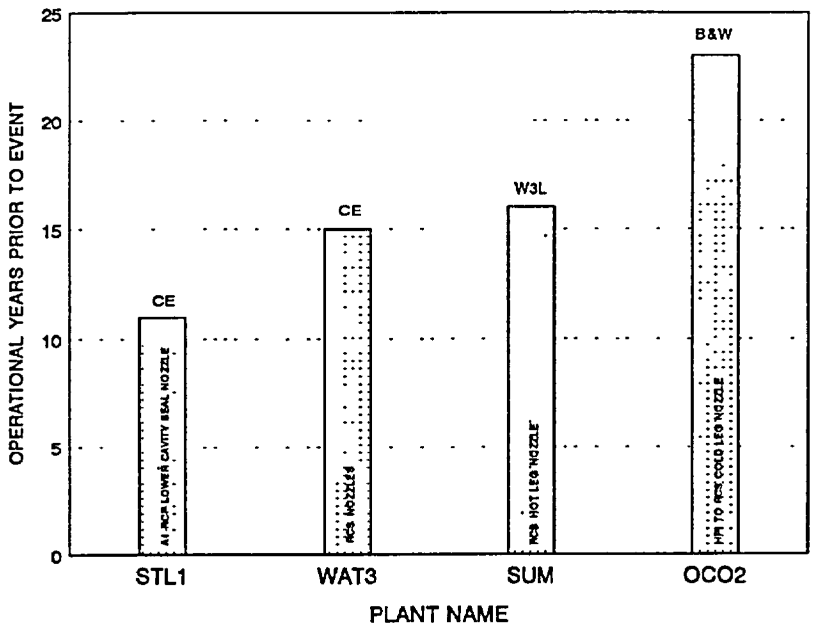

Figure 9. Reactor Coolant System Nozzle Leakage Events

2.11 Westinghouse Plants Dominate Reactor Coolant System Instrumentation Leakage

Although RCS instrumentation leakage has occurred at B&W and CE designed plants, Westinghouse plants dominated with five out of seven recorded events. Once again, the recorded events do not show indications of repetitive failures of similar components Two of the events occurred on Westinghouse three loop plants, while three events occurred on Westinghouse four loop plants. See Figure 10, "Reactor Coolant System Instrumentation Leakage" for a brief description of the event and the number of years of operation prior to each event Of note, is that five of the seven events occurred after 15 to 20 years of operation.

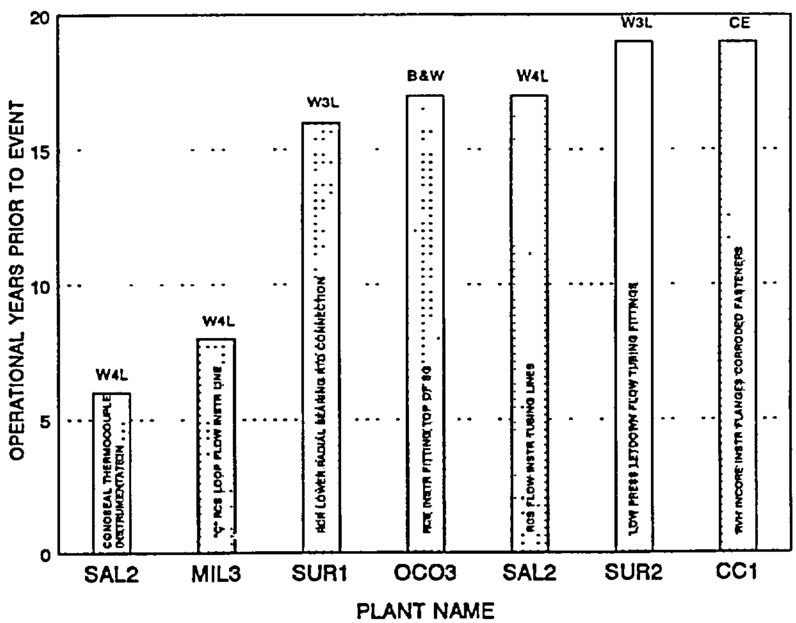

Figure 10. Reactor Coolant System Instrumentation Leakage

2.12 Combustion Engineering Plants dominate Pressurizer Instrumentation Nozzle Leakage

As shown in Figure 11, "Pressurizer Instrumentation Nozzle Leakage," CE plants dominate the recorded events. Seven of nine pressurizer instrumentation nozzle leakage events occurred at CE plants. Most of the events involved pressurizer level instrumentation. Most (5 of 8) of the pressurizer instrumentation events occurred between 11 and 14 years of operation.

2.13 Combustion Engineering Plants Accounted for All Reported Pressurizer Heater Sleeve Leakages

Figure 12, "Pressurizer Heater Sleeve Leakage," shows a dominance by CE plants with 100 percent (7 of 7) of the events. The event occurring at Calvert Cliffs 2 was extensive, involving 28 of 120 leaking sleeves. Leaking boric acid from the Calvert Cliffs event also resulted in corrosion damage to the carbon steel base metal of the pressurizer. Other events involving pressurizer heater sleeves were less severe and involved one or two sleeves

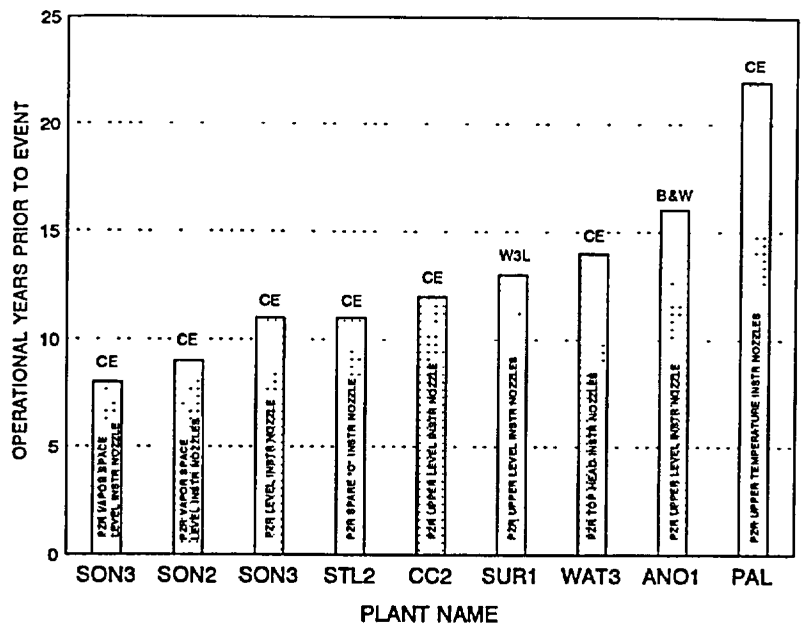

Figure 11. 'Pressurizer Instrumentation Nozzle Leakage

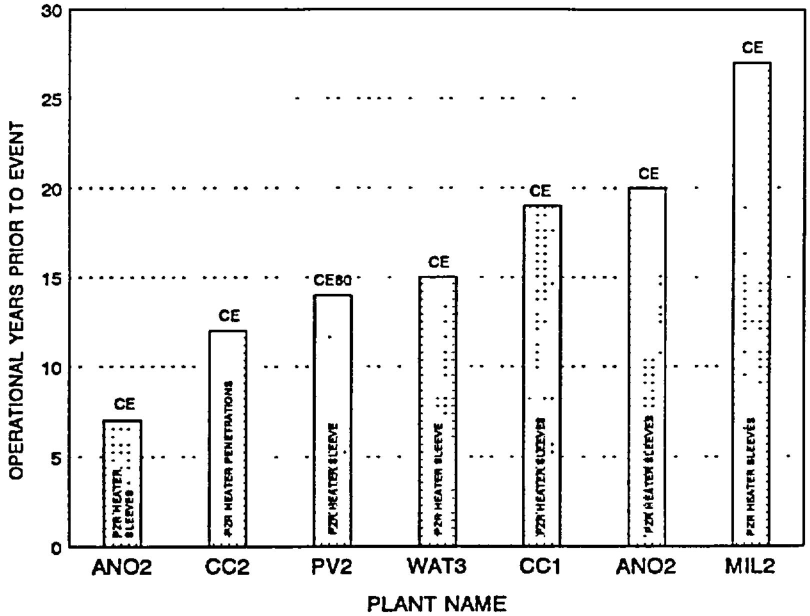

Figure 12. Pressurizer Heater Sleeve Leakage

2.14 Combustion Engineering Dominates Reactor Coolant System Instrumentation Nozzle Leakage

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As shown in Figure 13, "Reactor Coolant System Instrumentation Nozzle Leakage Events," CE dominates with 10 of 13 events. In addition, most of the events involved more than one leaking nozzle. The review also shows that most of the events involved hot leg nozzles. Nine of the 13 instrumentation nozzles occurred between 11 and 16 years of operation. Most of the nozzle cracking was attributed to primary water stress corrosion cracking (PWSCC).

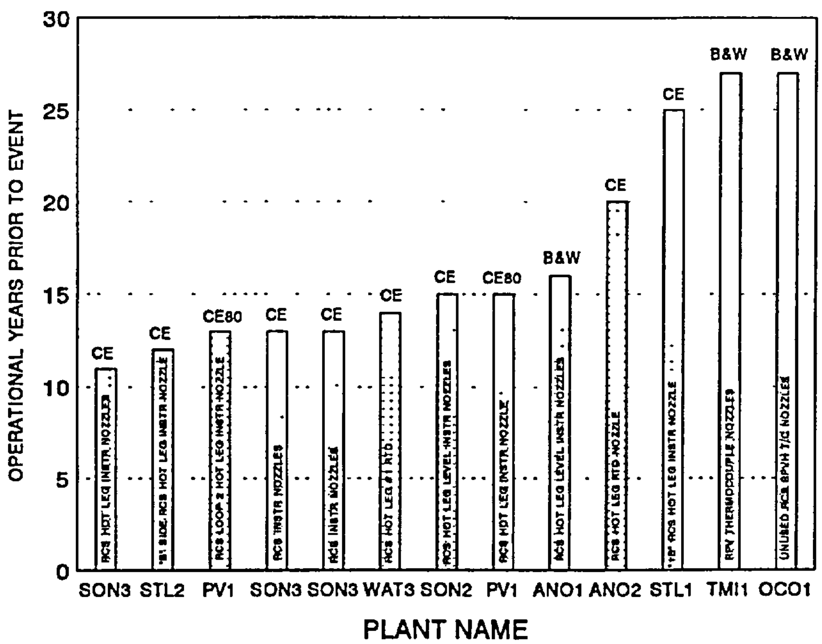

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Figure 13 Reactor Coolant System Instrumentation Nozzle Leakage Events

3.0 OPERATIONAL EXPERIENCE INFORMATION AND GUIDANCE PRESENTED THROUGH THE NRC GENERIC COMMUNICATION SYSTEM

Seventeen NRC Generic Communication documents have been issued (including supplements) by the NRC involving boric acid leakage or corrosion caused by boric acid deposits from 1980 through the first quarter of 2002. All of these documents (Information Notices, Bulletins, and Generic Letters) were issued to provide information to the industry and the public concerning recent events of interest. Some of the NRC generic communication documents (bulletins and generic letters) may have also requested that the addressees provide the NRC with requested information regarding plant specific conditions at their facilities, the existence (or non-existence) of certain programs, corrective action implementation status, and inspection status and findings. Many of the issued generic communications have alerted DBNPS and the industry to conditions that ultimately resulted in the severe corrosion of the RPV head at DBNPS over the last few years, and eventually discovered in February 2002.

3.1 An Abundance of NRC Generic Communications Involving Boric Acid Leakage or Boric Acid Corrosion Was Available

Sufficient information was issued by the NRC to alert licensees and the NRC to the potential for boric acid corrosion of carbon steel components. Numerous events have occurred since the early 1980s involving primary coolant leakage in PWRs. The primary system leaks occurred because of component failures involving material wastage by boric acid, or through stress corrosion cracking of materials and then subsequent material corrosion by boric acid. Some of these events formed the basis for NRC generic communications.

Table 2, "NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002," provides critical operating experience information relevant to boric acid leakage and corrosion. The information was provided or was available to DBNPS, however, DBNPS failed to take action and learn from their own past experiences or operating experience of other nuclear facilities. Similarly, since the NRC had issued many generic communications (INs, bulletins, and generic letters) concerning boric acid leakage and corrosion, and had also issued studies on CRDM nozzle cracking, primary system leakage, and boric acid corrosion, there was also failure of the NRC to adequately integrate its own information, and to use that operating experience information in the decision making process.

3.1.1 NRC Does Not Require an Assessment of Generic Communication Implementation by Licensees for Bulletins, Generic Letters, or Information Notices.

(1) Followup inspections and assessments performed by the NRC for bulletins and generic letters involving VHP nozzle cracking, boric acid leakage, and boric acid corrosion include the following:

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- Generic Letter 88-05 (boric acid corrosion). There was no followup inspection.

- Generic Letter 97-01 (degradation of VHP nozzles). There was a followup inspection for but it consisted of a programmatic audit of 10 facilities.

- There was a temporary instruction for Bulletin 2001-01 (RPV head degradation and reactor coolant pressure boundary integrity) but it did not address boric acid corrosion issues

(2) The most likely course of action for the NRC to take in verifying licensee action in response to a bulletin or generic letter would be through the issuance of a temporary instruction (TI). The TI is generally issued to allow the NRC regions to perform information gathering inspections, and is generally performed on a sampling basis. The current and previous NRR procedures for closeout of a bulletin or generic letter provide similar instruction.

* For NRC Bulletins and Generic Letters, NRC Inspection Manual Chapter (MC) 0720, "NRC Generic Communications" states that·

> The lead technical contact or the appropriate project manager will evaluate each addressee response for timeliness, completeness, and technical adequacy... The regions need not review the responses unless the staff issues a temporary instruction pertaining to the bulletin or generic letter... If the staff finds a reply to be inadequate, the lead technical contact or the appropriate project manager will prepare a request for additional information to be transmitted to the addressee by the appropriate project manager... After reviewing all of the bulletin or generic letter responses, and applicable safety evaluation reports, inspection reports, and regional summaries, the lead technical contact or the NRR lead project manager will compile the results and publish an internal memorandum to provide the status of each facility, the outstanding items that require additional actions, the persons responsible to perform these actions, and recommendations for additional actions by other NRC offices. The review may also be documented in a NUREG-type report.

* NRR Office Instruction LIC-503, "Generic Communication Affecting Nuclear Reactor Licensees," states that:

> The lead technical contact or the appropriate project manager will evaluate, with the help of a consultant or technical staff, as appropriate, each addressee response for timeliness, completeness, and technical adequacy. (In some cases, the staff will issue special evaluation instructions that may require establishing evaluation teams composed of personnel from the regions or headquarter or both The staff will identify such cases in a temporary instruction pertaining to the bulletin or generic letter.) ... The regions need not review the responses unless the staff issues a temporary instruction pertaining to the bulletin or generic letter...

