Westinghouse Non-Proprietary Class 3

WCAP-15973-NP-A
Revision 0

February 2005

Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs

Westinghouse

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Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs

WOG Task Numbers 1131, 1170

February 2005

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Westinghouse Owners Group
Member Participation* for WOG Project Tasks 1131, 1170

Utility Member	Plant Site(s)	Participant	
		Yes	No
AmerenUE	Callaway (W)		✓
American Electric Power	D.C. Cook 1&2 (W)		✓
Arizona Public Service	Palo Verde Unit 1, 2, & 3 (CE)		✓
Constellation Energy Group	Calvert Cliffs 1 & 2 (CE)	✓	
Constellation Energy Group	Ginna (W)		✓
Dominion Connecticut	Millstone 2 (CE)	✓	
Dominion Connecticut	Millstone 3 (W)		✓
Dominion Virginia	North Anna 1 & 2, Surry 1 & 2 (W)		✓
Duke Energy	Catawba 1 & 2, McGuire 1 & 2 (W)		✓
Entergy Nuclear Northeast	Indian Point 2 & 3 (W)		✓
Entergy Operations South	Arkansas 2, Waterford 3 (CE)	✓	
Exelon Generation Co. LLC	Braidwood 1 & 2, Byron 1 & 2 (W)		✓
FirstEnergy Nuclear Operating Co	Beaver Valley 1 & 2 (W)		✓
Florida Power & Light Group	St. Lucie 1 & 2 (CE)	✓	
Florida Power & Light Group	Turkey Point 3 & 4, Seabrook (W)		✓
Nuclear Management Company	Prairie Island 1 & 2, Point Beach 1 & 2, Kewaunee (W)		✓
Nuclear Management Company	Palisades (CE)	✓	
Omaha Public Power District	Fort Calhoun (CE)	✓	
Pacific Gas & Electric	Diablo Canyon 1 & 2 (W)		✓
Progress Energy	Robinson 2, Shearon Harris (W)		✓
PSEG - Nuclear	Salem 1 & 2 (W)		✓
Southern California Edison	SONGS 2 & 3 (CE)		✓
South Carolina Electric & Gas	V.C. Summer (W)		✓
South Texas Project Nuclear Operating Co.	South Texas Project 1 & 2 (W)		✓
Southern Nuclear Operating Co.	Farley 1 & 2, Vogtle 1 & 2 (W)		✓
Tennessee Valley Authority	Sequoyah 1 & 2, Watts Bar (W)		✓
TXU Power	Comanche Peak 1 & 2 (W)		✓
Wolf Creek Nuclear Operating Co.	Wolf Creek (W)		✓

*** Project participants as of the date the final deliverable was completed. On occasion, additional members will join a project. Please contact the WOG Program Management Office to verify participation before sending this document to participants not listed above.**

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

January 12, 2005

Mr. Gordon Bischoff, Manager
Owners Group Program Management Office
Westinghouse Electric Company
P.O. Box 355
Pittsburgh, PA 15230-0355

SUBJECT: FINAL SAFETY EVALUATION FOR TOPICAL REPORT WCAP-15973-P, REVISION 01, "LOW-ALLOY STEEL COMPONENT CORROSION ANALYSIS SUPPORTING SMALL-DIAMETER ALLOY 600/690 NOZZLE REPAIR/REPLACEMENT PROGRAM" (TAC NO. MB6805)

Dear Mr. Bischoff:

By letter dated May 20, 2004 (ML041540226), the Westinghouse Owners Group (WOG) submitted Topical Report (TR) WCAP-15973-P, Revision 01, "Low-alloy Steel Component Corrosion Analysis Supporting Small-diameter Alloy 600/690 Nozzle Repair/Replacement Program" for the staff review. On November 30, 2004 (ML043090373), an NRC draft safety evaluation (SE) regarding our approval of WCAP-15973-P was provided for your review. By e-mail dated December 16, 2004, the WOG suggested some minor editorial changes to the draft SE which were fully adopted into the final SE, as discussed in the attachment to the final SE enclosed with this letter.

The staff has found that WCAP-15973-P, Revision 01, is acceptable for referencing in licensing applications for Combustion Engineering-designed pressurized water reactors to the extent specified and under the limitations delineated in the TR and in the enclosed SE. The SE defines the basis for acceptance of the TR.

Our acceptance applies only to material provided in the subject TR. We do not intend to repeat our review of the acceptable material described in the TR. When the TR appears as a reference in license applications, our review will ensure that the material presented applies to the specific plant involved. License amendment requests that deviate from this TR will be subject to a plant-specific review in accordance with applicable review standards.

In accordance with the guidance provided on the NRC website, we request that the WOG publish accepted proprietary and non-proprietary versions of this TR within three months of receipt of this letter. The accepted versions shall incorporate this letter and the enclosed SE between the title page and the abstract. They must be well indexed such that information is readily located. Also, they must contain historical review information, such as questions and accepted responses, draft SE comments, and original TR pages that were replaced. The accepted versions shall include a "-A" (designating accepted) following the TR identification symbol.

If future changes to the NRC's regulatory requirements affect the acceptability of this TR, Westinghouse Owners Group and/or licensees referencing it will be expected to revise the TR appropriately, or justify its continued applicability for subsequent referencing.

Sincerely,

Herbert N. Berkow

Herbert N. Berkow, Director
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Project No. 694

Enclosure: Safety Evaluation

cc w/encl:
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

WCAP-15973-P, REVISION 01, "LOW-ALLOY STEEL COMPONENT CORROSION ANALYSIS SUPPORTING SMALL-DIAMETER ALLOY 600/690 NOZZLE REPAIR/REPLACEMENT PROGRAM"

WESTINGHOUSE OWNERS GROUP

PROJECT NO. 694

1.0 INTRODUCTION

Vessels and piping in the reactor coolant pressure boundary of pressurized water reactors (PWRs) are fabricated either from A 302, Grade B; SA 533, Grade B; or SA 508, Class 2 low-alloy steels (for fabrication of vessels), or SA 516, Grade 70 carbon steel (for the fabrication of piping). These materials are classified as ferritic steel materials. These components are typically clad on their internal surfaces using austenitic stainless steels to isolate the ferritic material from the primary coolant, thereby minimizing corrosion and corrosion product release into the coolant. Alloy 600 nozzles that penetrate through these components are typically joined to the vessels or piping using partial penetrating J-groove welds that are fabricated from Alloy 82/182 weld materials. These welds penetrate completely through the cladding and partially into the ferritic portions of the vessels or piping. Therefore, in the as-built condition, the ferritic material is not exposed to the borated primary coolant water. Inservice industry experience has demonstrated that these Alloy 600 nozzles and Alloy 82/182 welds are susceptible to primary water stress corrosion cracking (PWSCC) resulting in through-wall/weld cracks. The half-nozzle and the mechanical nozzle seal assembly (MNSA) repairs leave the through-wall cracks intact and potentially leaves the ferritic portions of the vessel or piping exposed to borated water.

By safety evaluation (SE) dated February 8, 2002, the NRC staff reviewed and approved, with limitations, the use of Topical Report (TR) CE-NPSD-1198-P, Revision 00, "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Program" submitted by the Combustion Engineering Owners Group (CEOG) on February 15, 2001. The CEOG was integrated into the Westinghouse Owners Group (WOG) in 2002. Future references to the owners group will be made to as the WOG. This TR provided an evaluation on potential degradation mechanisms of these repaired components, which included corrosion, stress corrosion cracking and thermal fatigue.