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If the staff finds a reply to a bulletin or generic letter to be inadequate, the lead technical contact or the appropriate project manager will prepare a request for additional information to be transmitted to the addressee by the appropriate project manager... A temporary instruction (TI) is a temporary inspection procedure that, for example, may be used by NRR staff to obtain the support of NRC regional offices in verifying licensee responses to a generic communication (bulletin or generic letter), for the purpose of closing out the generic communication An assessment of the need for a TI should be made at the time authorization is sought to prepare the generic communication.

* Information Notices do not request information or require action. LIC-503 states that.

An information notice is primarily used to inform the nuclear industry of recently-identified, significant operating experience that may have generic applicability. Licensees are expected to review the information for applicability to their facilities or operations and consider actions, as appropriate, to avoid similar problems. An information notice may not convey or imply new requirements or new interpretations, and may not request information or action.

Table 2. NRC Generic Communications Involving Boric Acid Leakage and Corrosion Issued from 1980 Through the First Quarter of 2002

Generic Com	Title	Issue Date	Abstract	Licensee Requests
IN 80-27	Degradation of Reactor Coolant Pump Studs	6/11/80	Corrosion damage to a number of closure studs in two of the four Byron Jackson RCPs at Fort Calhoun (FTC) Cause of the wastage is thought to be corrosive attack by hot boric acid from the primary coolant. The condition of the studs discovered at FTC raises concerns that such severe corrosion, if undetected, could led to stud failures which could result in loss of integrity of the reactor coolant pressure boundary The lack of effectiveness of current UTs in revealing wastage emphasizes the need for supplemental visual inspections and use of instrumented leak detection systems to preclude unacceptable stud degradation going undetected Licensees should consider that the potential for undetected wastage of carbon steel bolting by a similar mechanism could exist in other components such as valves	None required
IN 82-06	Failure of Steam Generator Primary Side Manway Closure Studs	3/12/82	At Maine Yankee, 6 of 20 manway closure studs failed an another 5 were found by UT to be cracked Boric acid from a small leak was the cause Reference was made to similar events at Calvert Cliffs, FTC, Oconee, and ANO-1	None required

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BL 82-02	Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants	6/2/82	Recaps the FTC and Maine Yankee bolting problems in IN 80 27 and IN 82-06 Adds that certain lubricants may promote stress corrosion cracking At the present time visual examination (e.g IWA 2210, VT VT 1) appears to be the only method to detect borated water corrosion wastage or erosion-corrosion damage and may require insulation removal and/or disassembly of the component, in some cases, in order to have direct visual access to the threaded fasteners.	1 Develop and implement procedures for threaded fasteners practices 2 Threaded fasteners of closure connections, identified in the scope of this bulletin, when opened for component inspection or maintenance shall be removed cleaned, and inspected per IWA-2210 and IWA 2220 of ASME Code Section XI before being reused 3a Identify those bolted closures of the RCP B that have experienced leakage particularly those locations where leakage occurred during the most recent plant operating cycle Describe the inspections made and corrective measures taken to eliminate the problem If the leakage was attributed to gasket failure or its design so indicate 3b Identify those closures and connections, if any where fastener lubricants and injection sealant materials have been or are being used and report on plant experience with their application particularly any instances of SCC of fasteners Include types and composition of materials used 4 A written report to the Regional office within 60 days following the completion of the outage during which Action Item 2 was performed (4a) A statement that Action Item 1 has been completed (4b) Identification of the specific connections examined as required by Action Item 2. (4c) The results of examinations performed on the threaded fasteners as required by Action Item 2 If no degradation was observed for a particular connection a statement to that effect identification of the connection and whether the fasteners were examined in place or removed is all that is required If degradation was observed the report should provide detailed information 5 A written report to the Regional office within 60 days of the date of this bulletin The report is to provide the information requested by Action Item 3
IN 86-108	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	12/29/86	Alert recipients of a severe instance of boric acid induced corrosion of ferritic steel components in the reactor coolant system. In October 1986 ANO-1 discovered the wastage of the exterior of the HPI nozzle and some wastage of the RCS cold leg pipe (upon removal of insulation) Leakage of RCS from a leaking HPI valve which was above the nozzle and pipe The corrosion was approximately 1/4 inch deep Boric acid corrosion has been found to be most active where the metal surface is cool enough so that it is wetted If the metal is sufficiently hot, then the surface will stay dry and this loss of electrolyte will slow the corrosion rate.. Boric acid corrosion rates in excess of 1 inch depth per year in ferritic steels have been experienced in plants and duplicated in laboratory tests where low quality steam from borated reactor coolant impinged upon a surface and kept it wetted	None required
IN 86-108 Supplement 1	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	4/20/87	On 3/13/87 Turkey Pt. 4 discovered more than 500 # of boric acid crystals on the RV head There also was a large amount of boric acid crystals in the exhaust cooling ducts for the control rod drive mechanisms After removal of this boric acid and steam cleaning of the RV head, severe corrosion of various components on the RV head was noted This event has once again demonstrated that boric acid will rapidly corrode ferritic steel components and it also again demonstrated that if a small leakage occurs near hot surfaces and/or surroundings then the boric acid solution will boil and concentrate becoming more acidic and thus more corrosive On 3/13/87 Westinghouse the NSSS vendor completed a review of boric acid corrosion rates as earlier requested by the licensee and reported that the corrosion rate might be much faster than assumed when the licensee's evaluation was performed Reference was made to experience in Europe for a PWR in 1970 which experienced high corrosion rates for boric acid induced corrosion Three RV head bolts, the CRDM cooling shroud were replaced because of corrosion.	None required

IN 86-108 Supplement 2	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	11/19/87	Two events are presented Following shutdown of Salem 2 on 8/7/87 inspection teams entered containment building to look for reactor coolant leaks that would account for the increased radioactivity in containment air that was noted before the shutdown Boric acid crystals were found on a seam in the ventilation cowling surrounding the reactor head area The licensee then removed some of the cowling and insulation and discovered a mound of boric acid residue at one edge of the reactor vessel head A pile of rust-colored boric acid crystals 3 feet by 5 feet by 1 foot high had accumulated on the head and a thin white film of boric acid crystals had coated several areas of the head and extended 1 to 2 feet up the control rod mechanism housings. The source of the leak was the thermocouple instrumentation pinhole leaks Nine corrosion pits in the vessel head were found The pits were 1 to 3 inches in diameter and 0 4 to 0.36 inches deep While attempting to open a shutdown cooling valve at San Onofre 2 on 8/31/87 the packing area came apart (fasteners corroded by boric acid) and eventually dumped 18,000 gallons of reactor coolant in to the containment Westinghouse reported that boric acid corrosion rates are greater than those that were either previously known or estimated	None required
IN 86-108 Supplement 3	Degradation of Reactor Coolant System Pressure Boundary Resulting From Boric Acid Corrosion	1/5/95	Presents two additional events involving boric acid corrosion Calvert Cliffs 1 (2/94) and TMI1 (3/7/94) In 2/94 Calvert Cliffs 1 (CC1) found three nuts on an incore instrumentation flange that were corroded by boric acid resulting in a leak. During a subsequent inspection three more nuts on another incore instrumentation flange were also corroded by the same mechanism On 3/7/94 and while a 100 % power TMI1 was trying to eliminate a leak of a pressurizer spray valve by tightening a bonnet stud when the leak suddenly increased to 3 gpm Other studs completely failed CC1 thought that the corrosion rate from the leakage was acceptably low in 5/93, and elected to defer the corrective actions for the flanges until the 1994 refueling outage Other parts of the IN recap earlier problems with boric acid corrosion	None required
GL 88-05	Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants	3/17/88	The principal concern is whether the affected plants continue to meet the requirements of GDC 14, 30 and 31 of Appendix A when the concentrated boric acid solution or boric acid crystals, formed by evaporation of water from the leaking reactor coolant corrode the reactor coolant pressure boundary The GL cites Turkey Pt 4 Salem 2, San Onofre 2, ANO-1 and FTC The GL cites BL 82 2 as not requiring the licensees to institute a systematic program for monitoring small primary coolant leakages and to perform maintenance before leakages could cause significant corrosion damage Because of this deficiency in the BL the GL requests 4 actions to be taken by licensees	(1) Determine the principal locations where leaks that are smaller than the allowable TS limit can cause degradation of the primary pressure boundary by boric acid corrosion (2) establish procedures for locating small coolant leaks (3) establish methods for conducting examinations and performing engineering evaluations once a leak is located and (4) corrective actions to prevent recurrence of this type of corrosion Responses are required within 60 days of the date of the GL.
IN 90-10	Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600	2/23/90	Alert licensees to potential problems related to PWSCC of Inconel 600 that has occurred in pressurizer heater thermal sleeve and instrument nozzles at several domestic and foreign PWR plants During the 1989 refueling outage at CC2 visual examination detected leakage in 20 pressurizer heater penetrations and 1 upper level pressure tap instrument nozzle Leakage was indicated by the presence of boric acid crystals The heater sleeves and the instrumentation nozzles were made of Inconel 600 tubing and bar materials, respectively supplied by INCO All instrument nozzles were made from heat no NX8297 On 2/27/86 a small leak was observed on a 3/4 inch diameter upper pressurizer level instrument nozzle at SONGS 3 Two foreign reactors were also cited involving Inconel 600 PWSCC was first reported by Coriou almost 30 years ago The studies of PWSCC in Inconel 600 have been documented in numerous reports however the mechanism for PWSCC in Inconel 600 is still not well understood It may be prudent for licensees of all PWRs to review their Inconel 600 applications in the primary coolant pressure boundary and when necessary to implement an augmented inspection program.	None required

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IN 94-63	Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks	8/30/94	Alert licensees to the potential for significant damage that could result from corrosion of reactor system components caused by cracking of the stainless steel cladding Severe corrosion damage of the carbon steel casing of a high head safety injection pump at North Anna 1 The damage was caused by cracks through the stainless steel cladding in the pump that allowed corrosive attack by the boric acid coolant The corrosion had penetrated to within about 0 125 inch of the outside surface of the pump (2.5 inches long by 1 5 inches wide by 0.5 inches deep)	None required
IN 96-11	Ingress of Demineralizer Resins Increases Potential for Stress Corrosion Cracking of Control Rod Drive Mechanism Penetrations	2/14/96	Alert licensees to the increased likelihood of stress corrosion cracking of PWR control rod drive mechanism penetrations if demineralizer resins contaminate the reactor coolant system. The NRC determined that the safety significance of the cracking was low because the cracks were axial had a low growth rate and were in a material with an extremely high flaw tolerance (high fracture toughness) Accordingly the cracks were unlikely to propagate very far In December 1991 after cracks were found in a CRDM penetration in the reactor head at a French plant (Bugey 3) an NRC action plan was implemented to address PWSCC at all U S plants. The NRC asked the Nuclear Management and Resources Council (NEI) to coordinate future industry actions because the issue was applicable to all PWRs. Each owners group submitted individual safety assessments, dated February 1993, through NEI to the NRC on the CRDM cracking issue In July 1993 the NEI submitted to the NRC proposed acceptance criteria for flaws identified during inservice examination of CRDM penetrations On the basis of owners group analyses and the European experience the NRC concluded that there was a high probability that CRDM penetrations at U S plants may contain similar axial cracks caused by PWSCC In 1994 an inspection for PWSCC at a reactor in Spain identified cracks which were apparently initiated by high sulfate levels in the reactor coolant system 16 of 17 spare penetrations showed stress corrosion cracking and 4 of 20 active penetrations showed stress corrosion cracking	None required

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GL 97-01	Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations	4/1/97	This GL requests licensees (1) to describe their program for ensuring the timely inspection of PWR control rod drive mechanism and other vessel closure head penetrations and (2) require that all addresses provide to the NRC a written response to the requested information Beginning in 1986, leaks have been reported in several Alloy 600 pressurizer instrument nozzles at both domestic and foreign reactors from several different NSSS vendors. In 1989 PWSCC was an emerging technical issue after cracking was noted in Alloy 600 pressurizer heater sleeve penetrations at a domestic facility The NRC staff determined that the cracking was not of immediate safety significance because the cracks were axial had a low growth rate were in a material with an extremely high flaw tolerance (high fracture toughness) and accordingly were unlikely to propagate very far These factors also demonstrated that any cracking would result in detectable leakage and the opportunity to take corrective action before a penetration would fail European and Japanese utilities have taken steps to detect and mitigate the PWSCC damage and to detect the leakage at an early stage European and Japanese utilities have inspected most of the CRDM nozzles and repaired the nozzles or replaced the vessel heads as appropriate In Japan the three most susceptible vessel heads are being replaced even though no cracks were found in the nozzles of these heads In France Electricite de France (EDF) is planning on replacing all vessel heads as a preventative measure Removable insulation on the vessel head and leakage monitoring systems are installed at French and Swedish plants for early detection of leakage The NRC staff concluded that VH penetration cracking does not pose an immediate or near term safety concern A 11/19/93 NRC safety evaluation is referenced which states that the staff recommends that NUMARC (NEI) consider enhanced leakage detection by visually examining the reactor vessel head until either inspections have been completed showing absence of cracking or on-line leakage detection is installed in the head area The staff believes that it is prudent for NUMARC (NEI) to consider the implementation of an enhanced leakage detection method for detecting small leaks during plant operation On 3/5/96 NEI submitted a white paper entitled "Alloy 600 RPV Head Penetration Primary Stress Corrosion Cracking " which reviewed the significance of PWSCC in PWR VH penetrations and describes how the industry is managing the issue The program outlined in the NEI paper is based on the assumption that the issue is primarily an economic rather than a safety issue and describes an economic decision tool to be used by PWR licensees to evaluate the probability of a VH penetration developing a crack or a through-wall leak during a plant's lifetime	Regarding inspection activities. 1 1 A description of all inspections of CRDM nozzle and other VH penetrations performed to the date of this generic letter including the results of these inspections 1.2 If a plan has been developed to periodically inspect the CRDM nozzle and other VH penetrations a) provide the schedule for first, and subsequent inspections of the CRDM nozzle and other VH penetrations, including the technical basis for this schedule b) provide the scope for the CRDM nozzle and other VH penetration inspections including the total number of penetrations (and how many will be inspected) which penetrations have thermal sleeves which are spares and which are instrument or other penetrations 1 3 If a plan has not been developed to periodically inspect the CRDM nozzle and other VH penetrations described above provide the analysis that supports the selected course of action as listed in either 1 2 or 1.3 above In particular provide a description of all relevant data and/or tests used to develop crack initiation and crack growth models the methods and data used to validate these models the plant specific inputs to these models and how these models substantiate the susceptibility evaluation Also If an integrated industry inspection program is being relied on provide a detailed description of this program 2 Provide a description of any resin bead intrusions, as described in IN 96-11 that have exceeded the current EPRI PWR Primary Water Chemistry Guidelines recommendations for primary water sulfate levels including the following information 2 1 Were the intrusions cation anion or mixed bed? 2.2 What were the durations of these intrusions? 2.3 Does the plant's RCS water chemistry Technical Specifications follow the EPRI guidelines? 2.4 Identify any RCS chemistry excursions that exceed the plant administrative limits for the following species. sulfates chlorides or fluorides oxygen, boron, and lithium 2.5 Identify any conductivity excursions which may be indicative of resin intrusions. Provide a technical assessment of each excursion and any followup actions Respond within 30 days 2 6 Provide an assessment of the potential for any of these intrusions to result in a significant increase in the probability for IGA for VH penetrations an any associated plan for inspections
IN 2001-05	Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station Unit 3	4/30/01	Alert licensees to the recent detection of through-wall circumferential cracks in two of the control rod drive mechanism penetration nozzles and weldments at the Oconee Nuclear Station Unit 3 The circumferential crack in the #56 CRDM nozzle was through-wall and the #50 nozzle had pin hole through-wall indications These cracks followed the weld profile contour and were nearly 165 degrees in length Root cause of the cracking was PWSCC The nozzles were shrink fit by cooling to at least minus 140 degrees F inserted into the closure head penetration, and then allowed to warm to room temperature (70 degrees F minimum) The CRDM nozzles were tack-welded and then permanently welded to the closure head using 182-weld metal The recent identification of significant circumferential cracking of two CRDM nozzles at Oconee 3 raises concerns about a potentially risk-significant condition affecting all domestic PWRs. Further the environment in the CRDM housing annulus will likely be far more aggressive after any through-wall leakage because potentially highly concentrated borated primary water will become oxygenated increasing crack growth rates. The Oconee 3 cracking reinforces the importance of examining the upper PWR RPV head area (e g. visual under-the-insulation examinations of the penetrations for evidence of borated water leakage or volumetric examinations of the CRDM nozzles) and of using appropriate NDE methods to adequately characterize cracks	None required

BL 2001-01	Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles	8/3/01	The purpose of the bulletin is to request that addresses provide information related to the structural integrity of the reactor pressure vessel head penetration nozzles for their respective facilities, including the extent of VHP nozzle leakage and cracking that has been found to date the inspections and repairs that have been undertaken to satsfy applicable regulatory requirements and the basis for concluding that their plans for future inspections will ensure compliance with applicable regulatory requirements, and require that all addresses provide to the NRC a written response The Bulletin recaps thru-wall circumferential cracking experienced at Oconee 3 As a remedial measure the RPV head may have to be cleaned at a prior outage for effective identification of new deposits from VH penetration nozzle cracking if new deposits cannot be discriminated from existing deposits from other sources The recently identified CRDM nozzle degradation phenomena raise several issues regarding the resolution approach taken in GL 97-01 1) Cracking of Alloy 182 weld metal has been identified in CRDM nozzle J-groove welds for the first time The finding raises an issue regarding the adequacy of cracking susceptibility models based only on the base metal conditions 2) Cracking at ANO 1 raises an issue regarding the adequacy of the industry's GL 97-01 susceptibility model. 3) Circumferential cracking of CRDM nozzles, located outside of any structural retaining welds has been identified for the first time This concern raises concerns about the potential for rapidly propagating failure of CRDM nozzles and control rod ejection causing a loss of coolant accident 4) Circumferential cracking from the CRDM nozzle OD to the ID has been identified for the first time This finding raises concerns about increased consequences of secondary effect of leakage from relatively benign axial cracks 5) Circumferential cracking of CRDM nozzles was identified by the presence of relatively small amounts of boric acid deposits This finding increases the need for more effective inspection methods to detect the presence of degradation in CRDM nozzles before the nozzle integrity is compromised The Bulletin cites several GDC criteria (14 31 32) 10CFR50.55a and Appendix B Criteria V IX, and XVI that may not be fully adhered to	Requests the following 1 All addressees. 1a) the plant-specific susceptibility ranking using the PWSCC susceptibility model described in Appendix B to the MRP-44 Part 2 report 1b) a description of the VH penetration nozzles, including the number type inside and outside diameter, materials of construction and the minimum distance between VH penetration nozzles 1c) a description of the RPV head insulation type and configuration, 1d) a description of the VH penetration nozzle and RPV head inspections (type scope qualification requirement, ad acceptance criteria) that have been performed in the past 4 years and the findings Include a description of any limitations (insulation or other impediments) to accessibility of the bare metal of the RPV head for visual examinations. 2 If your plant has previously experienced either leakage from or cracking in VH penetration nozzles, provide the following 2a) a description of the extent of VH penetration leakage and cracking including the number location, size and nature of each crack detected 2b) a description of the additional or supplemental inspections (type scope qualification requirements, and acceptance criteria) repairs and other corrective actions you have taken in response to identified cracking to satisfy applicable regulatory requirements 2c) plans for future inspections (type scope qualification requirements, and acceptance criteria) and the schedule 2d) basis for concluding that the inspections identified in 2c will assure that regulatory requirements are met. Include the following 2d(1) If your future inspections plans do not include performing inspections before 12/31/01, provide your basis for concluding that the regulatory requirements will continue to be met until the inspections are performed 2d(2) If your future inspection plans do not include volumetric examination of all VH penetration nozzles, provide your basis for concluding that the regulatory requirements will be satisfied 3) If the susceptibility ranking for your plant is within 5 EFPY of ONS3 addresses are requested to provide the following 3a) plans for future inspections and the schedule 3b) basis for concluding that the inspections identified in 3a will assure that regulatory requirements are met Include the following specific information 3b(1) If your future inspection plans do not include performing inspections before 12/31/01, provide your basis for concluding that the regulatory requirements will continue to be met until the inspections are performed 3b(2) If your future inspection plans include only visual inspections, discuss the corrective actions that will be taken including alternative inspection methods if leakage is detected 4 If the susceptibility ranking for your plant is greater than 5 EFPY and less than 30 EFPY of ONS3 addressees are requested to provide the following: 4a) plans for future inspections and schedule 4b) basis for concluding that the inspections identified in 4a will assure that regulatory requirements are met Include the following specific information 4b(1) If your future inspection plans to not include a qualified visual examination at the net scheduled refueling outage provide your basis for concluding that the regulatory requirements will continue to be met until the inspections are performed 4b(2) Corrective actions that will be taken, including alternative inspection methods if leakage is detected 5) Addressees are requested to provide the following information within 30 days after plant restart following the next refueling outage 5a) a description of the extent of VH penetration nozzle leakage and cracking detected at your plant including the number location size and nature of each crack detected, 5b) if cracking is identified a description of the inspections repairs and other corrective actions you have taken to satisfy applicable regulatory requirements This information is requested only if there are any changes from prior information submitted.

IN 2002-11	Recent Experience with Degradation of Reactor Pressure Vessel Head	3/12/02	To inform addressees about findings from recent inspections and examinations of the reactor pressure vessel head at Davis-Besse Nuclear Power Station. Recaps previous generic communication information about boric acid on the RPV head at Davis-Besse Visual inspections in 1998 showed an even layer of boric acid deposits scattered over the RPV head (including deposits near CRDM nozzle 3) This indicated to the licensee that the boric acid evident on the head flowed downward from leakage in the CRDM flanges During a refueling outage in 2000 the licensee also performed visual inspections of the CRDM flanges and nozzles. Above the RPV head insulation, those inspections revealed five CRDM flanges with evidence of leakage including one flange that was the principal leakage point All of the leaking flanges were repaired by replacing their gaskets Visual inspections performed below the RPV head insulation during the 2000 refueling outage indicated some accumulation of boric acid deposits on the RPV head No visible evidence of CRDM nozzle leakage (I.e leakage from the gap between the nozzle and the RPV head) was detected The licensee described that the RPV head area was cleaned with demineralized water to the greatest extent possible while trying to maintain the dose as low as reasonably achievable (ALARA) Subsequent video inspection of the partially cleaned RPV head and nozzles was performed for future reference A subsequent review of the 1998 and 2000 inspection video tapes in 2001 confirmed that there was no evidence of leakage from the RPV head nozzles, although many areas of the RPV head were not accessible because of persistent boric acid deposits that the licensee did not clean because of ALARA issues (including the region around nozzle 3). The inspections in 2002 did not reveal any visual evidence of flange leakage from above the RPV head However three CRDM nozzles had indications of cracking (identified by ultrasonic testing of the nozzles), which could result in leakage from the RPV to the top of the RPV head	None required
BL 2002-01	Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity	3/18/02	The purpose of the bulletin is to require PWR addressees to submit (1) information related to the integrity of the reactor pressure boundary including reactor pressure vessel head and the extent to which inspections have been undertaken to satisfy applicable regulatory requirements and (2) the basis for concluding that plants satisfy applicable regulatory requirements related to the structural integrity of the reactor coolant pressure boundary and future inspections will ensure continued compliance with applicable regulatory requirements and (3) a written response to the NRC if they are unable to provide the information or they can not meet the requested completion dates Recaps past generic communications and experience at Davis-Besse A past model where boric acid crystals are assumed to accumulate on the RPV head the deposits were assumed to cause minimal corrosion while the reactor was operating because the temperature of the RPV head is above 500 F during operation and dry boric acid crystals are not very corrosive Therefore wastage was typically expected to occur only during outages when the boric acid could be in solution, such as when the temperature of the RPV head falls below 212 F These findings at Davis-Besse bring into question the reliability of this model. Inspections performed to date at plants with high and moderate susceptibility have generally confirmed the ability of the model to predict a plant's relative susceptibilities, however a plant with a ranking of 14.3 effective full-power years from the Oconee 3 condition (at the time when circumferential cracking was identified at Oconee 3 in March 2001) identified three nozzles with cracking other plants with fewer effective full-power years from the Oconee 3 condition did not identify cracking Some inspection and repair methods may not have been capable of identifying the presence of a void in the carbon steel head adjacent to the cladding interface	1 Within 15 days of the date of the bulletin all PWR addressees are required to provide the following A) a summary of the reactor pressure vessel head inspection and maintenance programs that have been implemented at their plants, B) an evaluation of the ability of their inspection and maintenance programs to identify degradation of the RPV head including thinning pitting or other forms of degradation such as the degradation of the RPV observed at Davis-Besse C) a description of any conditions identified (chemical deposits head degradation) through the inspection and maintenance programs described in 1A that could have led to degradation and the corrective actions taken to address such conditions D) schedule plans, and basis for future inspections of the RPV head and penetration nozzles This should include the inspection method(s) scope frequency qualification requirements, and acceptance criteria and E) conclusions regarding whether there is reasonable assurance that regulatory requirements are currently being met If the evaluation does not support the conclusion that there is reasonable assurance that regulatory requirements are being met discuss plans for plant shutdown and inspection If the evaluation supports the conclusion that there is reasonable assurance that regulatory requirements are being met provide your basis for concluding that all regulatory requirements will continue to be met until the inspections are performed 2 Within 30 days after plant restart following the next inspection of the RPV head to identify any degradation, all PWR addressees are required to submit to the NRC the following information A) the inspection scope and results, including the location, size and nature of any degradation detected and B) the corrective actions taken and the root cause of the degradation 3 Within 60 days of the date of this bulletin all PWR addressees are required to submit to the NRC the following information related to the remainder of the reactor coolant pressure boundary A) the basis for concluding that their boric acid inspection program is providing reasonable assurance of compliance with the applicable regulatory requirements discussed in Generic Letter 88-05 and this bulletin If a documented basis does not exist provide your plans if any for a review of your programs. Within 7 days of the date of the bulletin a PWR addressee is required to submit a written response if they re unable to provide the information or they can not meet the requested completion dates Alternative courses of action and their basis must be provided.

IN 2002-13	Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation	4/4/02	To alert addressees to possible indicators of RPV boundary degradation including degradation of the RPV head material These indicators include unidentified reactor coolant system leakage and containment air cooler and radiation element filter fouling Containment air coolers cleaning of boron deposits greatly increased The licensee noticed that deposits removed from CAC 1 exhibited a rust-like color The licensee attributed the discoloration to migration of the surface corrosion on the CACs into the boric acid deposits and to the aging of the boric acid deposits During the 2002 outage fifteen 5-gallon buckets of boric acid were removed from the CAC ductwork and plenum A flow from the CACs also resulted in boric acid deposits elsewhere within containment including on service water piping stairwells and other areas of low ventilation The radiation element filters accumulate particulates and may need to be changed to ensure acceptable system operation Licensee records correlate RE filter changes with past RCS leakage increases In March 1999 RE filter clogging from boric acid deposits was identified and attributed to the pressurizer relief valve modification In November 1999 after identifying yellowish brown deposits in the filters the licensee obtained a chemical analysis of the filter particulates which identified the presence of ferric oxide in addition to boric acid crystals Around that time the licensee began changing the filters every one-to-three weeks. By November 1999 the frequency of filter changes had again increased	None required

3.2 Operating Experience Events and Issuance of NRC Generic Communications

Figure 14, "Boric Acid Leakage and Corrosion Events Vs Relevant NRC Generic Communication Documents," shows that several years elapsed (with relatively high numbers of primary system leakage or boric acid corrosion events) with no boric acid leakage or corrosion generic communications being issued by the NRC For example, during the period 1989 through 1994, two INs were issued (IN 90-10 on PWSCC of Inconel 600, and IN 94-63 on boric acid corrosion of a pump casing) In addition, during the period 1998-2000 there were numerous examples of RCS nozzle leaks with no generic communication being issued

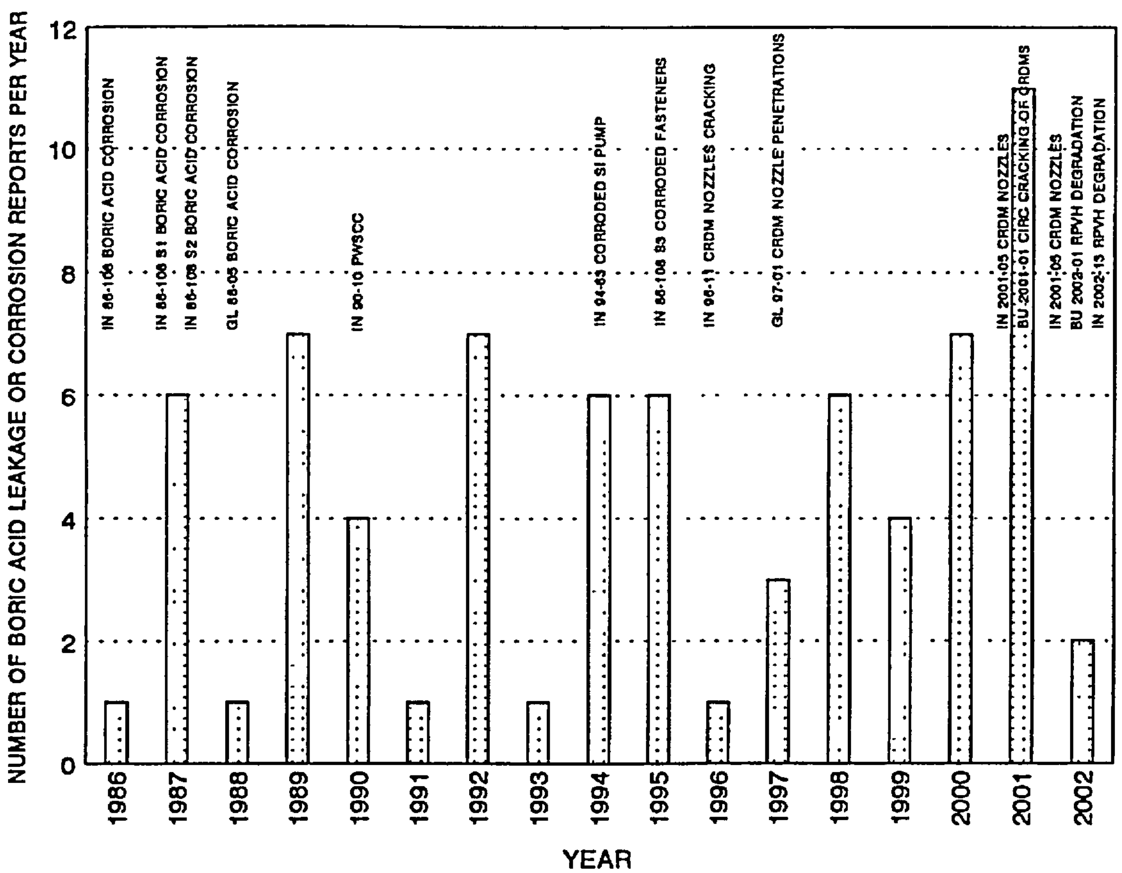

Figure 14. Boric Acid Leakage and Corrosion Events VS. Relevant NRC Generic Communication Documents

3.2.1 Boric Acid Leakage or Corrosion Events Reported from 1989 Through 1994 That Did Not Result in a Generic Communication

McGuire Unit #1 (LER #36989020). On 7/27/89, abnormal degradation of the unit 2 steel containment vessel (SCV) because of corrosion was discovered. The corrosion was caused by standing water in the annulus area. The most significant corrosion occurred in areas where boric acid deposits were also found. The boric acid deposits resulted from leaking instrumentation connections. Similar degradation was found in unit 2.