By letter dated November 11, 2002, the WOG submitted TR WCAP-15973-P, Revision 00, "Low Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Program" for staff review and approval. The WOG seeks the staff's approval of the TR in order that licensees seeking relief to use half-nozzle or MNSA repair/replacement techniques may reference the TR as part of their basis for using the alternate repair methods on leaking Alloy 600 nozzles in the primary pressure boundary. The TR provides an evaluation on determining corrosion rates, stress corrosion cracking and thermal fatigue relevant to these alternative repair methods. A non-proprietary version of the TR was enclosed along with Calculation Report CN-CI-02-71 (Proprietary), entitled "Summary of Fatigue Crack Growth Evaluation Associated with Small Diameter Nozzles in CE Plants," dated October 28, 2002. This TR corrected errors in the thermal fatigue calculations reported in CE-NPSD-1198-P, Revision 00. These errors affect the predicted growth of thermal fatigue cracks in limiting locations. In addition, WCAP-15973-P, Revision 00, addressed concerns regarding boric acid corrosion discovered at Davis-Besse in response to NRC Bulletin 2001-01, and also revised the general corrosion rates. Clarifications were also made to the stress corrosion cracking evaluation.

By letter dated October 6, 2003, the WOG supplemented the information in the TR with additional information. However, by letter dated March 5, 2004, the WOG withdrew Revision 00 to the TR due to errors discovered in the supporting fatigue crack growth analyses. By letter dated May 20, 2004, the WOG submitted TR WCAP-15973, Revision 01, dated May 2004, and the supporting Westinghouse Calculation Report CN-CI-02-71, Revision 01, to correct the errors in Revision 00 of the TR and the calculation report. The WOG provided additional information on the calculation report by letter dated August 11, 2004.

2.0 REGULATORY REQUIREMENTS

Section 50.55a(g) of Title 10 of the *Code of Federal Regulations* (10 CFR) requires nuclear power facility piping and components to meet the applicable requirements of Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (hereafter referred to as the ASME Code). Currently, 10 CFR 50.55a endorses all versions of the ASME Code, Section XI up to the 1998 Edition through the 2000 Addenda. Although the exact wording may vary depending on the specific edition and addenda of the ASME Code used, Article IWA-4000 requires that existing flaws in ASME Code Class 1 components either be removed in their entirety or, if not removed, evaluated in accordance with the appropriate flaw evaluation provisions of Section XI of the ASME Code. For example, paragraph IWA-4310 of the 1995 Edition, with the 1995 and 1996 Addendum of Section XI to the ASME Code states:

> Defects shall be removed or reduced in size in accordance with this Paragraph. The component shall be acceptable for continued service if the resultant section thickness created by the cavity is equal to or greater than the minimum design thickness. If the resulting thickness is reduced below the minimum design thickness, the component shall be repaired or replaced in accordance with this Article. Alternatively, the defect removal area and any remaining portion of the flaw may be evaluated and the component accepted in accordance with the appropriate flaw evaluation rules of Section XI or the design rules of the Owner's Requirements and either the Construction Code, or Section III. The Repair/Replacement Program, Plan, and associated evaluation shall be subject to review in accordance with IWA-4140(c).

Therefore, if the flaw is to be left in service, an evaluation is required to be performed and reviewed by the NRC, as required by section IWA-4140(c) of the 1995 Edition, with the 1995 and 1996 Addendum of Section XI to the ASME Code, which states:

> The Repair/Replacement Program, Plans, and evaluations required by IWA-4150 shall be subject to review by enforcement and regulatory authorities having jurisdiction at the plant site.

In addition, paragraph IWB-3142.4 of the 1995 Edition, with the 1995 and 1996 Addendas of Section XI to the ASME Code provides acceptance requirements for flaws to be left in service as follows:

> Components containing relevant conditions shall be acceptable for continued service if an analytical evaluation demonstrates the component's acceptability. The evaluation analysis and evaluation acceptance criteria shall be specified by the Owner. Components accepted for continued service based on analytical evaluation shall be subsequently examined in accordance with IWB-2420(b) and (c).

IWB-2420(b) and (c) of the 1995 Edition, with the 1995 and 1996 Addendas of Section XI to the ASME Code provides information on performing successive inspections for flaws left in service and accepted by analytical evaluation:

> If components are accepted for continued service in accordance with IWB-3132.4 or IWB-3142.4, the areas containing flaws or relevant conditions shall be reexamined during the next three inspection periods listed in the schedule of the inspection program of IWB-2400. If the reexamination required by IWB-2400(b) reveals that the flaws or relevant conditions remain essentially unchanged for three successive inspection periods, the component examination schedule may revert to the original schedule for successive inspections.

Other editions of the ASME code provide similar guidance. In summary, the ASME Code requires either the removal of the flaw, or the performance of an analysis with subsequent examinations. This TR addresses the latter, by providing corrosion and fatigue analyses of the cracked Alloy 600 nozzle and/or Alloy 82/182 weld since the half-nozzle and MNSA repairs leave the flaw in service.

The discovery of leaks and nozzle cracking at the Davis-Besse Nuclear Power Station and other PWR plants has made clear the need for flaw evaluation guidelines for control rod drive mechanism (CRDM) type of penetrations and more effective inspections of reactor pressure vessel (RPV) heads and associated penetration nozzles. To ensure that the inspections are effective, the NRC issued Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," Information Notice 2003-02, "Recent Experience with Reactor Coolant System Leakage and Boric Acid Corrosion," and Order EA-03-009, "Issuance of Order Establishing Interim Inspection

Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors." Since there is limited flaw evaluation guidelines for these conditions, the NRC developed flaw evaluation guidelines for this application for appropriate use by the industry and the staff. The original guidelines were enclosed in the letter dated November 21, 2001, from the NRC to the Nuclear Energy Institute (NEI), and the revised guidelines were enclosed in the letter dated April 11, 2003, from the NRC to NEI.

The TR was reviewed in accordance with the requirements of 10 CFR 50.55a (Section XI of the ASME Code) and the April 11, 2003, guidelines.

3.0 EVALUATION

WCAP-15973-P, Revision 01, is only applicable to repairs/replacements of leaking Alloy 600 nozzles and/or Alloy 82/182 welds in the reactor coolant pressure boundary of Combustion Engineering (CE) plants using either the MNSA or half-nozzle repair/replacement techniques. The use of the half-nozzle or MNSA repair/replacement techniques of WCAP-15973-P, Revision 01 leaves the through-wall crack in the Alloy 600 nozzle and/or Alloy 82/182 J-groove weld intact and potentially allows the ferritic portions of the vessels or piping to be exposed to the borated reactor coolant. WCAP-15973-P, Revision 01, accomplishes the following objectives with respect to implementing these repair or replacement methods:

1. Provides an acceptable method for calculating the overall general/crevice corrosion rate for the internal surfaces of the low-alloy steel materials that are now potentially exposed to the reactor coolant, and for calculating the amount of time the ferritic portions of the vessel or piping would be acceptable if corrosive wall thinning occurs. (See Section 3.1 of this SE for the evaluation.)

2. Provides an acceptable method of calculating the thermal-fatigue crack-growth life of existing flaws in the Alloy 600 nozzles and/or Alloy 82/182 weld material into the ferritic portion of the vessels or piping. (See Section 3.2 of this SE for the evaluation.)

3. Provides acceptable bases and arguments for concluding that unacceptable growth of the existing flaw by stress corrosion into the vessel or piping is improbable. (See Section 3.3 of this SE for the evaluation.)