Catawba Unit #1 (LER #41389020). On 9/21/89, a preliminary visual inspection of the Catawba Units 1 and 2 SCV exterior surfaces was performed. The observed corrosion was caused by standing water in the annulus areas. The most significant corrosion occurred in areas where boric acid deposits were also found.

Arkansas Nuclear Unit #1 (LER #31389043). On 12/8/89, while removing the nut ring from

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beneath the reactor vessel nozzle flange at control rod drive mechanism (CRDM) location I-2, it was discovered that approximately 50% of one of the nut ring halves had corroded away and that two of the four bolt holes in the corroded nut ring half were degraded to the point where there was no bolt/thread engagement.

Millstone Unit #3 (LER #42389031) On November 28, 1989, a loose nozzle ring set screw on the 'C' pressurizer safety valve was found with steam discharging from the set screw location. The nozzle ring, which is held in place by the set screw, is essential in assuring the valve pops fully open. An inspection of the valve revealed that the set screw threads were corroded (by boric acid) or steam cut.

Ft. Calhoun Unit #1 (LER #28592018). On March 20, 1992, severe corrosion of the carbon steel fasteners on the boric acid pump flanges and piping supports was discovered The root cause of this event was the original design of the flange connections did not anticipate corrosion problems due to boric acid leakage at the system flange connections. The carbon steel fasteners were covered with glued heat tracing and asbestos insulation, thus, sealing the fasteners in a potentially high corrosive environment.

Waterford Unit #3 (LER #38292002). On March 25, 1992, an Unusual Event was declared due to reactor coolant system leakage. The reactor was shut down and the source of the leakage was subsequently determined to be the packing area of reactor coolant hot leg sample valve RC-104. The packing gland studs on RC-104 failed due to boric acid corrosion.

Waterford Unit #3 (LER #38292006). On July 11, 1992, an Unusual Event was declared as a result of reactor coolant system leakage. The reactor was shut down and the source of the leakage determined to be the packing area of Reactor Coolant Hot Leg Sample Valve RC-104. This event resulted from the failure of a temporary leak repair made to RC-104 after the valve's packing gland studs failed due to boric acid corrosion on March 25, 1992.

Seabrook Unit #1 (LER #44392026). On July 14, 1992, it was discovered that three of the four cover bolts on Chemical Volume Control System demineralizer 2A resin sluice discharge valve, CS-V-93 had fractured. This bolting configuration caused the valve bonnet to loosen and become cocked. It was discovered that two additional valves, CS-V-252 and CS-V-742, in close proximity to CS-V-93 each had two fractured cover bolts. CS-V-93 and CS-V-252 are safety related, ASME Class 3 valves, and CS-V-742 is a non-nuclear safety valve. The root cause of the bolting failures was stress corrosion cracking. North Atlantic has replaced bolting on a total of 158 Xomox Tufline plug valves which had Grade B6 Type 410 stainless cover bolts.

Millstone Unit #3 (LER #42394012). On September 9,1994, a leak was discovered in 3/4-inch socket weld on a 'C' RCS Loop Flow Instrumentation line. The weld was removed for analysis during which liquid penetrant testing identified a circumferential crack approximately, 5/8-inch long. Initial metallurgical analysis indicated that the root cause of the socket weld failure was most probably a weld defect, believed to result from a lack of fusion in the weld root.

Calvert Cliffs Unit #1 (LER #31794003). On February 16, 1994, boron deposits were noticed on PZR heater sleeve B-3 indicating leakage from the RCS. The examination revealed a circumferential bulge approximately 0.5 inches long and 0.019 inches high (diametrical) in the area of the boric acid leaks. The most probable cracking mechanism is Primary Water Stress

Corrosion Cracking. The source of stress for the cracking was the bulging and axial scratches associated with the removal of the stuck reamer. Corrective Actions included plugging FF-1 with an Alloy 690 plug welded to the outer diameter of the PZR lower head and examining the remaining Unit 1 PZR heater sleeves.

Calvert Cliffs Unit #1 (LER #31794004). On February 21, 1994, a higher than anticipated corrosion of three nuts were discovered on one of the Incore Instrumentation flanges on the Unit 1 reactor vessel head. A subsequent inspection discovered an additional flange with similar degradation. The flanges were known to be leaking slightly since 1993, but repairs were deferred until 1994 because the expected corrosion rate was very low. The excessive corrosion rate was apparently due to the presence of wet boric acid on some of the flange components where we expected only dry boric acid.

Three Mile Island Unit #1 (LER #28994001). On March 7, 1994, TMI-1 located and isolated a body-to-bonnet leak from the pressurizer spray valve (RC-V1). The root causes was boric acid degradation of RC-V1 fasteners and the failure to consider pre-load when increasing motor operator torque. Corrective actions include an evaluation of corrosion resistant fastener materials, programmatic improvements, and training.

Diablo Canyon Unit #1 (LER #27590010). On July 31, 1990, leakage through a crack in the unit 1 positive displacement charging pump (PDP) suction piping elbow was discovered.

Calvert Cliffs Unit #2 (LER #31894003). On July 11, 1994, a non-isolable Reactor Coolant System pressure boundary leak was discovered. The leak was found to be caused by a 150 degree circumferential crack in a weld in the 22A Safety Injection Tank discharge test connection.

Oconee Unit #3 (LER #28791008). On November 23, 1991, several alarms were received which indicated failed instruments inside the reactor building. The shift supervisor concluded that leakage was approximately 60 to 70 gpm, and declared an alert. The unit tripped from 33% full power due to a control oscillation while attempting to secure a feedwater pump. The leak was determined to be a failed fitting on an instrument line at the top of a steam generator. A total of approximately 87,000 gallons of RCS leakage was confined within the reactor building.
Surry Unit #2 (LER #28192008). On December 15, 1992, an RCS leak had developed near the Low Pressure Letdown Flow Transmitter. The leakage occurred when a section of drain valve tubing for the Low Pressure Letdown Flow Transmitter separated from its fitting.

Arkansas Nuclear Unit #1 (LER #31390021). On December 22, 1990, a potential RCS leak in the area of a pressurizer upper level instrumentation nozzle was discovered. Subsequent inspection using Nondestructive Examination methods confirmed the existence of a small axial crack in the nozzle inner surface which extended to the annulus between the nozzle and the pressurizer shell and breached the outside diameter of the nozzle at the toe of the nozzle to vessel weld.

Ft. Calhoun Unit #1 (LER #28590028). On December 14, 1990, an investigation of unknown RCS leakage identified the source as installed spare control element drive mechanism (CEDM) housing number 9. Subsequent removal and inspection identified two axial cracks in an inside diameter weld overlay region approximately two feet from the bottom flange of the housing.

Similar installed spare CEDM housing number 13 was also removed and inspected, revealing two similar cracks in the weld overlay region.

Point Beach Unit #1 (LER #26690008). On July 20, 1990 unit 1 was shut down to repair leaks in the RCS with an average total leakage of approximately 0.27 gallons per minute. Reactor coolant was leaking through a canopy seal weld on CRDM I-3 and the upstream weld on B steam generator channel head drain line isolation valve 1RC-526B.

Calvert Cliffs Unit #2 (LER #31889007). On May 5, 1989, an in-service inspection of the unit 2 pressurizer discovered evidence of reactor coolant leakage from 28 of the 120 pressurizer vessel heater penetrations and one upper level nozzle. The cause of leakage was intergranular stress corrosion cracking of Inconel 600.

San Onofre Unit #2 (LER #36192004). On 2/18/92, a dye-penetrant examination of a pressurizer vapor space level instrument nozzle revealed the presence of a crack. The examination was prompted by earlier observations of rust and boric acid crystals in the vicinity of the nozzle during a walkdown of the RCS following the shutdown. A thorough inspection of the unit 2 nozzles, prompted by the findings at unit 3, revealed similar signs of rust and boric acid crystals at two of the nozzles The observed leakage was attributed to PWSCC of the Inconel 600 material.

Palisades Unit #1 (LER #25593011). On October 9, 1993, an inspection of the pressurizer upper temperature nozzle penetration (TE-0101) found it to be leaking. Subsequent inspection of the lower temperature nozzle penetration (TE-0102) found it to be leaking also. The root cause was determined to be PWSCC of the Inconel 600 nozzle material

St. Lucie Unit #2 (LER #38994002). On March 16, 1994, FPL Engineering personnel identified trace amounts of boric acid on the exterior of the pressurizer steam space C instrument nozzle during an inspection. Subsequently, an interior dye penetrant examination was performed and identified unacceptable indications at the A, B and C steam space instrument nozzle welds The unacceptable weld indications were in the 'J' weld between the alloy 690 nozzle and the clad on the inside of the pressurizer.

St. Lucie Unit #2 (LER #38995004). On October 10, 1995, an instrument nozzle located on the 'B' side RCS hot leg exhibited an apparent boric acid buildup indicative of RCS leakage. Further investigation confirmed that pressure boundary leakage had previously occurred, most probably due to PWSCC of alloy 600 material at the instrument nozzle.

3.2.2 Boric Acid Leakage or Corrosion Events Reported From 1998 Through 2000

Davis-Besse Unit #1 (LER #34698009). On September 9, 1998, two of the eight body to bonnet nuts missing on Reactor Coolant Pressurizer Spray Valve (RC-2). The most probable cause for the two missing nuts on RC-2 is that a packing leak allowed boric acid corrosion of two carbon steel nuts that were inadvertently installed on RC-2 a few months earlier, due to less than adequate material separation work practices during previous maintenance activities. These nuts were subsequently replaced on September 9, 1998, and September 10, 1998. On-line leak sealing activities were conducted on September 10, 1998, to stop the boric acid leak at RC-2. On October 16, 1998, it was discovered that the second nut, installed on September 10, 1998, was not installed properly. At this same time, it was discovered that an additional nut was degraded.

Beaver Valley Unit #2 (LER #41200003). On December 11, 2000, control room operators received indications of a primary system leak in the Reactor Containment Building. The RCS leak rate was estimated to be between 12 and 20 gpm. The cause of the RCS leakage into the containment building was an abrupt packing leak on a motor-operated drain insolation valve on the RCS. The gland stud eye bolts on the RCS primary loop fill and drain valves were replaced with a more stress corrosion resistant material.

Salem Unit #2 (LER #31198007). On July 29, 1998, indications of leakage through RCS instrumentation tubing were discovered. Additional walk-downs resulted in the discovery of leakage indications on the tubing of five other RCS instrument lines and on tubing in the pressurizer liquid sample line delay coil. Small accumulations of dried boron on the outside of the tubing were the only indications of leakage. The failure mechanism is transgranular stress corrosion cracking initiated from the outside diameter due to the presence of contaminants on the outside surface of the tubing.

Cook Unit #1 (LER #31598027). On May 5, 1998, inspection results identified varying amounts of construction-related debris and boric acid deposits in the Unit 1 Containment Spray header and residual heat removal (RHR) spray header and nozzles. The most probable cause for the boric acid deposits/blockage in the Unit 1 RHR spray piping is inadequate inspection of RHR system piping after a 1979 inadvertent spray actuation.

Surry Unit #1 (LER #28098006). On March 24, 1998, it was noted that there was a boric acid build-up on the head of the RCP lower radial bearing resistance temperature detector connection. A sample of the water revealed that the water was from the RCS indicating a through wall leak of the thermowell.
Palo Verde Unit #1 (LER #52899006). On October 2,1999, a small accumulation of boric acid residue was discovered on an RCS loop 2 hot leg instrument nozzle. The boric acid had accumulated on the exterior of the hot leg piping around the outer perimeter of the instrument nozzle.

Point Beach Unit #1 (LER #26699012). On November 4, 1999, a through-wall defect or flaw on the upstream weld for valve 1RC-526A, the isolation valve for the Unit 1 ~AU steam generator channel head drain. This indication was discovered while conducting an informational liquid dye penetrant examination of that weld due to the visual identification of boric acid crystals on the weld.

Waterford Unit #3 (LER #38299002). On February 25, 1999, RCS pressure boundary leakage involving two Inconel 600 instrument nozzles on the top head of the pressurizer was discovered. Subsequent inspections of the remainder of Inconel 600 nozzles identified 3 more leaking nozzles. One is on RCS Hot Leg #1 RTD nozzle, one is on RCS Hot Leg #1 sampling line, and one is on RCS Hot Leg #2 differential pressure instrument nozzle. The apparent cause of the leaks is axial cracks near the heat-affected zone of the nozzle partial penetration welds resulting from PWSCC. The leaking pressurizer nozzles have been repaired using a welded nozzle replacement. The leaking Hot Leg nozzles have been temporarily repaired using a Mechanical Nozzle Seal Assembly (MNSA).

Palisades Unit #1 (LER #25599004). On October 16, 1999, moisture and/or boric acid deposits on the exterior surfaces of three CRDM seal housings was discovered. The affected seal housings were removed when plant conditions permitted, and on November 2, 1999, two of the three were determined to have small through-wall cracks. All 45 seal housings were ultimately removed from the head and inspected utilizing visual, liquid penetrant (PT), and eddy current examination techniques The inspections revealed that 30 of the 45 seal housing assemblies contained small circumferential cracks. Three seal housing tubes also contained small axial cracks. Examination of spare housing showed similar crack indications The cracking has been determined to be transgranular stress corrosion cracking.