The main difference between the half-nozzle and the MNSA repair is that the half-nozzle provides a welded repair on the outside of the component, in contrast to the MNSA repair, which mechanically seals a leak or potential leak on the outside surface of the component. Since the complete alloy 600 nozzles are left in place, the MNSA repair is similar to the half-nozzle condition in that the cracked nozzle and/or weld will remain in place and the crevice regions will be filled with borated water. Therefore, the corrosion and crack growth evaluations of the half-nozzles also applies to the MNSA repairs. However, since this is a mechanical device in lieu of a weld, that provides both sealing and structural integrity for the leaking nozzle, additional justification is required to approve MNSA for a long-term repair. As discussed in the NRC letter dated December 8, 2003, to the WOG, an analysis of the pressure boundary component to which the MNSA is attached and an inservice inspection program to be maintained throughout the licensed life of the facility is required. As stated in a letter dated

February 18, 2004, the WOG is currently working with various Code Committees to resolve the NRC's concerns in order that the application of MNSAs can be made as a long-term repair. When these concerns are resolved, the corrosion and crack growth evaluations of WCAP-15973-P, Revision 01, with respect to the flaws left in service can be applied to the MNSA repair.

3.1 General and Crevice Corrosion Rate Evaluation (WCAP-15973-P, Revision 01)

The MNSA and half-nozzle repair/replacement designs will potentially leave the ferritic surfaces of the vessels or piping exposed to the borated reactor coolant. The WOG evaluates the potential for these surfaces to degrade by general or crevice corrosion in Section 2.0 of the TR. The WOG makes its general/creviced corrosion rate evaluation based on the relative chemistry and temperature conditions of the reactor coolant. According to a qualitative review of Figures 1 and 2 in the TR, exposure to the reactor coolant will be under crevice conditions for the MNSA designs and under bulk coolant conditions for the half-nozzle designs.

The WOG's overall corrosion rate for general corrosion of low-alloy or carbon steel materials is summarized in Equation 1 and Conclusion 1 of the TR and is based on a sum of contributing corrosion rate factors for normal operating conditions, startup conditions, and low temperature outage conditions. These "factors" are the multiplicative results of the corrosion rate values for operating conditions and the WOG's best estimate for the amount of time (as a percentage of total operating life) that a typical plant would operate in these modes. The WOG used Conclusions 2 and 3 of the TR to support the overall corrosion rate given in Conclusion 1.

The WOG used the results of laboratory corrosion studies as its bases for establishing the general corrosion rates for low-alloy or carbon steel materials during normal operating, startup, and cold shutdown modes of operation. The laboratory studies used for determining the bounding corrosion rate for normal operating conditions were performed under deaerated conditions, and simulated maximum boron, lithium, and oxygen levels in the reactor coolant under normal operating conditions for a CE-designed PWR. The laboratory studies used for determining the corrosion rates for low alloy or carbon steel materials during startup or cold shutdown conditions also simulated the boron, lithium, and oxygen levels for these conditions, but were made under aerated conditions.

During normal operating conditions, the reactor coolant system (RCS) is closed off from the reactor building environment, and the system is operated at temperatures in the range of 560-600°F and under hydrogen water chemistry conditions. At these temperatures, the concentration of dissolved oxygen in the coolant is normally maintained well below 150 parts per billion (ppb). During cold shutdown and startups, the RCS is normally opened up and exposed to the reactor building environment. Under these conditions, the concentration of dissolved oxygen in the RCS coolant is normally much higher than it would be during normal operating conditions, when the RCS is sealed off from the reactor building environment. Since the laboratory conditions for the corrosion studies were consistent with chemistry conditions in the reactor coolant during normal operating, startup, and cold-shutdown conditions, the staff concludes that the proposed corrosion rates for normal operating, startup, and cold shutdown conditions provide an acceptable basis for calculating the overall corrosion rate for ferritic carbon and low-alloy steel materials under the borated and hydrogen water chemistry.

conditions for the reactor coolant. The general corrosion rates for normal operating, startup, and cold shutdown conditions is based on limited laboratory and field data. Therefore, if new laboratory or field data become available that invalidate the bounding general corrosion rates given in the TR, the staff requests that the WOG submit an addendum to the TR that will provide a summary of the analyses performed on the new data and a new overall general corrosion rate calculation that is based on the results from these analyses.

The method for calculating the general overall corrosion rate is also dependent on the amount of time the plants (in terms of percentage of total plant life) are estimated to be operating in the normal operating, startup, and cold shutdown modes of operation, in addition to the corresponding corrosion rates during each of the modes of operation as discussed above. The amount of time in these modes of operation, which are normally provided in the design basis for the plant, may vary from plant-to-plant and from the times used by the WOG in Equation (1) of the TR. In this case, when the staff used a time at normal operation of 80 percent[1], the staff calculated a general overall corrosion rate value that was approximately 40 percent in excess of the corresponding value calculated by the WOG. This demonstrates that the overall general corrosion rate for determining the repair lives of the nozzles is dependent on the plant-specific times at normal operations, startups, and cold shutdowns of a given plant.

In addition, Section 2.2 of WCAP-15973-P, Revision 01, addressed concerns regarding boric acid corrosion discovered at Davis-Besse in response to NRC Bulletin 2001-01. The TR bases its conclusion that during plant operation, boric acid corrosion is low because there is no mechanism for concentrating boric acid in the crevice region and free oxygen does not exist. Davis-Besse and similar events involving corrosion of the RCS components and fasteners exposed to the containment atmosphere (containing free oxygen) are not applicable because of the dissimilarity in the environmental conditions. However, during shutdowns and refuelings, the corrosion rate will increase since the crevice region may be filled with aerated water. The report stated that some tests using SA 533 Grade B steel mockups which contained cracked nozzles produced corrosion rates of up to two inches per year in aerated water conditions. In addition, other laboratory data showed that corrosion rates in deaerated water are minimal. Therefore, if the nozzles are not leaking, or exposed to aerated water, these corrosion rates will be minimal. As stated above, the corrosion rates are dependent on the plant-specific times at normal operations, startups, and cold-shutdowns, as well as plant-specific configurations, and therefore must be demonstrated to be applicable on a plant-specific basis.

Licensees seeking to use the methods of the TR need to perform the following plant-specific calculations in order to confirm that the ferritic portions of the vessels or piping within the scope of the TR will be acceptable for service throughout the licensed lives of their plants (40 years if the normal licensing basis plant life is used or 60 years if the facility is expected to be approved for extension of the operating license):

1. Calculate the minimum acceptable wall thinning thickness for the ferritic vessel or piping that will adjoin to the MNSA repair or half-nozzle replacement.

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1 A significant number of licensees in the industry use 80 percent as the design basis for the amount of time at normal power operations. Use of this in the NRC's independent calculation of the overall corrosion rate for general or crevice-type corrosion is based on this time.

2. Calculate the overall general corrosion rate for the ferritic materials based on the calculational methods in the TR using the general corrosion rates listed in the TR for normal operations, startup conditions (including hot standby conditions), and cold shutdown conditions, and the respective plant-specific times (in-percentage of total plant life) at each of the operating modes.

3. Track the time at cold shutdown conditions to determine whether this time exceeds the assumptions made in the analysis. If these assumptions are exceeded, the licensees shall provide a revised analysis to the NRC, and provide a discussion on whether volumetric inspection of the area is required.

4. Calculate the amount of general corrosion-based thinning for the vessels or piping over the life of the plant, as based on the overall general corrosion rate calculated in Step 2 and the thickness of the ferritic vessel or piping that will adjoin to the MNSA repair or half-nozzle replacement.

5. Determine whether the vessel or piping is acceptable over the remaining life of the plant by comparing the worst case remaining wall thickness to the minimum acceptable wall thickness for the vessel or pipe.

Plant-specific engineering evaluations that have been calculated in accordance with these methods and that demonstrate that the ferritic materials will not be thinned by general corrosion to a size less than the minimum allowable wall thickness for the component are sufficient to satisfy the acceptability by analysis provisions of Section XI for defects induced by general corrosion or crevice corrosion.