Arkansas Nuclear Unit #2 (LER #36800001). On July 30, 2000, twelve pressurizer heater sleeves and one RCS hot leg resistance temperature detector nozzle were found to have been leaking. Leakage was indicated by boric acid accumulation. The root cause evaluation concluded that the failure mechanism was PWSCC of Alloy 600 material.

Palo Verde Unit #2 (LER #52900004). On October 4, 2000, a small accumulation of boric acid residue was discovered on a reactor coolant system pressurizer heater sleeve (Alloy 600). Subsequent eddy current testing confirmed a liner indication in the sleeve.

Waterford Unit #3 (LER #38200011). On October 17, 2000 evidence of leakage was discovered on a pressurizer heater sleeve. The other two cases of leakage were discovered during inspections on October 19, 2000 and involved evidence of leakage at two of the three MNSA clamps that had been installed during the refuel 9 outage as temporary repairs of leaking RCS nozzles. The three leakage cases were due to 1) PWSCC, 2) a MNSA clamp flange not being flat against the pipe and 3) a MNSA clamp seating itself, respectively.

Arkansas Nuclear Unit #1 (LER #31300003). On February 15, 2000, a weld in a RCS hot leg level instrumentation nozzle was found to have been leaking as indicated by boron buildup. Cracked welds were later found on the other six hot leg level instrumentation nozzles of similar design. One weld crack was subsurface. The root cause was determined to have been using Alloy 182 weld metal exposed to RCS water in a highly restrained weld joint that had not been stress relieved, resulting in PWSCC.
Summer Unit #1 (LER #39500008). On 10/7/00, an accumulation of boric acid near the "A" loop of the RPV was discovered. Subsequent inspections revealed small amounts of boron buildup on the weld between the vessel nozzle and the hot leg pipe. A PT examination of the pipe identified a 4 inch indication at the weld approximately 3 feet from the vessel between the hot leg piping and the reactor vessel nozzle. The indication was located about 17 inches from the top of the pipe. Subsequent ultrasonic examination from the inside diameter identified an axial flaw less than 3 inches long. The same examination determined that the original indication was not the source of the leak. The PT indication were later determined to be steam cutting/boric acid corrosion at the nozzle butter to nozzle interface.

Oconee Unit #1 (LER #26900006). On November 25, 2000, small amounts of boric acid was found on the top surface of the RPV head. The deposits appeared to be located at the base of 5 (of the 8) unused thermocouple (T/C) and the #21 CRDM nozzles at points where they penetrate the RPV head surface. On December 4, 2000, an eddy current test was performed on the inside surface of the 8 T/C nozzles and revealed axial crack-like indication on the inside diameter of the nozzles in the vicinity of the partial penetration weld (on the underside of the RPV head). On December 9, 2000, a PT on CRDM #21 identified two very small pin hole indications. PWSCC was determined to be the primary failure mechanism of both the T/C nozzles, and CRDM weld cracks.

4.0 REPORTED EVENTS INVOLVING PRIMARY SYSTEM LEAKAGE OR BORIC ACID CORROSION

Plants reporting primary system leakage or boric acid corrosion are listed below in alphabetical order. The licensee event report number, if issued, is given in the parenthesis.

Arkansas Nuclear Unit #1 (31386006), 10/23/1986, Corrosion of a RCS nozzle and adjacent cold leg.

Arkansas Nuclear Unit #1 (31389043), 12/8/1989, Control rod drive mechanism nut ring halves had corroded approximately 50% and that two of the four bolt holes in the corroded nut ring half were degraded.

Arkansas Nuclear Unit #1 (31390021), 2/22/1990, RCS leak in the area of a pressurizer upper level instrumentation nozzle.

Arkansas Nuclear Unit #1 (31300003), 2/15/2000, RCS hot leg level instrumentation nozzle was found to have been leaking as indicated by boron buildup.

Arkansas Nuclear Unit #1 (31301002), 3/24/2001, Indication of boric acid crystals were noted in the area of one CRDM nozzle on the RPV.

Arkansas Nuclear Unit #2, (36887003), 4/24/1987, Pressurizer heaters had ruptured resulting in damage to the heater sleeves, causing boric acid induced corrosion damage to the pressurizer carbon steel base metal.

Arkansas Nuclear Unit #2 (36800001), 7/30/2000, Twelve pressurizer heater sleeves and one RCS hot leg resistance temperature detector nozzle were leaking
Beaver Valley Unit #2 (41200003), RCS leakage into the containment building was an abrupt packing leak on a motor-operated drain insolation valve on the RCS.

Calvert Cliffs Unit #1 (31794004), 2/21/1994, Higher than anticipated corrosion of three nuts on one of the Incore Instrumentation flanges on the Unit 1 RPV head.

Calvert Cliffs Unit #1 (31794003), 3/21/1994, Pressurizer heater sleeves leaking.

Calvert Cliffs Unit #2 (31889007), 5/5/1989, Reactor coolant leakage from 28 of the 120 pressurizer vessel heater penetrations and one upper level nozzle.

Calvert Cliffs Unit #2 (31894003), 7/11/1994, Leak caused by a 150 degree circumferential crack in a weld in the 22A Safety Injection Tank discharge test connection.

Catawba Unit #1 (41389020), Catawba Units 1 and 2 steel containment vessel exterior surfaces corroded by boric acid.

Catawba Unit #2 (41401002), 9/19/2001, Steam generator 2B lower head bowl drain indicated boron residue buildup.

Cook Unit #1 (31598027), 5/5/1998, Boric acid deposits/blockage in the Unit 1 RHR spray piping

Crystal River Unit #3 (30201004), 10/1/2001, CRDM nozzle #32 leaking from two axially oriented cracks that were through-wall.

Davis-Besse Unit #1 (34698009), 9/9/98, Boric acid leak and corrosion of three fasteners of the pressurizer spray valve.

Davis-Besse Unit #1 (34602002), 2/27/02, CRDM nozzles revealed axial indications and leakage on nozzles #1, 2, and 3, and RPV head wastage.

Diablo Canyon Unit #1 (27588004), 2/25/1988, Leaks in canopy seal welds of the CRDM head adapter plugs.

Diablo Canyon Unit #1 (27590010), 7/26/1990, leakage through a crack in the positive displacement charging pump suction piping elbow.

Diablo Canyon Unit #2 (32387023), 10/9/1987, Leaks in Unit 1 and 2 accumulator nozzles.

Ft. Calhoun Unit #1 (28590028), 12/14/1990, RCS leakage on spare CRDM housings

Ft. Calhoun Unit #1 (28592018), 3/20/1992, Severe corrosion of the carbon steel fasteners on the boric acid pump flanges and piping supports.

Haddam Neck Unit #1 (21396019), 8/31/1996, Pinhole leak in the body of an eight inch inlet isolation valve (RH-V-791A) to the 'A' RHR heat exchanger.

Maine Yankee Unit #1 (30995013), 10/16/1995, Seven of eight bonnet retention cap screws parted during attempts to remove them due to boric acid corrosion of the High Pressure Safety Injection Loop 2 Stop valve.

McGuire Unit #1 (36989020), 7/27/1989, Abnormal degradation of Unit 1 and 2 steel containment vessels because of boric acid corrosion.

Millstone Unit #2 (33695023), 5/16/1995, Indications on Boric Acid section of the Chemical and Volume Control System fittings and pipe subjected to periodic boric acid leaks over the years from valves.

Millstone Unit #2 (33602001), 2/19/2002, Two pressurizer heater sleeve penetrations were leaking as evidenced by boron precipitation build up.

Millstone Unit #3 (42389031), 11/28/1989, Pressurizer safety valve nozzle ring set screw corroded by boric acid.

Millstone Unit #3 (42394012), 9/9/1994, Leak in 3/4-inch socket weld on a 'C' RCS Loop Flow Instrumentation line cause by a circumferential crack approximately, 5/8-inch long.

Millstone Unit #3 (42395020), 12/2/1995, Leak from the valve stem leak-off pipe for the RHR System.

North Anna Unit #2 (33901003), 11/13/2001, Through-wall leak on RPV penetration number 63 was identified based on the presence of boric acid.

Oconee Unit #1 (26900006), 12/4/2000, Boric acid deposits at 8 unused thermocouple nozzles and one CRDM nozzle.

Oconee Unit #2 (27097001), 4/21/1997, Leak from a crack at the safe end to pipe weld on the High Pressure Injection to RCS cold leg nozzle near Reactor Coolant Pump.

Oconee Unit #2 (27001002), 4/28/2001, Multiple leaking CRDM nozzles

Oconee Unit #3, (28791008), 11/23/1991, Leak from a failed fitting on an instrument line at the top of a steam generator resulted in approximately 87,000 gallons of RCS leakage.

Oconee Unit #3 (28701001), 2/18/2001, Boric acid deposits were identified around nine (Nos. 3, 7, 11, 23, 28, 34, 50, 56, and 63) of 69 total CRDM nozzles

Oconee Unit #3 (28701003), 11/12/2001, Boric acid deposited at the base of seven CRDM nozzles.

Palisades Unit #1 (25593011), 10/9/1993, Pressurizer upper and lower temperature nozzle penetrations were leaking.

Palisades Unit #1 (25599004), 11/2/1999, Boric acid deposits on three CRDM seal housings and 30 of the 45 seal housing assemblies contained small circumferential cracks.

Palisades Unit #1 (25501002), 3/31/2001, 13 CRDM seal housings were not returned to service due to NDE indications, confirmed cracks, or mechanical seal performance deficiencies.

Palo Verde Unit #1 (52899006), 10/2/1999, Boric acid residue on a reactor coolant system loop 2 hot leg instrument nozzle.

Palo Verde Unit #1 (52801001), 3/31/2001, Boric acid on an RCS hot let instrument nozzle.

Palo Verde Unit #2 (52900004), 10/4/2000, Boric acid residue on a RCS pressurizer heater sleeve.

Point Beach Unit #1 (26690008), 7/20/1990, Reactor coolant was leaking through a canopy seal weld on CRDM I-3 and the upstream weld on B steam generator channel head drain line isolation valve 1RC-526B.

Point Beach Unit #1 (26699012), 11/4/1999, Through-wall leak in valve 1RC-526A, boric acid crystals on the weld.

Salem Unit #2 (No LER), 8/7/1987, A pile of rust-colored boric acid crystals 3 feet by 5 feet by 1

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foot high had accumulated on the head, and a thin white film of boric acid crystals had coated several areas of the head and extended 1 to 2 feet up the CRDM housings.

Salem Unit #2 (31198007), 7/30/1998, Leakage indications on the tubing of six RCS instrument lines and on tubing in the pressurizer liquid sample line delay coil.

San Onofre Unit #2 (36192004), 2/18/1992, Rust and boric acid crystals in the vicinity of the pressurizer vapor space level instrument nozzle.

San Onofre Unit #2 (36198002), 1/26/1998, Leakage from cracks through instrument nozzles.

San Onofre Unit #3 (36295001), 7/22/1995, Leakage from pressurizer a level instrumentation nozzle and two RCS hot leg instrument nozzles.

San Onofre Unit #3 (36297001), 4/12/1997, Leaking instrument nozzles in RCS.

San Onofre Unit #3 (36297002), 7/3/1997, Leaking RCS nozzles.

Seabrook Unit #1 (44392026), 7/14/1992, Cover bolts had fractured on multiple valves.

St. Lucie Unit #1 (33587014), 10/8/1987, Leaking check valve bonnet and a cracked pipe in the heat affected zone on the 1A1 reactor coolant pump (RCP) lower cavity seal nozzle.

St. Lucie Unit #1 (33501003), 4/14/2001, Through wall RCS leak on a hot leg instrument nozzle.

St. Lucie Unit #2 (38994002), 3/16/1994, Boric acid on the exterior of the pressurizer steam space instrument nozzles.

St. Lucie Unit #2 (38995004), 10/10/1995, Instrument nozzle located on the 'B' side RCS hot leg exhibited an apparent boric acid buildup

Summer Unit #1 (39500008), 10/12/2000, Boron buildup on the weld between the reactor vessel nozzle and the hot leg pipe.

Surry Unit #1 (28098006), 3/24/1998, Boric acid build-up on the head of the RCP lower radial bearing resistance temperature detector connection

Surry Unit #1 (28095007), 9/12/1995, Boron crystals and corrosion products were discovered on the outside diameter of the reactor vessel for two of the four instrument nozzles.

Surry Unit #2 (28192008), 12/15/1992, RCS leak had developed near the Low Pressure Letdown Flow Transmitter.

Three Mile Island Unit #1 (28994001), 3/7/1994, Body-to-bonnet leak from pressurizer spray valve (RC-V1) caused by boric acid degradation of its fasteners.

Three Mile Island Unit #1 (28901002), 10/12/2001, boric acid buildup around all eight thermocouple nozzles and boric acid buildup around 12 CRDM nozzles.

Turkey Point #4 (No LER), 3/13/87, Boric acid on the RPV head results in severe corrosion of various components.

Waterford Unit #3 (38292002), 3/25/1992, Packing gland studs on reactor coolant hot leg sample valve failed due to boric acid corrosion.

Waterford Unit #3 (38292006), 7/11/1992, Packing gland studs on reactor coolant hot leg sample valve failed due to boric acid.

Waterford Unit #3 (38299002), 2/25/1999, Leakage on pressurizer instrument nozzles and hot leg nozzles.

Waterford Unit #3 (38200011), 10/17/2000, Leakage at a pressurizer heater sleeve and two cases of leakage on two MNSA clamps

APPENDIX F

SUMMARY OF RECURRING ISSUES RELATED TO PREVIOUS NRC LESSONS-LEARNED EFFORTS

The task group reviewed the reports from previous NRC lesson-learned activities to determine if there were issues common to those resulting from the Davis-Besse lessons-learned review. The reports reviewed were:

- "Indian Point 2 Steam Generator Tube Failure Lessons-Learned Report," October 23, 2000
- Report of the Millstone Lessons Learned Task Group, Part 1: Review and Findings," September 13, 1996.
- SECY 97-036, "Millstone Lessons Learned Report, Part 2: Policy Issues"
- "Task Force Report Concerning the Effectiveness of Implementation of the NRC's Inspection Program and Adequacy of the Licensee's Employee Concerns Program at the South Texas Project," March 31, 1995

The staff found several areas where previous assessments had uncovered performance or programmatic weaknesses similar to those uncovered in the Davis Besse review.

The table on the following page summaries the assessment of recurring NRC lessons:

[Note: The lessons and recommendations from the South Texas effort are listed in Section 5 of its report. The recommendations for India Point 2 are listed in a table in Section 9 of its report. The recommendations for the Millstone effort are in a table provided in the appendix of the Part 2 report. As applicable, recommendation numbers from the source documents are provided in the table here for ease of reference.]