3.2 Fatigue Crack Growth Evaluation (Including Supporting Calculation Report CN-CI-02-71, Revision 01)

The WOG's MNSA and the half-nozzle repair technique for small-bore nozzle repairs in hot-leg piping, pressurizer lower head instrument nozzle, pressurizer lower head heater sleeve, and pressurizer lower shells relocates the pressure boundary from the internal surface to the external surface while leaving the flaw in the internal J-groove weld and/or nozzle. To justify not removing the flaw, the WOG performed a flaw evaluation similar to the flaw evaluation procedures of Appendix A to Section XI of the ASME Code to demonstrate the structural integrity of the pressure boundary for the life of the plant (40 years).

As stated in Section 3.3 of WCAP-15973, Revision 01, a detailed evaluation of the fatigue crack growth analysis is provided in Calculation Report CN-CI-02-71, Revision 01. A typical flaw evaluation requires determination of the initial flaw size, the applied stress intensity factor ($K_{applied}$) values, fatigue crack growth, and stability of the final crack size. These elements have been revised significantly in Calculation Report CN-CI-02-71, Revision 01, which was transmitted to the NRC on May 20, 2004, to reflect (1) the responses to the staff's requests for additional information (RAI) as addressed in a letter dated October 6, 2003, (2) the inclusion of in-surges in heatup and cooldown transients, and (3) additional modifications in the flaw evaluation methodology initiated by the WOG and the licensee after submitting Revision 00 to Calculation Report CN-CI-02-71. Therefore, the staff's discussion focuses on information in

Calculation Report CN-CI-02-71, Revision 01, and the WOG's response to the staff's RAI regarding this revision, as addressed in a letter dated August 11, 2004. Calculation Report CN-CI-02-71, Revision 00, and the WOG's response to the staff's RAI regarding it will only be addressed when necessary. The technical elements of the flaw evaluation are evaluated by the staff in the following sections.

3.2.1 Initial Flaw Size

The initial flaw is assumed to be a double-sided crack that has propagated through the J-groove weld and touches the carbon steel material that comprises the pressure boundary. The staff examined Calculation Report CN-CI-02-71, Revision 01, initial crack size calculations for the above-mentioned four components and verified that each initial flaw size represents the radial cross section of the J-groove weld (the worst possible radial crack that could exist in the weld). This approach of characterizing a leaked flaw based on the worst assumption is consistent with those in approved applications of similar nature and has become standard industry practice now. Licensees seeking to reference this TR for future licensing applications need to demonstrate that the geometry of the leaking penetration is bounded by the corresponding penetration reported in Calculation Report CN-CI-02-71, Revision 01.

3.2.2 Applied Stress Intensity Factor Values

For a flaw subjected to fatigue crack growth or any type of stress-corrosion cracking (SCC), the final crack size is needed for determining the operating time for the unit with the flawed component. Since the crack growth equation is a function of the $K_{applied}$ value, selecting the appropriate $K_{applied}$ formula in the calculation is important in the crack growth evaluation. In this application, the WOG used the Raju-Newman formulation documented in NASA Technical Memorandum 85793, "Stress-Intensity Factor Equations for Cracks in Three-Dimensional Finite Bodies Subjected to Tension and Bending Loads." One of the staff's RAIs concerns the applicability of the Raju-Newman $K_{applied}$ solution to the current application, considering the differences between the Raju-Newman model and the current model regarding relative hole size and crack geometry. The WOG replied in its October 6, 2003, response that the subject geometries are within the applicability range of the Raju-Newman $K_{applied}$ solution for crack depth to length ratios of 0.2 to 2.0 and for crack depth to plate thickness ratios of less than 0.8. Actually, four applicability criteria are associated with this Raju-Newman solution. The staff examined the other two applicability criteria that the WOG did not address and found that the subject geometries satisfy the limit of less than 0.5 for the ratio of the extended hole size (hole radius + crack length) to the component length, but does not satisfy the lower limit of 0.5 for the ratio of the hole radius to the component thickness. Physically, this means that the subject geometries have more material ahead of the crack front than that of the Raju-Newman model, and therefore using the Raju-Newman solution is conservative in this application.

Revision 01 to Calculation Report CN-CI-02-71 reveals that the calculated $K_{applied}$ values at the final flaw sizes for the four components differ significantly from their corresponding values in Revision 00. According to the August 11, 2004, response to the staff's RAI, the WOG attributed three factors for this change: (1) the use of a realistic heat transfer coefficient, instead of infinity, in the thermal analysis, (2) the use of a stress distribution postprocessing methodology based on full three dimensional finite element calculations, instead of the peak stress value, and (3) the use of one crack model for instrument nozzles and one for heater sleeves, instead of one bounding model for both types of penetrations. These changes are justified because these actions simply take excessive conservatism out from the model and make the revised model more realistic. All three changes have the effect of reducing the calculated $K_{applied}$ values.

3.2.3 Fatigue Crack Growth

Fatigue crack growth of the flaw is calculated over a plant life of 40 years and is based on transients and cycles specified in design specifications for a typical CE plant for normal (Level A), upset (Level B), emergency (Level C), and faulted (Level D) conditions. Calculation Report CN-CI-02-71, Revision 01, further combines similar transients and eliminates relatively insignificant transients to simplify the fatigue crack growth calculation. The staff considers this simplification reasonable because all important transients such as heatup/cooldown, leak tests, and operating basis earthquake for hot legs have been captured. Turbine/reactor trips, which were included in Revision 00 to Calculation Report CN-CI-02-71 were not considered in Revision 01 because the calculations associated with Revision 00 showed only minor contribution from these transients. Hence, fatigue crack growth of the assumed flaw documented in Revision 01 is based on 500 cycles of a combined transient composed of heatup, cooldown, and leak test. The staff accepts the current transient and cycle selection since (1) inclusion of in-surges in the heatup and cooldown transients, which makes the transients more severe than those of Revision 00, represents a more realistic plant operation, and (2) the 500 heatup, cooldown, and test cycles are conservative for a 40-year operation.

Figure 6-2 (a) of Calculation Report CN-CI-02-71, Revision 01 depicts three curves: (1) the heatup curve (100°F/hr) with an in-surge, (2) the cooldown curve (100°F/hr) with two in-surges, and (3) the bi-rate (200°F/hr and 75°F/hr) cooldown curve. The first two curves are for the fatigue crack growth calculation, and the last curve in addition to the cooldown curve with the large in-surge are considered for the stability analysis of the final flaw. The pressure of these transients is based on the pressurizer saturated pressure plus 200 psi ($P_{saturated}$ + 200 psi). These generic transients are representative, but may not be bounding. Therefore, applicants who use this TR for future licensing purposes need to demonstrate that their plant-specific pressure and temperature profiles in the pressurizer water space for the limiting curves (cooldown curves) do not exceed the analyzed profiles shown in Figure 6-2 (a) of Calculation Report CN-CI-02-71, Revision 01.

The fatigue crack growth rate used in the calculations is Figure A-4300-2 of Section XI of the 1992 Edition of the ASME Code. This curve applies to carbon and low alloy ferritic steels exposed to a water environment and is considered by the staff to be appropriate for this application. Using the ASME fatigue curve and the calculated $K_{applied}$ value for the assumed initial crack geometry, the crack growth rate, and subsequently the crack growth for the first cycle can be determined. This crack growth was added to the assumed initial crack geometry to arrive at a revised crack geometry for the next round of calculation of $K_{applied}$, crack growth, and the revised crack geometry. This process is repeated cycle after cycle until all transient cycles have been exhausted. The revised crack geometry at the end of the last transient cycle is the final crack geometry.

3.2.4 Final Crack Stability Evaluation

The final step in Calculation Report CN-CI-02-71, Revision 01, consists of a flaw evaluation involving the calculation of the driving force and fracture resistance for the final flaw size. When linear elastic fracture mechanics (LEFM) is applicable, the driving force is the $K_{applied}$ and the fracture resistance is the plain strain fracture toughness (K_{Ic}) and the crack arrest fracture toughness (K_{Ia}). When elastic-plastic fracture mechanics (EPFM) is applicable, the driving force is $J_{applied}$ and its slope $\partial J_{applied} / \partial a$, and the fracture resistance is $J_{0.1}$ of the J-R curve ($J_{material}$) at a crack extension of 0.1 inch and the slope $\partial J_{material} / \partial a$ at the intersection of $J_{applied}$ and $J_{material}$. The crack stability evaluation examines the stability of a crack using either the LEFM criteria specified in IWB-3612 of Section XI of the ASME Code or the EPFM criteria specified in Regulatory Guide (RG) 1.161, "Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less than 50 ft-lb," and Appendix C to Section XI of the ASME Code. The LEFM methodology, as described in Report CN-CI-02-71, Revision 01, is in accordance with Appendix A to Section XI of the ASME Code, and is therefore acceptable to the staff. However, the staff has concerns with the proposed EPFM methodology in two areas.

First, the WOG proposed to use a structural factor of 3 on $J_{applied}$ for the EPFM analysis. The staff believes that for current applications (flaws being identified through leaking), it is more appropriate to use the structural factors for detected flaws such as those specified for the EPFM analysis for piping, as appeared in Appendix C to Section XI of the ASME Code. Appendix C specifies 2.7 and 2.3 as structural factors for membrane and bending stresses for piping with detected flaws under the fracture modes of ductile fracture and plastic collapse. This is equivalent to structural factors of 7.29 and 5.29 on $J_{applied}$. This staff concern prompted the WOG to provide a sensitivity analysis in the August 11, 2004, response, using structural factors up to 9.0 in the crack stability evaluation. The results of the sensitivity analysis plotted in Figures 4 and 5 of the response demonstrate that the RG 1.161 criteria of $J_{applied} < J_{0.1}$ and $\partial J_{applied} / \partial a < \partial J_{material} / \partial a$ at $J_{applied} = J_{material}$ are satisfied for both the pressurizer lower shell and the pressurizer lower head heater sleeves, even when a structural factor of 9 on $J_{applied}$ is used.

The second staff concern is that the proposed methodology did not apply a margin factor of 0.749 to the J-R curve as required by RG 1.161. This is not appropriate. However, the staff's independent assessment indicates that after reducing the J-R curves of Figures 4 and 5 to 0.749 of their presented values, RG 1.161 criteria are still met.

Therefore, the calculated values using the EPFM methodology in Calculation Report CN-CI-02-71, Revision 01, meet the RG 1.161 criteria based on the WOG's sensitivity analysis, and the staff's independent assessment using a structural factor of 7.29 on $J_{applied}$ and a material margin factor of 0.749 on $J_{material}$. Licensees may use these bounding values when referencing this TR. However, if the plant-specific application is not bounded by the analysis in Calculation Report CN-CI-02-71, Revision 01, the EPFM methodology may only be used for conducting the plant-specific analysis if adjusted using a structural factor of 7.29 on $J_{applied}$ and a material margin factor of 0.749 on $J_{material}$.

In summary, the EPFM results for pressurizer lower shell and pressurizer lower head heater sleeves, which are documented in the WOG's August 11, 2004, response, are acceptable because they meet the RG 1.161 criteria with a structural factor that is equivalent to that used in Appendix C to Section XI of the ASME Code. Further, the LEFM results tabulated in Tables 2-2, 2-4, 2-6, and 2-8 of Calculation Report CN-CI-02-71, Revision 01, for the hot-leg piping, pressurizer lower head instrument nozzles, pressurizer lower head heater sleeves, and pressurizer lower shell are also acceptable because they meet ASME Code specified criteria with additional margins. Based on the above evaluation, the staff has determined that the crack can be left in the J-groove weld at small-bore locations in the pressurizer and hot-leg piping for a plant life of 40 years.

For licensees who plan to use this TR for future licensing purposes need to demonstrate the following:

1. The geometry of the leaking penetration is bounded by the corresponding penetration reported in Calculation Report CN-CI-02-71, Revision 01.

2. The plant-specific pressure and temperature profiles in the pressurizer water space for the limiting curves (cooldown curves) do not exceed the analyzed profiles shown in Figure 6.2 (a) of Calculation Report CN-CI-02-71, Revision 01.

3. The plant-specific Charpy upper-shelf energy (USE) data showing a USE value of at least 70 ft-lb to bound the USE value used in the analysis. If the plant-specific Charpy USE data does not exist and the licensee plans to use Charpy USE data from other plants' pressurizers and hot-leg piping, then justification (e.g., based on statistical or lower bound analysis) has to be provided.

If the plant-specific application is not bounded by the analysis in Calculation Report CN-CI-02-71, Revision 01, the EPFM methodology may be used if adjusted using a structural factor of 7.29 on $J_{applied}$ and a material margin factor of 0.749 on $J_{material}$.

3.3 Stress Corrosion Cracking (WCAP-15973-P, Revision 01)

In Conclusion 4 of WCAP-15973-P, Revision 01, the WOG concluded that growth of existing flaws into the ferritic portions of the vessels or piping by stress corrosion was not plausible. The WOG's analysis for supporting this conclusion is provided in Section 3.6 of the TR. In this section, the WOG used the following arguments as its bases for concluding that there is a low probability for growing the existing cracks in the original weld metal and/or nozzle by stress corrosion into the ferritic material:

- During normal operations of the RCS in CE-designed reactors, hydrogen overpressure in the RCS significantly reduces the impurity levels of dissolved oxygen to a concentration less than 10 ppb. At these levels, the electro-chemical potential of the coolant is significantly less than required to grow a existing crack by stress corrosion.

- Even if high oxygen concentrations exist in the crevice during the initial stages of normal operations, the oxygen levels will quickly be reduced as a result of iron oxide formation on the surfaces of the ferritic steel. Since the oxygen levels in the bulk-coolant are typically less than 10 ppb during normal operations, there is no mechanism to replenish oxygen in the crevice region, and as a result the low-oxygen condition in the crevice region will quickly be re-established. Thus, the potential to grow the existing cracks by a stress corrosion mechanism will be low.

- Other contaminants (copper ions, sulfates, halides, etc.) that could increase the potential for cracks to grow by stress corrosion are also maintained at extremely low concentrations during normal operations.

The staff typically uses -200 Mev as the threshold potential for initiating and growing cracks by stress corrosion. At chemical potentials above this value, the staff considers initiation and growth of cracks by stress corrosion to be plausible. When the chemical potential of the reactor coolant is controlled to magnitudes below this value, the staff considers the potential for cracks to initiate and grow by stress corrosion to be significantly reduced.

At a typical PWR, control of contaminants that could lead to chemical potentials above -200 MeV is accomplished by the combined efforts of the plant operators and chemistry personnel. CE-designed reactors do not have any copper alloys in their RCS, therefore incursion of copper ion contaminants is typically not an issue for CE-designed reactors. In addition, licensees maintain the RCS chemistry by use of the chemical and volume control system as the method for controlling oxygen, halide and sulfate contaminants to low levels. This includes the use of ion exchangers to purify the reactor coolant. Plant chemistry procedures require plant chemistry personnel to monitor the contaminant levels of the RCS at regular daily intervals. Implementation of design changes to better ion exchange resins and improve chemical monitoring equipment have enabled licensees to control the levels of dissolved oxygen to concentrations less than 10 ppb, and halide and sulfate contaminants to concentrations well below the maximum acceptable levels referred to in the Electric Power Research Institute (EPRI) PWR Primary Water Chemistry Guidelines (i.e., well below 150 ppb). Licensees owning CE-designed plants maintain a significant hydrogen overpressure on their RCS. These practices allow the licensees for these facilities to maintain the electro-chemical potential of the reactor coolant at levels below -200 Mev. The staff therefore concurs that the probability for growing the existing flaws by stress corrosion is extremely low at these facilities.