Issue From Davis Besse	Commonality to Previous Lessons or Recommendations	NRC Follow up
Closeout of inspection findings before licensee implementation of corrective actions	Millstone (items 4, 6)	
Program guidance for assessing long-standing hardware problems	South Texas Indian Point-2 (item 5e)	
NRC Inspector/reviewer skills, abilities, experience	Indian Point-2 (items 5b, 5c) Millstone (item 14) South Texas	
Process to verify information	Millstone (item 2) Indian Point-2 (item 6d)	
NRC review of routine reports	Indian Point-2 (item 6c)	
NRR/regional Office interaction during safety evaluation development	Indian Point-2 (item 6d)	
Specific review guidance	Indian Point-2 (item 6a)	
Integration of Inspection findings	South Texas	
Performance review process	Indian Point-2 (items 5a, 5e, 5f) Millstone (items 3, 13, 15) South Texas	
Inadequate Industry Guidance	Indian Point 2 (item 2)	
Inadequate requirements in licensing basis	Indian Point 2 (item 3)	

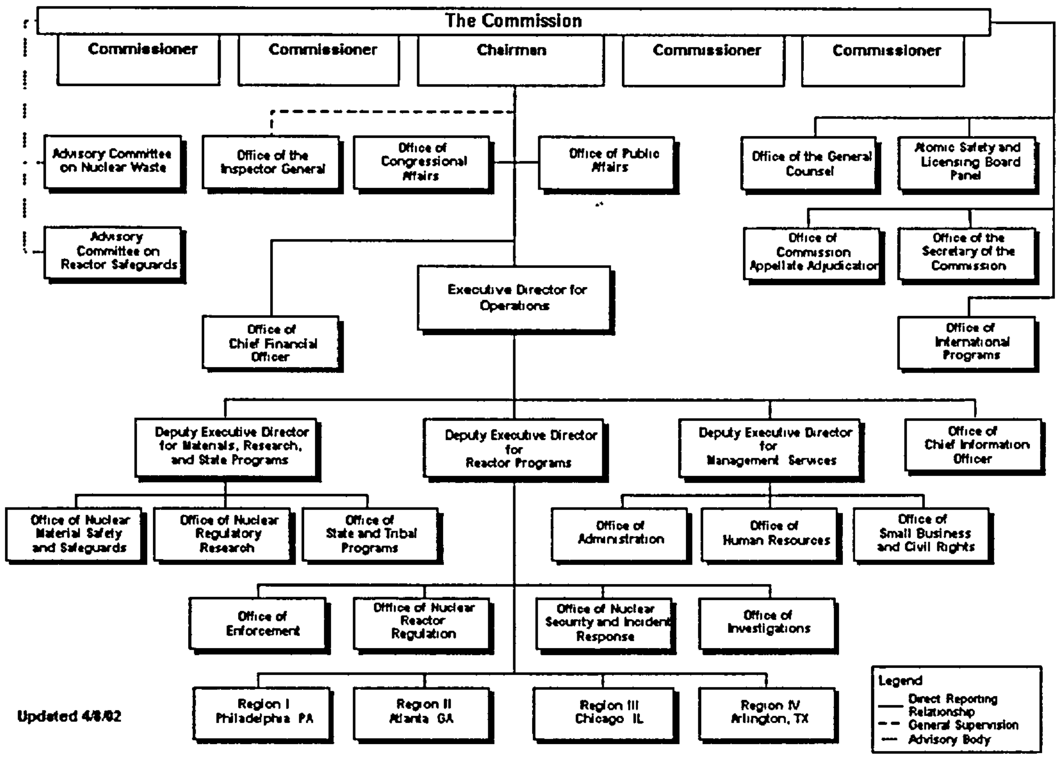
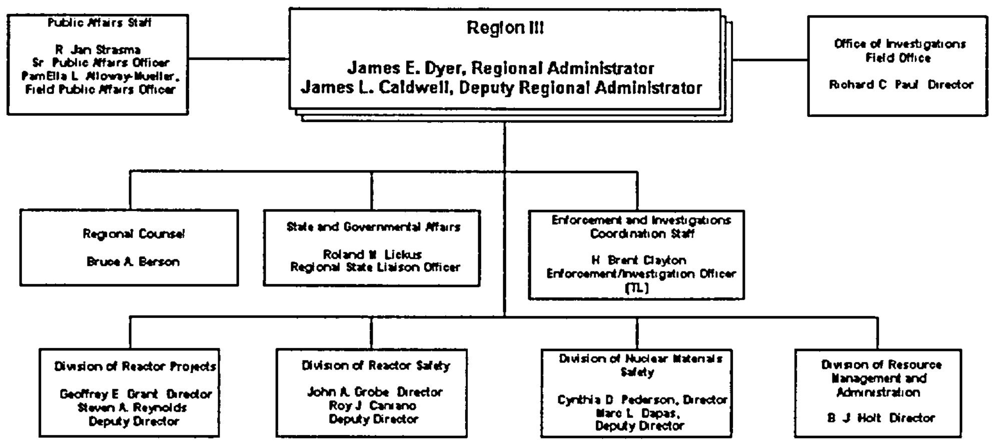
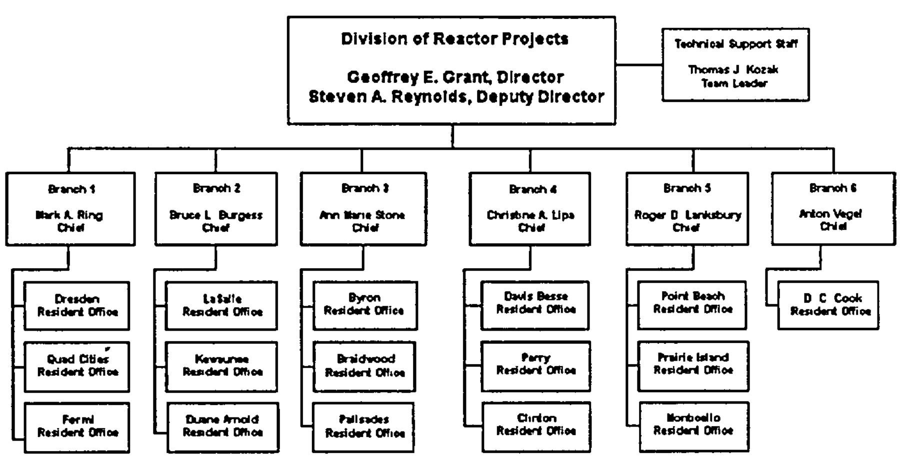


Figure 1-1 NRC Organization


Public Affairs Staff
R Jan Strasma
Sr Public Affairs Officer
PamElla L Alloway-Mueller,
Field Public Affairs Officer
Region III
James E. Dyer, Regional Administrator
James L. Caldwell, Deputy Regional Administrator
Office of Investigations
Field Office
Richard C Paul Director
Regional Counsel
Bruce A. Berson
State and Governmental Affairs
Roland M Lickus
Regional State Liaison Officer
Enforcement and Investigations
Coordination Staff
H Brent Clayton
Enforcement/Investigation Officer
(TL)
Division of Reactor Projects
Geoffrey E Grant Director
Steven A. Reynolds
Deputy Director
Division of Reactor Safety
John A. Grobe Director
Roy J Caniano
Deputy Director
Division of Nuclear Materials
Safety
Cynthia D Pederson, Director
Marc L Dapas,
Deputy Director
Division of Resource
Management and
Administration
B J Holt Director


Division of Reactor Projects
Geoffrey E. Grant, Director
Steven A. Reynolds, Deputy Director
Technical Support Staff
Thomas J Kozak
Team Leader
Branch 1
Mark A. Ring
Chief
Branch 2
Bruce L Burgess
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Branch 3
Ann Marie Stone
Chief
Branch 4
Christine A. Lipa
Chief
Branch 5
Roger D Lanksbury
Chief
Branch 6
Anton Vegel
Chief
Dresden
Resident Office
Quad Cities
Resident Office
Fermi
Resident Office
LaSalle
Resident Office
Kewaunee
Resident Office
Duane Arnold
Resident Office
Byron
Resident Office
Braidwood
Resident Office
Palisades
Resident Office
Davis Besse
Resident Office
Perry
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Clinton
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Point Beach
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Prairie Island
Resident Office
Monticello
Resident Office
D C Cook
Resident Office

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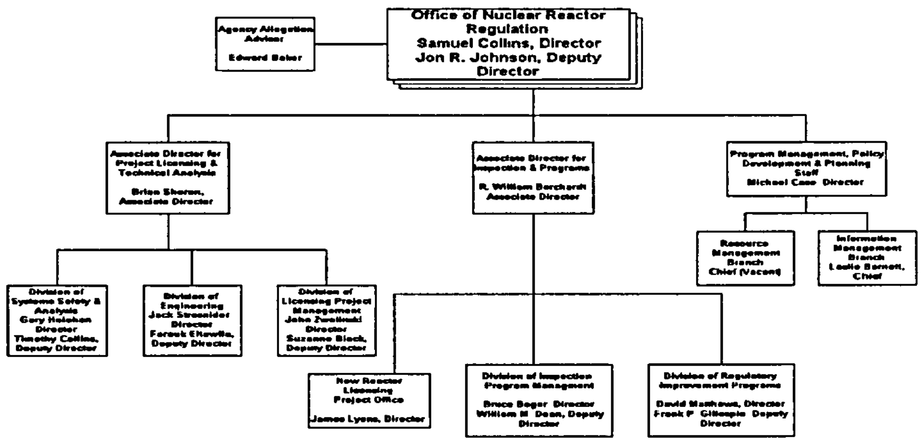
Office of Nuclear Reactor Regulation
Samuel Collins, Director
Jon R. Johnson, Deputy Director
Agency Allegation Advisor
Edward Baker
Associate Director for Project Licensing & Technical Analysis
Brian Sheron, Associate Director
Associate Director for Inspection & Programs
R. William Borchardt Associate Director
Program Management, Policy Development & Planning Staff
Michael Case Director
Resource Management Branch
Chief (Vacant)
Information Management Branch
Leslie Barnett, Chief
Division of Systems Safety & Analysis
Gary Holahan Director
Timothy Collins, Deputy Director
Division of Engineering
Jack Strosnider Director
Farouk Eltawila, Deputy Director
Division of Licensing Project Management
John Zwolinski Director
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DAVIS-BESSE SITE ORGANIZATION

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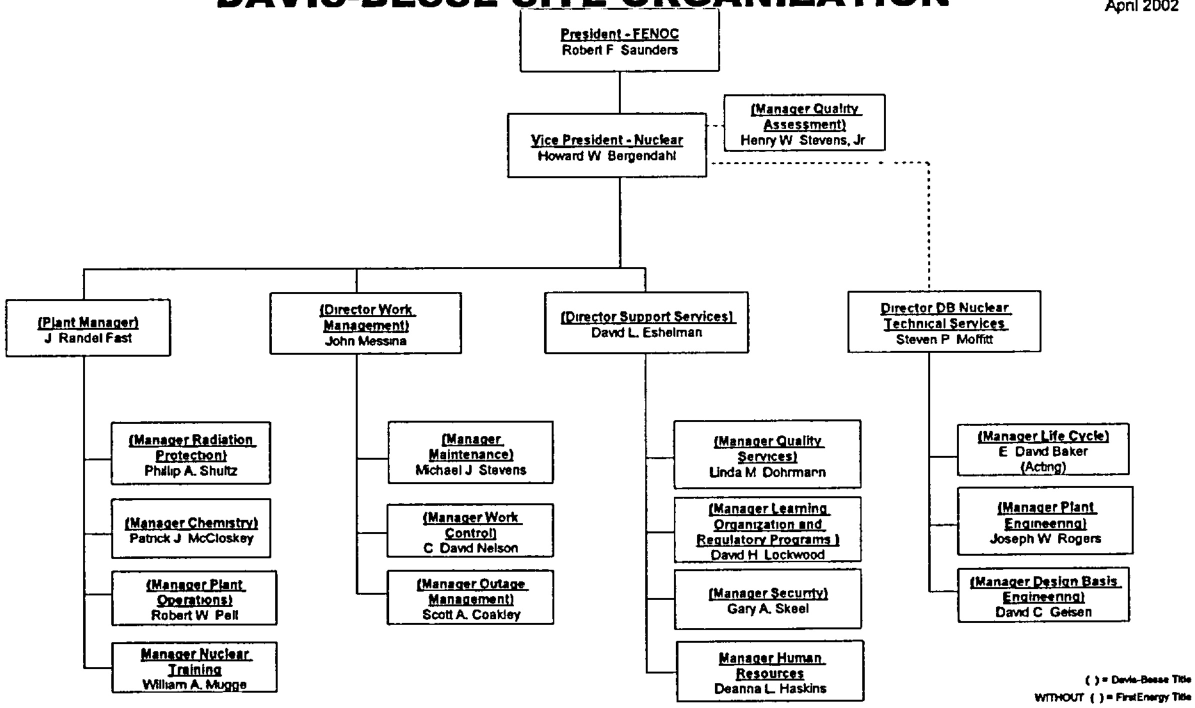

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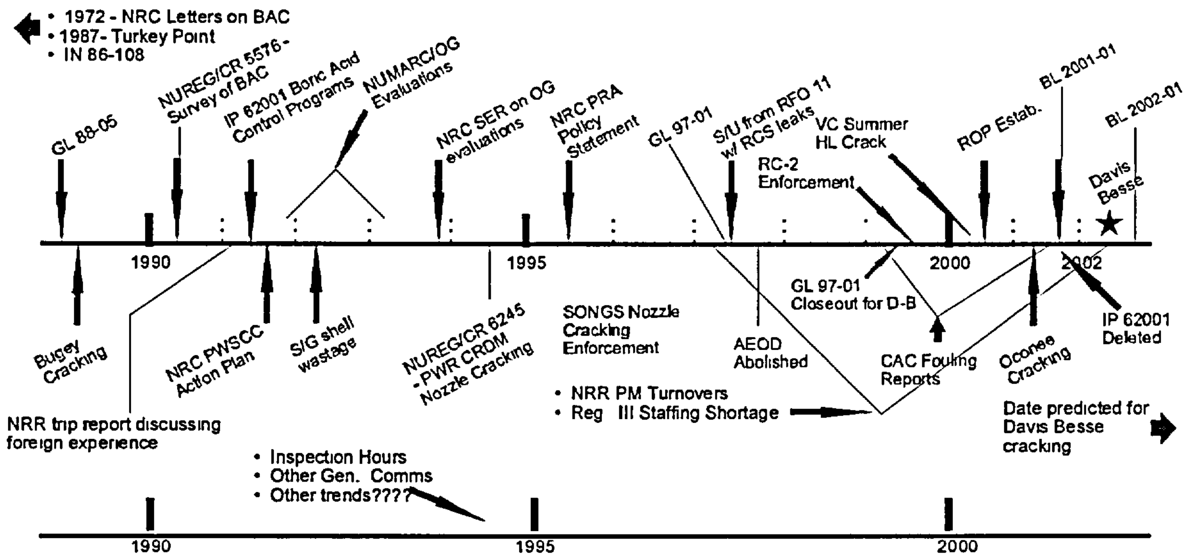
NRC PREDECISIONAL