In addition, Section 3.6.4 of the TR provides field experience which is consistent with the laboratory observations that SCC into the ferritic portion of the component is not likely to occur at CE plants. For example, in December 2000, an Oconee-1 CRDM nozzle exhibited stress corrosion cracks in the Alloy 82 weld that propagated through the weld and also extended to the Alloy 600 nozzle. However, the crack arrested when it reached the ferritic vessel head material. Another example was the occurrence of PWSCC in the weld between a pressurizer relief valve nozzle and a safe-end at the Japanese plant, Tsuruga-2. The cracking was discovered in the weld metal and buttering, which is a nickel based alloy. However, destructive examination showed that the crack extended to the interface between the weld and low alloy steel nozzle, but did not extend into the low alloy steel. Therefore, current industry experience is consistent with current laboratory observations that SCC into the ferritic portion is not likely to occur.

Licensees seeking to implement MNSA repairs or half-nozzle repairs may use the WOG's stress corrosion assessment as the bases for concluding that existing flaws in the weld metal will not grow by stress corrosion if they conduct appropriate plant chemistry reviews and if they can demonstrate that a sufficient level of hydrogen overpressure has been implemented for the

RCS, and that the oxygen and halide/sulfate concentrations in the reactor coolant have been typically maintained at levels below 10 ppb and 150 ppb, respectively. During the outage in which the half-nozzle or MNSA repairs are scheduled to be implemented, licensees adopting the TR's stress corrosion crack growth arguments will need to review their plant-specific RCS coolant chemistry histories over the last two operating cycles for their plants, and confirm that these conditions have been met over the last two operating cycles. Plant chemistry records are covered under the scope of 10 CFR 50.70 as being items that may be designated for inspection by the NRC.

4.0 CONCLUSIONS AND CONDITIONS

The staff's review of the methods in WCAP-15973-P, Revision 01, indicates that the WOG's methods and analyses in the TR are generally acceptable. Specifically, WCAP-15973-P, Revision 01, accomplishes the following objectives with respect to implementing these repair or replacement methods:

1. Provides an acceptable method for calculating the overall general/crevice corrosion rate for the internal surfaces of the low-alloy or carbon steel materials that will now be exposed to the reactor coolant, and for calculating the amount of time the ferritic portions of the vessel or piping would be acceptable if corrosive wall thinning had occurred,

2. Provides an acceptable method of calculating the thermal-fatigue crack-growth life of existing flaws in the Alloy 600 nozzles and/or Alloy 82/182 weld material into the ferritic portion of the vessels or piping, and

3. Provides acceptable bases and arguments for concluding that unacceptable growth of the existing flaw by stress corrosion into the vessels or piping is improbable.

The staff's conclusions and conditions regarding the WOG's general corrosion assessment, thermal-fatigue crack growth assessment, and stress corrosion cracking growth assessment are provided below in Sections 4.1, 4.2, and 4.3, respectively.

4.1 General Corrosion Assessment

The calculation of the general overall corrosion rate for the ferritic materials is dependent on both the individual general corrosion rates for normal operating, startup (including hot-standby), and coldshutdown conditions provided in Section 2.3.4 of the TR, and on the plant-specific times (in terms of percentage of total plant life) that a respective nuclear plant is estimated to operate in each of these operating modes. When the staff used a time at normal operation of 80 percent, the staff calculated a general overall corrosion rate that was 40 percent higher than the value calculated by the WOG. Therefore, the general overall corrosion rate proposed in Equation 1 of the TR may or may not be conservative, depending on what the plant-specific times at normal operating, startup (including hot standby), and cold shutdown conditions are. Licensees seeking to use the methods of the TR will need to perform the following plant-specific calculations in order to confirm that the ferritic portions of the vessels or piping within the scope of the TR will be acceptable for service throughout the licensed lives of their plants

(40 years if the normal licensing basis plant life is used or 60 years if the facility is expected to be approved for extension of the operating license):

1. Calculate the minimum acceptable wall thinning thickness for the ferritic vessel or piping that will adjoin to the MNSA repair or half-nozzle repair.

2. Calculate the overall general corrosion rate for the ferritic materials based on the calculational methods in the TR, the general corrosion rates listed in the TR for normal operations, startup conditions (including hot standby conditions), and cold shutdown conditions, and the respective plant-specific times (in-percentage of total plant life) at each of the operating modes.

3. Track the time at cold shutdown conditions to determine whether this time does not exceed the assumptions made in the analysis. If these assumptions are exceeded, the licensees shall provide a revised analysis to the NRC, and provide a discussion on whether volumetric inspection of the area is required.

4. Calculate the amount of general corrosion-based thinning for the vessels or piping over the life of the plant, as based on the overall general corrosion rate calculated in Step 2 and the thickness of the ferritic vessel or piping that will adjoin to the MNSA repair or half-nozzle repair.

5. Determine whether the vessel or piping is acceptable over the remaining life of the plant by comparing the worst case remaining wall thickness to the minimum acceptable wall thickness for the vessel or pipe.

Plant-specific engineering evaluations that have been calculated in accordance with these methods and that demonstrate that the ferritic materials will not be thinned by general corrosion to a size less than the minimum allowable wall thickness for the component over the life of the plant (40 years if the normal licensing basis plant life is used or 60 years if the facility is expected to be approved for extension of the operating license) will be sufficient to satisfy the acceptability by analysis provisions of Section XI of the ASME Code for defects induced by general corrosion or crevice corrosion.

4.2 Thermal-Fatigue Crack Growth Assessment

The staff determined that the WOG's methods for calculating the thermal-fatigue repair life of the existing flaws in the original weld metal was consistent with the methods of Appendix A to Section XI of the ASME Code. Licensees seeking to reference this TR for future licensing applications need to demonstrate that:

1. The geometry of the leaking penetration is bounded by the corresponding penetration reported in Calculation Report CN-CI-02-71, Revision 01.

2. The plant-specific pressure and temperature profiles in the pressurizer water space for the limiting curves (cooldown curves) do not exceed the analyzed profiles shown in

Figure 6-2 (a) of Calculation Report CN-CI-02-71, Revision 01, as stated in Section 3.2.3 of this SE.

3. The plant-specific Charpy USE data shows a USE value of at least 70 ft-lb to bound the USE value used in the analysis. If the plant-specific Charpy USE data does not exist and the licensee plans to use Charpy USE data from other plants' pressurizers and hot-leg piping, then justification (e.g., based on statistical or lower bound analysis) has to be provided.

If the plant-specific application is not bounded by the analysis in Calculation Report CN-CI-02-71, Revision 01, the EPFM methodology may be used as adjusted in Section 3.2.4 of this SE, which uses a structural factor of 7.29 on $J_{applied}$ and a material margin factor of 0.749 on $J_{material}$.

Based on the above evaluation, the staff has determined that the crack can be left in the J-groove weld at small-bore locations for a plant life of 40 years. However, if the licensee plans on using this alternative beyond the 40 years and through the license renewal period, the thermal fatigue crack growth analysis shall be re-evaluated to include the extended period, as applicable, and submitted as a time limited aging analysis in their license renewal application as required by 10 CFR 54.21(c)(1).