Figure 3.1-1



NRC and Industry Failed To Assess Operating Experience

NRC PREDECISIONAL

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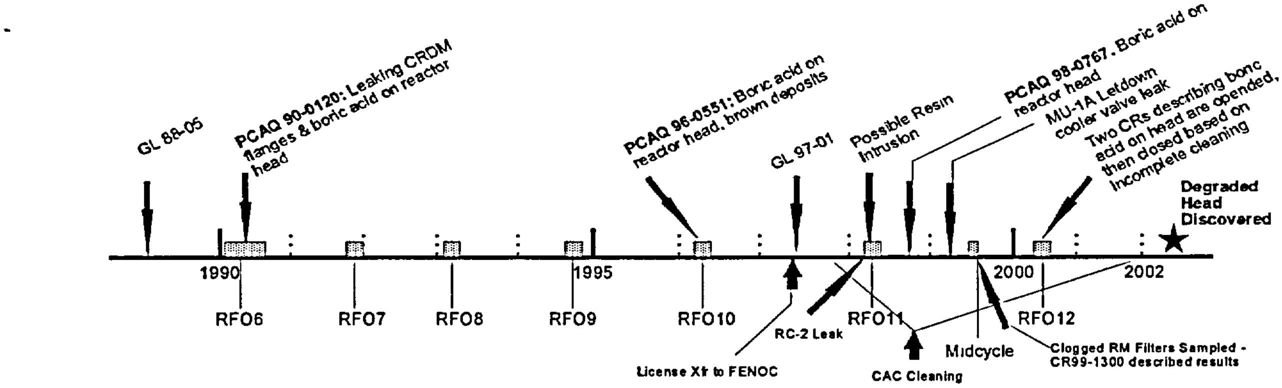
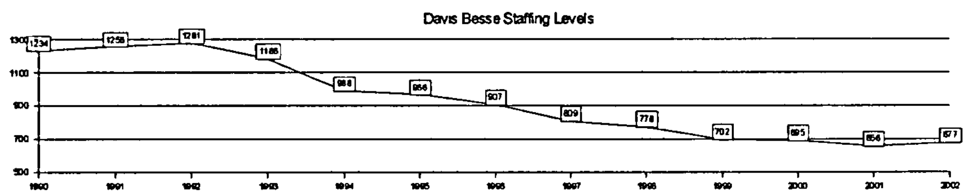
NRC PREDECISIONAL

Figure 3.2-1





Licensee Failed to Identify Boric Acid Deposits and Correct

NRC PREDECISIONAL

NRC PREDECISIONAL

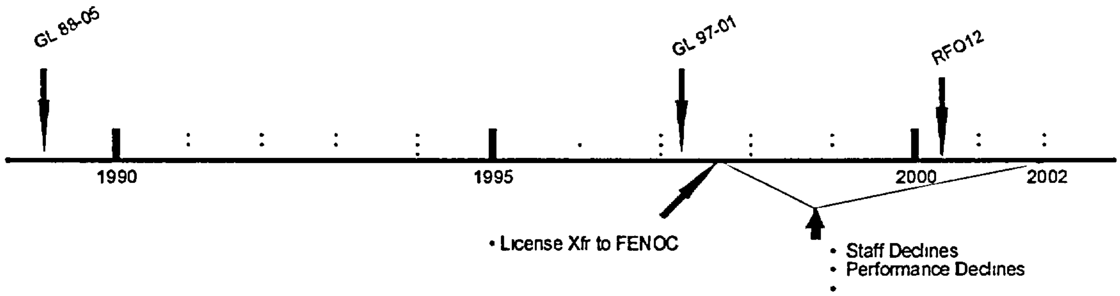


Figure 3.3-1
NRC Failed To Assess Safety Performance at Davis Besse

NRC PREDECISIONAL

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1. INTRODUCTION

1.1 Objective

The NRC has conducted a number of lessons-learned reviews to assess regulatory processes relative to significant plant events or safety performance issues Consistent with this practice, the NRC's Executive Director for Operations (EDO) directed the formation of an NRC task force in response to the issues associated with the extensive degradation to the pressure boundary material of the Davis-Besse Nuclear Power Station (DBNPS) reactor pressure vessel (RPV) head. The objective of the Davis-Besse Reactor Vessel Head Degradation Lessons-Learned Task Force (task force) is defined in a publicly available NRC memorandum, dated May 15, 2002, from William D. Travers, EDO, to Arthur T. Howell III, the task force team leader.

This memorandum and attachment describe the approach and charter for the inter-office task force to assess the lessons-learned related to the degradation of the DBNPS RPV head that was identified by representatives of FirstEnergy Nuclear Operating Company (FENOC), the licensee for DBNPS, on March 5, 2002. The objective of this effort was to conduct an independent evaluation of the NRC's regulatory processes related to assuring reactor vessel head integrity in order to identify and recommend areas for improvement applicable to the NRC and the nuclear industry.

1.2 Scope

The task force conducted review activities of the following five areas: 1) reactor oversight process issues; 2) regulatory process issues; 3) research activities; 4) international practices; and 5) the NRC's Generic Issue process In reviewing these five areas, the task force conducted fact finding at DBNPS to determine what pertinent plant information was available to be reviewed by NRC. Also, the task force conducted review activities in the NRC headquarters and regional offices The following specific areas were reviewed

- NRC Inspection (Operations Phase) Program and Implementation
- NRC Operating Reactor Assessment Program and Implementation
- NRC Enforcement Guidance and DBNPS Enforcement History
- Allegation History of FENOC Nuclear Plants
- Applicable NRC Regulatory Requirements
- NRC Licensing Review Processes and Implementation
- NRC Operating Experience Review Process and Implementation
- Research Activities
- NRC Generic Communication Process and Implementation
- NRC Generic Issue Program and Implementation
- International Experience and Practices
- Industry Guidance for Managing Regulatory Commitments
- Applicable Industry Technical Guidance and Initiatives

The task force did not conduct a detailed technical review of the DBNPS Alloy 600 reactor pressure vessel head penetration (VHP) nozzle cracking wastage mechanisms since these areas are the focus of other NRC review activities. The task force reviewed the results of the

NRC's Augmented Inspection Team (AIT), including the preliminary results of the AIT follow up inspections and considered the available information associated with the licensee's various root cause determination efforts.

Since the task force was primarily concerned with why the DBNPS RPV head degradation event was not prevented, it did not focus on the NRC's actions subsequent to the time of discovery of the problem. Nevertheless, during its review, the task force identified a number of issues associated with the NRC's response to the event which are documented in the report

The task force coordinated its review activities with other related on-going reviews being conducted by the NRC's Oversight Panel that was formed in accordance with NRC Inspection Manual Chapter 0350, "Oversight of Operating Reactor Facilities in an Extended Shutdown as a Result of Significant Performance Problems " Also, the task force coordinated its activities with other NRC review activities.

The task force conducted a public meeting near the DBNPS site on June 12, 2002 and conducted another public meeting in the NRC Headquarters Offices on June 19, 2002 to solicit public comments on the scope of the task force review activities. The following is a summary of the comments received by those who participated in the meetings:

- There is a nexus between the RPV head degradation event and the significant decrease in DBNPS staffing levels that has occurred over the past years;
- There are some DBNPS corrective actions stemming from the 1985 loss of auxiliary feedwater event that should have precluded the RPV head degradation event;
- The task force completion schedule may not be adequate to support a thorough review;
- The DBNPS RPV head degradation event could be attributed mainly to plant implementation issues;
- A review of the DBNPS Updated Final Safety Analysis Report did not reveal any discussion of the analyses of safety issues performed in response to NRC requests associated with four specific NRC generic communications, which appears to represent noncompliance with 10 CFR 50.71(e);
- A question was raised regarding the validity of risk assessments which consider incremental risk associated with short durations (i.e., the period between December 31, 2001 and February 16, 2002), and;
- A question was raised regarding the relevance of calculations demonstrating the unlikelihood of the RPV head stainless steel cladding from catastrophically failing under both normal and transient pressure loading relative to the NRC significance determination of the DBNPS RPV head degradation.

The task force considered all of these comments. Several of them were specifically included in the detailed review plans discussed in Section 1.3.

The charter was revised three times during the course of the task force's review activities. These revisions were made to address the addition of observers from the State of Ohio, changes to the task force team composition, and a change to the task force review schedule.

1.3 Preparation, Review and Assessment Methodologies

The task force effort consisted of a preparation phase, a review phase, and an assessment and documentation phase. Discrete scheduler milestones were established for each of these phases. Additionally, the task force was organized into two distinct groups. One group focused principally on DBNPS fact finding, as well as, the applicable regulatory programs, processes, and implementing procedures involving inspection, enforcement, industry operating experience, generic communications, allegations, and plant safety performance assessment. A second group focused principally on the scope of the applicable requirements, licensing review processes, the industry process for managing regulatory commitments, applicable industry technical guidance and initiatives, international experience and practices, research activities, and the NRC's Generic Issue process

During the preparatory phase, a number of activities were conducted to facilitate the review and assessment phases. The task group discussed the scope, objective and specifics of the charter with NRC managers and staff members to establish potential lines inquiry to be considered during the review. Coordination briefings were conducted with other NRC offices, as well as representatives from the State of Ohio and a representative of Ottawa County, Ohio. The NRC's Office of Enforcement provided a summary of the DBNPS enforcement history, as well as an analysis of enforcement actions involving Alloy 600 nozzle cracking, reactor coolant pressure boundary (RCPB) leakage, and boric acid corrosion of carbon steel components. A summary of allegations for DBNPS and other FENOC nuclear plants was reviewed The Oak Ridge National Laboratory compiled a summary of NRC reportable events involving boric acid leakage and corrosion. Orientation briefings and training were provided to the task force members. Licensee, NRC, and industry documents and records were obtained and reviewed in order to develop detailed review plans. These plans identified specific items to be considered for review, including pre-identified issues and individuals to be interviewed. The NRC and the State of Ohio established an informal agreement which governed the observation of the task force's activities by representatives of the state. As discussed in Section 1.2, two public meetings were conducted to obtain public comments on the task force charter.

During the review phase, the task force conducted independent fact finding at the DBNPS site, and conducted review activities involving all four regional offices and the headquarters offices. These review activities principally involved interviews of personnel and reviews of records. Figures 1-1 and 1-2 depict the DBNPS and NRC organizational structure, respectively.

While at the DBNPS site, members of the task force reviewed licensee records, interviewed approximately 45 licensee managers and staff members, and toured the containment building and other selected areas of the facility. A representative of the State of Ohio observed the task force's review activities at DBNPS

The DBNPS fact finding focused on a review of the reactor vessel head degradation condition and related issues, such as: 1) reactor coolant system (RCS) leakage history; 2) the symptoms associated with active RCS leaks; 3) the boric acid corrosion control program; 4) precursor events, with emphasis on a 1993 issue involving the boric acid corrosion wastage of the head vent flange on Steam Generator No. 2 and a 1998 issue involving the boric acid corrosion wastage of inadvertently installed carbon steel pressurizer spray valve nuts; 5) the licensee's documented submissions and actions in response to key NRC generic communications, such as Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," and Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles."

As part of the on-site fact finding at DBNPS, the task force reviewed licensee policies, programs, processes, and activities associated with items 1 through 5 noted above. This included the following: oversight activities, including quality assurance audits, performance indicators, line self-assessments, third-party assessments, offsite nuclear review board assessments, action and improvement plans, and root cause analyses associated with this event; staffing and budgeting; outage scoping and scheduling; corrective actions; employee concerns (Ombudsman); training; regulatory commitment management, internal and external industry operating experience; plant operations; maintenance and testing; plant (system) and design engineering; radiological protection; licensing and compliance; and licensee involvement in the Babcock & Wilcox Owners Group (B&WOG). Appendix C documents the index of licensee records requested and reviewed by the task force.

The fact finding conducted by the task force at NRC headquarters consisted of reviewing several NRC programs and functional areas to determine if deficiencies in these areas contributed to the development of the event at DBNPS. The task force reviewed DBNPS licensing documents, NRC policy and procedural documentation, industry generic technical reports, applicable industry codes, and NRC generic reports associated with boric acid corrosion, VHP nozzle degradation, and reactor coolant system (RCS) leakage integrity. The headquarters review also focused on generic information related to VHP nozzle cracking and boric acid corrosion, and the regulatory history associated with these issues. The task force explored areas connected to the event that are not considered contributors, such as: the process followed by NRC in deciding to allow operation of DBNPS past December 31, 2001; and the use of risk information by the NRC in determining the significance of the event. Appendix C lists the NRC and industry documents used by the task force in preparing this report.

The task force conducted a limited review of past NRC lessons-learned review reports to determine whether there were any recurring problems. These included: 1) Indian Point 2 Steam Generator Tube Failure Lessons-Learned Report; 2) Task Force Report Concerning the Effectiveness of Implementation of the NRC's Inspection Program and Adequacy of the Licensee's Employee Concerns Program at the South Texas Project; and 3) Millstone Lessons Learned Task Group Report, Part 1: Review and Findings, and Part 2: Policy Issues. The results of this review are documented in Appendix F.

The task force interviewed approximately 80 NRC employees from all four NRC regional offices and the NRC's headquarters offices. Additionally, the task force conducted limited review activities involving other B&W plants in three other NRC regions, as well as two other plants in NRC Region III. For each of these plants, the task force reviewed: licensee actions in response to GLs 88-05 and 97-01; or NRC employee site visits; or both.

The task force interviewed approximately 10 other individuals, either in person or telephonically, from several external organizations. These organizations included the Nuclear Energy Institute (NEI), Framatome Technologies, Inc. (FTI), the Electric Power Research Institute (EPRI), and IPSN (the French nuclear regulatory authority) of France.

The assessment phase consisted of a series of team meetings and independent in-office review activities. The task force used assessment techniques that were similar to those used during past NRC Incident Investigation Team and Diagnostic Evaluation Team reviews.

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2. EVENT SUMMARY AND BACKGROUND

2.1 Event Summary

On March 5, 2002, the FENOC staff, the licensee for DBNPS in Oak Harbor, Ohio, discovered a degradation cavity in the RPV head, adjacent to VHP Nozzle 3, as shown in Figures 2.1and 2.2. The DBNPS Nuclear Steam Supply System (NSSS) was fabricated by the Babcock & Wilcox (B&W) Company. Details of the typical B&W RPV head design and fabrication details are shown in Figures 2.3 and 2.4. This discovery came as the plant was shutdown for a refueling outage during which the licensee was conducting inspections for VHP nozzle cracking caused by primary water stress corrosion cracking (PWSCC). These inspections were being conducted in reaction to NRC Bulletin 2001-01. During these inspections, cracks were discovered in several VHP nozzles, including VHP Nozzle 3. The licensee had contracted with the Framatome ANP, Inc., to perform repairs of cracked VHP nozzles, where necessary, by machining away the affected portion of the VHP nozzle and re-establishing the pressure boundary by welding the VHP nozzle further up into the RPV head. Such repair practices had been successfully implemented previously at the Oconee Nuclear Station (ONS) following approval by the NRC.

Subsequent to the machining process to repair 3 VHP Nozzle 3, the penetration was observed to displace, or tip in the downhill direction as the machining apparatus was withdrawn. Under normal circumstances, such movement of the VHP nozzle would not have been possible since the VHP nozzle is laterally restrained by over six inches of RPV head material. The displacement led FENOC to examine the region adjacent to VHP Nozzle 3 and a cavity of approximately 20-30 in^2 was discovered. Upon further examination, the cavity was found to extend completely through the 6.63 inch thickness of the carbon steel RPV head down to a thin internal liner of stainless steel cladding (Figure 2.5). Hence, immediately prior to the plant shutdown for refueling, the stainless steel cladding was acting as the primary system pressure boundary over the region of the cavity. In this case, the cladding contained the primary system pressure over the cavity region during operation. However, the cladding is not designed to perform this function. Degradation of a nuclear plant primary system pressure boundary to this extent had not been observed previously either in the U.S. or abroad.