4.3 Stress Corrosion Crack Growth Assessment

The WOG used water chemistry and contaminant arguments as its bases for concluding that growth of the existing flaws by stress corrosion was not a plausible mechanism. Based on the staff's assessment given in Section 3.3 of this SE, the staff concurs that the probability for growing the existing flaws by stress corrosion into carbon or low alloy steels will be low as long as concentrations of dissolved oxygen, halide, sulfate, or other harmful contaminants is sufficiently controlled at the plants, and as long as hydrogen water chemistry is implemented at the plants. Licensees seeking to implement MNSA repairs or half-nozzle replacements may use the WOG's stress corrosion assessment as the bases for concluding that existing flaws in the weld metal will not grow by stress corrosion if they meet the following conditions:

1. Conduct appropriate plant chemistry reviews and demonstrate that a sufficient level of hydrogen overpressure has been implemented for the RCS, and that the contaminant concentrations in the reactor coolant have been typically maintained at levels below 10 ppb for dissolved oxygen, 150 ppb for halide ions, and 150 ppb for sulfate ions.

2. During the outage in which the half-nozzle or MNSA repairs are scheduled to be implemented, licensees adopting the TR's stress corrosion crack growth arguments will need to review their plant-specific RCS coolant chemistry histories over the last two operating cycles for their plants, and confirm that these conditions have been met over the last two operating cycles.

4.4 Other Considerations

The WOG's general corrosion rates for normal operations, startups, and cold shutdown conditions, as applied in Equation 1 of the TR, are considered by the staff to be acceptable, as long as the existing corrosion data used to determine the bounding rates is applicable. If additional laboratory or field data becomes available that invalidates the TR's general corrosion rate values for normal operations, startups, and cold shutdown conditions, the WOG should send in an addendum to the TR that evaluates the impact of the new data of the corrosion rate values for normal operations, startups, and cold-shutdown conditions, and that provides a new overall general corrosion rate assessment for the ferritic components under assessment.

The WOG's thermal fatigue crack growth analysis is only applicable to the evaluation of a single flaw. Should the WOG desire to extend the scope of its thermal-fatigue crack growth analysis to the analysis of multiple cracks in near proximity to one another, the WOG is requested to submit an appropriate addendum to the TR that provides the new thermal-fatigue crack growth assessment for the multiple flaw orientation.

The scope of WCAP-15973-P, Revision 01, does not address any welding considerations for the MNSA or half-nozzle designs. Licensees seeking to implement half-nozzle replacements or MNSA repairs of their Alloy 600 nozzles will need to assess the welding aspects of the design and may need to submit a relief request to implement the alternatives to the requirements of the ASME Code, Section XI as required by 10 CFR 50.55a.

The staff's review of the corrections to the flaw evaluation, changes in corrosion rate and clarification of the stress corrosion cracking in carbon and low alloy steels to WCAP-15973-P, Revision 01, indicates that the changes in the evaluation and analyses are generally acceptable. The requirements addressed in Section 4.0 of this SE must be addressed, along with the following, when this TR is used as the basis for the corrosion and fatigue crack growth evaluation when implementing a half-nozzle or MNSA repair:

1. Licensees using the MNSA repairs as a permanent repair shall provide resolution to the NRC concerns addressed in the NRC letter dated December 8, 2003, from H. Berkow to H. Sepp (ADAMS Accession No. ML033440037) concerning the analysis of the pressure boundary components to which the MNSA is attached, and the augmented inservice inspection program.

2. Currently, half-nozzle and MNSA repairs are considered alternatives to the ASME Code, Section XI. Therefore, licensees proposing to use the half-nozzle and MNSA repairs shall submit the required information contained in WCAP-15973-P, Revision 01, by the conditions of this SE, to the NRC as a relief request in accordance with 10 CFR 50.55a.

Attachment: Resolution of Comments

Principal Contributors: J. Honcharik
C. F. Sheng

Date: JANUARY 12, 2005

RESOLUTION OF WOG COMMENTS ON DRAFT SAFETY EVALUATION FOR TOPICAL REPORT WCAP-15973-P, REVISION 01, "LOW-ALLOY STEEL COMPONENT CORROSION ANALYSIS SUPPORTING SMALL-DIAMETER ALLOY 600/690 NOZZLE REPAIR/REPLACEMENT PROGRAM"

By e-mail dated December 16, 2004, the Westinghouse Owners Group (WOG) suggested some minor editorial changes to the NRC draft safety evaluation (SE) for WCAP-15973-P, Revision 01, "Low-alloy Steel Component Corrosion Analysis Supporting Small-diameter Alloy 600/690 Nozzle Repair/Replacement Program," which was provided to the WOG for their review on November 30, 2004. The following is the staff's resolution of the WOG comments.

WOG Comments:

(1) SE page 1, line 3 states "...SA 508, Grade B" -- this material should be labeled "SA 508, Class 2."

(2) SE page 10, end of line 1 contains a revision bar -- delete this bar.

(3) SE page 10, line 5, correct "resistence" to "resistance."

NRC Action: All these minor editorial comments were fully adopted into the final SE.

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ACRONYMS AND ABBREVIATIONS

ANO	Arkansas Nuclear One
ASME	American Society of Mechanical Engineers
BWR	Boiling Water Reactor
CE	Combustion Engineering
CEOG	CE Owners Group
CR	Corrosion Rate
ID	Inside Diameter
IN	Increase in Diameter
K_I	Stress Intensity Factor
MNSA	Mechanical Nozzle Seal Assembly
OBE	Operating Basis Earthquake
OD	Outside Diameter
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RTD	Resistance temperature Detector
SCC	Stress Corrosion Cracking
SSE	Safe Shutdown Earthquake
UT	Ultrasonic Test
WOG	Westinghouse Owners Group

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EXECUTIVE SUMMARY

Small-diameter NiCrFe Alloy 600 nozzles, such as hot leg piping RTD and sampling nozzles, pressurizer instrumentation nozzles, and pressurizer heater sleeves in CE Nuclear Power designed pressurized water reactors have developed leaks or partial through-wall cracks as a result of primary water stress corrosion cracking. The residual stresses imposed by the partial-penetration welds between the nozzles and the low alloy or carbon steel components are sufficient to cause crack initiation and propagation.

Two techniques, the "half-nozzle" weld repair and the mechanical nozzle seal assembly (MNSA) are currently used to repair or replace leaking Alloy 600 nozzles, and as preventive repairs on nozzles that may leak in the future. In the "half-nozzle" technique, the Alloy 600 nozzle is cut outboard of the partial-penetration weld and replaced with a short Alloy 690 nozzle section that is welded to the component outside surface. Mechanical nozzle seal assemblies are installed to mechanically seal a leaking nozzle at the outer surface of the component. In either technique, the crevices between the nozzles and components will fill with primary coolant and the flaws that resulted in primary coolant leakage will remain, although leakage will no longer be possible. This report evaluates the effect of component corrosion resulting from primary coolant in the crevice region on component integrity and evaluates the effects of propagation of the flaws left in place by fatigue crack growth and stress corrosion cracking mechanisms.

This revised report was prepared to correct errors in the calculations supporting the original report and to incorporate conditions not included in the calculations supporting the original report. An error in the program for calculating fatigue crack growth has been corrected and all crack growth analyses have been repeated. The stress analyses and fracture mechanics evaluations supporting the original report did not include the effects of the pressurizer support skirt. The support skirt effects were incorporated into the stress and fracture mechanics analyses of the pressurizer lower head. Similarly, the original calculations did not address the effect of periodic insurges of coolant on the pressurizer lower head. Previous work indicates that such insurges can and do occur during plant heat-ups and cool-downs. The heat-up/cool-down transients have been modified to include insurges and the fatigue crack growth calculations repeated.

This revised report provides bounding analyses for the maximum material degradation estimated to result from corrosion of the carbon or low alloy steel in the crevices between the nozzles and components. Results show that the quantity of material lost does not exceed ASME code limits. The report also provide results of fatigue crack growth evaluations and crack stability analyses for pressurizer heater sleeves and instrument nozzles and hot leg pipe nozzles, including the effects of the support skirt and pressurizer in-surges. The revised results indicate that the ASME Code acceptance criteria for crack growth and crack stability are met. Further, available laboratory data and field experience indicate that continued propagation of cracks into the carbon and low alloy steels by a stress corrosion mechanism is unlikely.