The exact mechanism(s) for the cavity degradation have not been established. However, boric acid corrosion of the carbon steel is clearly the primary contributor to the degradation. The primary corrosive attack was likely caused by leakage from a long through-wall axial crack in VHP Nozzle 3, but was also likely assisted by control rod drive mechanism (CRDM) flange leakage onto the head from above.

2.2 Background

The DBNPS contains a 2-loop pressurized water reactor (PWR). There is a primary RCS loop with two steam generators which transfer heat from the RCS to the secondary water. This heat causes the secondary water to boil, and the resulting steam is used to turn a turbine, which turns an electrical generator to produce electricity. The DBNPS RCS fabricator was the former B&W Company. The B&W Company was subsequently acquired by FTI.

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PWRs utilize water as a primary coolant and as a "moderator" to control the nuclear reaction in the reactor vessel. In addition, such light water reactors employ "control" rods to enable further control of the nuclear reaction. In a PWR, these control rods enter the reactor vessel from atop the RPV head (Figure 2.4). The RPV head is fabricated from carbon steel and is attached to the reactor vessel through a bolted and flanged connection (Figure 2.4). The interior of the RPV head is lined with stainless steel cladding as a barrier to general corrosion. The cladding is deposited through a welding process. For the typical B&W design, there are approximately 69 VHP nozzles for control rods.

The VHP nozzles are part of the RCPB which is one of three principal barriers to the release of radioactive fission products. The VHP nozzles of commercial U.S. PWRs are fabricated from Inconel 600 (also known as Alloy 600) and are approximately 4 inches in diameter and approximately 0.62 in wall thickness Inconel 600 is an alloy containing primarily nickel, but also contains iron and chromium. The alloy and associated weld materials (alloys 82 and 182) are highly resistant to general corrosion, but can be susceptible to PWSCC. The VHP nozzles are shrunk-fit and welded into pre-machined holes in the RPV head. The VHP nozzles are joined to the reactor vessel head by J-groove welds that only partially penetrate through the head thickness (see Figure 2.5). PWSCC of a VHP nozzle or the weld connecting the nozzle to the vessel head can lead to leakage from the pressure boundary. If undetected and uncorrected, this type of degradation could potentially propagate to failure of the nozzle and result in a small-break loss-of-coolant accident (LOCA). While this is not a desirable consequence, all commercial nuclear power plants are designed to accommodate certain postulated failures, including a VHP nozzle failure.

At DBNPS, a service structure is attached to the RPV head It is approximately 18 feet high and 10 feet in diameter. This structure stabilizes and houses the CRDMs and contains a horizontal layer of metallic reflective insulation approximately 2 inches above the dome center of the RPV head. The VHP nozzles welded to the vessel head pass through the insulation layer and attach to the CRDM housings with bolted flanges. These flanges are located about 9 inches above the horizontal insulation layer.

2.2.1 History of VHP Nozzle Cracking

Cracking of Alloy 600 nozzles has been occurring since the late 1980's. This operating experience pertains to domestic and foreign PWRs. Much of this experience is addressed by NRC generic communications (and industry equivalents).

The cracking of VHP nozzles was first observed at the French PWR, Bugey 3, in 1991. This cracking involved axial through-wall cracking of an Alloy 600 VHP nozzle due to PWSCC which led to leakage observed in a hydrotest. Since that time, it was known that Alloy 600 VHP nozzles were susceptible to stress corrosion cracking that could lead to through-wall leakage.

As a result of the French experience, in 1991 the NRC implemented an action plan to address PWSCC of U.S. VHP nozzles fabricated from Alloy 600. This action plan included an NRC staff review of safety assessments conducted by the PWR owners groups (i e., Westinghouse Owners Group, Combustion Engineering Owners Group and Babcock & Wilcox Owners Group). These reports addressed VHP nozzle cracking and the potential for consequent boric acid degradation of RPV heads from leakage through the VHP nozzle cracks. The U.S. industry reports concluded that axial cracking, even if through-wall, was not highly safety significant. These reports also concluded that circumferential cracking of VHP nozzles was improbable and boric acid attack of the RPV head, if it were to occur, would be discovered through boric acid inspections well before safety margins would be compromised. In a safety evaluation dated November 19, 1993, NRC largely agreed with this assessment, but decided to reserve judgment regarding circumferential cracking on a case-by-case basis, and encouraged the industry to develop enhanced VHP nozzle leakage monitoring techniques

The U.S. industry conducted pilot inspections of VHP nozzles at three U S. Nuclear plants (Oconee-2, D.C. Cook-2 and Point Beach-1) in 1994. One penetration at Oconee-2 was identified with numerous very shallow indications and one penetration at D.C. Cook-2 showed three confirmed axial cracks considerably smaller than acceptable limits (75% through-wall). No indications were identified at Point Beach.

On March 5, 1996 the Nuclear Energy Institute (NEI) submitted a report to the NRC summarizing the significance of PWSCC in VHP nozzles worldwide and describing industry activities to manage the issue. This report concluded that: (1) VHP nozzle cracking by PWSCC was not an immediate safety concern; (2) internally initiated cracking in VHP nozzles would be axial; (3) external circumferential cracking and penetration failure would be a highly improbable event; (4) corrosion of the carbon steel head in the presence of a VHP nozzle leak was possible but would take over six years before American Society of Mechanical Engineers (ASME) Code safety margins would be adversely impacted; and (5) visual inspections of RPV heads in accordance with GL 88-05 would be sufficient to detect PWSCC leakage prior to significant cracking and head corrosion. The industry concluded that the issue was primarily an economic issue rather than a safety issue.

As previously discussed, NRC agreed with the assertion that the cracking was not an immediate safety concern, but decided to reserve judgment regarding circumferential cracking on a case-by-case basis, and encouraged the industry to develop enhanced VHP leakage monitoring techniques. The NRC staff did not agree with NEI that the issue was primarily economic in nature.

In 1997, continued NRC concern with this issue led to issuance of GL 97-01 which requested licensees to inform PWR licensees of their plans relative to monitoring and managing cracking in VHP nozzles and their intentions, if any, to perform non-visual, volumetric examinations of their VHP nozzles. In July 1997, the Westinghouse Owners Group, Combustion Engineering Owners Group and Babcock & Wilcox Owners Group submitted their generic responses to GL 97-01 on behalf of their member utilities. The generic responses ranked the potential for the VHP nozzles of their member plants to develop PWSCC. Later, in 1998, NEI revised the rankings and developed an integrated program for inspecting the VHP nozzles of U.S. PWRs. NEI subsequently forwarded this program to the NRC for review in December, 1998. In regard to implementation of this program, NEI stated that licensees of U.S. PWRs should continue to perform required visual examinations of their vessel heads for leakage, and highly recommended that plants having the most susceptible VHP nozzles implement voluntary eddy current examinations of their nozzles. NEI also stated that this program would be modified, as necessary, based on the results of all examinations performed on U.S. VHP nozzles and any other pertinent information that could provide a basis for modifying the program. The NRC staff found this approach acceptable.

Generic Letter 97-01 also discussed a 1994 discovery of circumferential intergranular attack

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(IGA) associated with the weld between the inner surface of the RPV head and the CRDM penetration in one of the CRDM penetrations at Zorita, a Spanish PWR, which was believed to have been caused by ion exchange resin bead intrusions. Therefore, GL 97-01 requested information regarding the occurrence of resin bead intrusions in PWRs.

Inspections in reaction to GL-97-01 subsequently led to the discovery of extensive circumferential cracking of several VHP nozzles at ONS, Unit 3 in the spring of 2001. Prior to the discovery at ONS, Unit 3, circumferential cracking in VHP nozzles, particularly to the extent observed at ONS, Unit 3 had been considered to be improbable. Circumferential cracking in VHP nozzles is more safety significant than axial cracking since it creates the potential for separation of the penetration if the cracking is severe enough. In reaction to the ONS, Unit 3 cracking, NRC issued Bulletin 2001-01 which requested licensees to address the potential for similar cracking at their plants and discuss their plans for VHP nozzle inspections. A key aspect of addressing the potential for cracking was the effectiveness of visual examinations for leakage on the RPV heads. The Electric Power Research Institute/Materials Reliability Project (EPRI/MRP) took the lead for the industry in "binning" plants by susceptibility relative to ONS. The binning was accomplished through consideration of operating time and operating temperature. The B&W units (such as ONS and DBNPS) operate with the highest RPV head temperatures and were all considered to be highly susceptible to the potential for circumferential cracking. By November 2001, all but one of the other B&W units had identified circumferential cracking of VHP nozzles, while the remaining unit had identified axial cracking of a VHP nozzle.

Primarily on the basis of the inspection experience of the other B&W units, the NRC staff expectation in Fall, 2001 was that there would be a high likelihood of finding PWSCC cracking in VHP nozzles at DBNPs. This expectation, coupled with associated risks of potential circumferential cracking, led the staff to conclude that DBNPS should shut down to inspect the VHP nozzles by December 31, 2001. The staff initiated action to draft an order to require DBNPS to shut down. FENOC interacted extensively with the NRC during this time frame to convince the staff that it was safe to operate the plant until the next scheduled refueling outage in April 2002. Ultimately, the order was not issued and FENOC committed to reduce the DBNPS head temperature, perform volumetric examinations of 100% of the VHP nozzles and voluntarily shut down in February 2002. During subsequent inspections, VHP nozzle cracking was discovered, including through-wall cracking of several penetrations, but most notably, a long axial crack in VHP Nozzle 3. This crack was the source of the leakage that was likely the most significant contributor to the RPV head degradation.

2.2.2 History of Boric Acid Degradation

Borated water is used in PWRs as a reactivity control agent to aid in control of the nuclear reaction. If leakage occurs from the RCS, the escaping coolant flashes to steam and leaves behind a concentration of impurities, including boric acid. Under the appropriate thermodynamic conditions, boric acid can cause extensive and rapid degradation of carbon steel components. Such events, involving both U.S. and foreign PWR plants, have been documented for more than 30 years, and led the NRC in 1988 to issue Generic Letter (GL) 88-05. This GL requested information from PWR licensees that would provide assurances that a program has been implemented consisting of systematic measures to ensure that boric acid corrosion does not lead to degradation of the assurance that the RCPB will have an extremely low probability of leakage, rapidly propagating failure or gross rupture. In addition, in 1995,

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EPRI issued the boric acid corrosion control handbook to provide comprehensive guidance to licensees on this subject.

There had also been two boric acid degradation events previously at DBNPS. One of these involved the head vent flange to Steam Generator No. 2 in 1993, while the other involved the pressurizer spray valve in 1998. In addition to these events, the plant had operated throughout most of the 1990s with a history of CRDM flange leakage that ultimately caused significant deposition of boric acid and corrosion products on the DBNPS RPV head. At some point in the latter half of the 1990s, the combination of flange leakage and leakage through VHP Nozzle 3 caused the formation of the wastage cavity that was discovered in March, 2002. As mentioned previously, the exact mechanism for the cavity formation has not been determined, but clearly involved corrosion due to the presence of boric acid. It is also likely that the degradation leading to the cavity formation had progressed over several years. As described elsewhere in this report, there were also advance signs that significant boric acid degradation was occurring in the DBNPS containment, most notably reddish-brown deposits on the containment air coolers and other components. As subsequently observed in videotapes documenting the condition of the DBNPS RPV head from 1998 forward, the accumulation of boric acid and corrosion products on the top of the head (particularly in the region of VHP Nozzle 3), precluded effective visual examination for leakage from cracked VHP nozzles.

2.3 Applicable Regulatory Requirements

There are a number of pertinent regulatory requirements. Several provisions of the NRC regulations and plant operating licenses (technical specifications) pertain to the issue of VHP nozzle cracking and boric acid corrosion. These include: the general design criteria (GDC) for nuclear power plants (Appendix A to 10 CFR Part 50), or, as appropriate, similar requirements in the licensing basis for a reactor facility; the requirements of 10 CFR 50.55a; and the quality assurance criteria of Appendix B to 10 CFR Part 50.

The applicable GDCs include GDC 14, GDC 31, and GDC 32. GDC 14 specifies that the reactor coolant pressure boundary (RCPB) have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. GDC 31 specifies that the probability of rapidly propagating fracture of the RCPB be minimized. GDC 32 specifies that components which are part of the RCPB have the capability of being periodically inspected to assess their structural and leak tight integrity.
NRC regulations detailed in 10 CFR 50.55a state that American Society of Mechanical Engineers (ASME) Class 1 components (which include VHP nozzles) must meet the requirements of Section XI of the ASME Boiler and Pressure Vessel Code. Table IWA-2500-1 of Section XI of the ASME Code provides examination requirements for VHP nozzles and references IWB-3522 for acceptance standards. IWB-3522.1(c) and (d) specify that conditions requiring correction include the detection of leakage from insulated components and discoloration or accumulated residues on the surfaces of components, insulation, or floor areas which may reveal evidence of borated water leakage, with leakage defined as "the through-wall leakage that penetrates the pressure retaining membrane." For through-wall leakage identified by visual examinations in accordance with the ASME Code, acceptance standards for the identified degradation are provided in IWB-3142. Specifically, supplemental examination (by surface or volumetric examination), corrective measures or repairs, analytical evaluation, and replacement provide methods for determining the acceptability of degraded components.

ASME Section XI, Table IWB-2500-1, requires that RCS leakage tests at nominal operating pressure be conducted prior to plant startup following each reactor refueling outage. Article IWA 5241 requires a direct visual examination, known as a VT-2, of the accessible external exposed surfaces of pressure retaining components for evidence of leakage from non-insulated components. Regarding insulated components, IWA-5242 states that VT-2 may be conducted without removing insulation by examining the accessible and exposed surface and joints of the insulation. When performing such examinations, the surrounding area shall be examined for evidence of leakage. Discoloration or residue on surfaces examined shall be given particular attention to detect evidence of boric acid accumulations from borated reactor coolant leakage. Corrective measures are specified in IWA-5250, which requires leakage sources of boric acid residues, and areas of general corrosion, to be located.. Article IWA-52050(b) also requires that components with areas of general corrosion that reduce the wall thickness by more than 10 percent shall be evaluated to determine whether the component may be acceptable for continued service, or whether repair or replacement is required.

Criterion IX of Appendix B to 10 CFR Part 50 states that special processes, including nondestructive testing, shall be controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements.

Criterion V of Appendix B to 10 CFR Part 50 states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Criterion V further states that instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Criterion XVI of Appendix B to 10 CFR Part 50 states that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. For significant conditions adverse to quality, the measures taken shall include root cause determination and corrective action to preclude repetition of the adverse conditions.

Plant technical specifications pertain to the issue of VHP nozzle cracking insofar as they require no through-wall reactor coolant system leakage.