Half-nozzle replacement and mechanical nozzle seal assemblies are shown to be effective repair/replacement methods for leaking small-diameter nozzles from a corrosion, stress corrosion and fatigue crack growth assessment perspective. Corrosion of carbon and low alloy steels will be within Code limits and it is acceptable to leave a flaw in place in small diameter Alloy 600 nozzles and partial penetration welds for the balance of plant life.

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1 INTRODUCTION

1.1 PURPOSE

The purpose of this revised report is to demonstrate that unacceptable degradation of carbon or low alloy steel (base metal) does not occur when small diameter NiCrFe Alloy 600 nozzles in the primary pressure boundary of Combustion Engineering (CE) plants are repaired/replaced using the "half-nozzle" repair technique or mechanical seal nozzle assemblies (MNSAs). In these repairs, the carbon and low alloy steel base metals in the piping and pressurizers, which are normally clad with corrosion resistant materials, are left exposed to primary coolant. In addition, the original flaw that caused the leakage will be left in place and will continue to be subjected to stresses and temperature which could continue to propagate the flaws into the carbon and low alloy steel component material. The types of degradation evaluated in this report include general corrosion from exposure to primary coolant, stress corrosion cracking, and fatigue crack growth.

Subsequent to completion of the calculations supporting the original report, an error was discovered in the program used for determining crack propagation. Also, the original stress and fracture mechanics analyses did not consider the effects of the pressurizer support skirt, which resulted in under prediction of stresses. Further, the transients evaluated in the original report did not include the effects of pressurizer insurges that can and do occur during plant heat-ups and cool-downs. As a result, the calculations were repeated. This revised report presents the results of the new calculations and assesses their effects on fatigue crack growth and crack stability.

1.2 BACKGROUND

Primary water stress corrosion cracking (PWSCC) of Alloy 600 nozzles in CE plants first occurred in 1986 when a leaking pressurizer instrument nozzle was discovered at San Onofre-3. Most of the CE plants have experienced nozzle or heater sleeve leaks since 1986. The first leaks in Alloy 600 nozzles were in pressurizer instrument nozzles and heater sleeves where operating temperatures are the highest (Reference 1). This was expected since laboratory testing indicated that primary water stress corrosion cracking (PWSCC) is temperature dependent. Later, leaking or cracked nozzles were discovered at several plants in hot leg piping applications where temperatures are lower.

1.3 ALLOY 600 PROGRAM

There are several applications of small diameter NiCrFe Alloy 600 nozzles within the primary coolant pressure boundaries of CE PWRs. These applications include pressurizer instrumentation nozzles and heater sleeves, piping RTD and sampling nozzles, steam generator instrumentation nozzles, and reactor vessel head vent lines and leakage monitor tubes. Alloy 600 nozzle materials were procured as either pipe (ASME SB-167) for the heater sleeves, vent lines and leakage monitor tubes, or as bar stock (ASME SB-166) for all other nozzles. References 2 and 3 present the available materials properties and installation data for all nozzle applications of Alloy 600 in CE designed PWRs.

The Combustion Engineering Owners Group (CEOG) initiated an Alloy 600 program after the discovery of leaking pressurizer heater sleeves and a pressurizer instrumentation nozzle at Calvert Cliffs-2 in 1989. The objectives of this program were to identify the causative conditions for nozzle and heater sleeve

PWSCC, identify other locations where PWSCC might occur, and address the safety implications associated with nozzle cracking. The results (Reference 4) of this program indicated that:

1. circumferential cracking of a nozzle is unlikely,
2. cracks will be axial, near the partial penetration weld, and contained within the wall of the component,
3. cracks will not become unstable (leakage will gradually increase with time and should be detected),
4. visual inspection is the best inspection method for detecting leaking nozzles.

These findings indicated that nozzle cracking was not a safety issue, but could be an economic issue because of the outages and activities to replace or repair leaking nozzles.

A review of the CEOG program products and plant experience since the completion of the CEOG program also indicated that:

a,b,c

Available laboratory data and field experience suggest that there may be future occurrences of PWSCC in Alloy 600 nozzles. As a result, several plants have initiated programs to replace, or take preventive measures for, nozzles in the pressurizers or hot leg piping. Two currently used nozzle replacement or repair techniques are the "half-nozzle" repair and the mechanical nozzle seal assembly (MNSA). Both techniques have been used to repair/replace leaking nozzles and as a preventive measure for non-leaking nozzles.

In the "half-nozzle" repair, nozzles are cut outboard of the partial penetration weld between the nozzles and pressurizer shell or pipe wall. The cut sections of the Alloy 600 nozzles are replaced with short sections (half-nozzles) of NiCrFe Alloy 690 which are welded to the outside surfaces of the pressurizers or pipes. The remainder of the Alloy 600 nozzles, including the partial penetration welds, remains in place (Figure 1).

With the MNSA repair (Figure 2), a leak or a potential leak is mechanically sealed on the outside surface of the pressurizer or pipe. The complete Alloy 600 nozzles are left in place.

Small gaps of 1/8 inch or less remain between the remnants of the Alloy 600 nozzles and the new Alloy 690 nozzles in the half-nozzle repair. As a result, primary coolant (borated water) will fill the crevice between the nozzle and the wall of the pressurizer or pipe. Low alloy and carbon steels used for reactor coolant system components are clad with stainless steel to minimize corrosion resulting from exposure to borated primary coolant. Since the crevice regions are not clad, the low alloy and carbon steels are exposed to borated water. Similarly, for the MNSA repair, the crevice regions will fill with borated water if through-wall cracks are present or develop in the nozzles.

Significant corrosion data are available regarding accelerated corrosion of carbon and low alloy steel materials that may occur if they are exposed to concentrated solutions of boric acid (References 5 and 6). There is no mechanism by which boric acid can concentrate in the crevice regions to the levels described in these references. However, some corrosion will occur at the boric acid concentrations typical of normal operating and shut down conditions. The corrosion rates are low for these conditions, but there has been some concern about the amount of corrosion that could occur over an extended period of time and its effect on nozzle repair lifetime.

A second concern involves the stress corrosion cracks that remain in the Alloy 600 nozzles after the repairs. The remnants of the Alloy 600 nozzles will likely contain the original cracks that required nozzle repair since PWSCC occurs near the partial penetration welds. The residual stresses from the original welding remain in the Alloy 600 nozzles. These stresses are the major driving force for crack initiation and propagation in Alloy 600 nozzles (Reference 7). Since the stresses remain, they could continue to propagate existing cracks or initiate and propagate new cracks. These cracks could grow by the SCC mechanism through the nozzle and weld materials to the carbon or low alloy steels. The low oxygen reducing conditions in PWRs will not result in rapid stress corrosion crack propagation in the carbon and low alloy steels. However, there may be some level of concern about the extent of SCC propagation over the remaining lifetimes of various plants.

In addition, cracks in the Alloy 600 weld metal that [

]a,c

The CEOG sponsored a task to address the concerns cited above. The specific scope of work included evaluations of:

1. The carbon and low alloy steel corrosion that could occur if a half-nozzle or MNSA repair is used on a leaking nozzle. This evaluation included reviewing available laboratory and field data on the corrosion of carbon and low alloy steels to develop an expected corrosion rate, determining the maximum allowable corrosion (in accordance with ASME Boiler and Pressure Vessel rules) for bounding case nozzle configurations, and estimating the predicted time to reach the degradation limit for those bounding nozzle configurations. This subtask built upon similar work previously performed for individual CEOG members that performed nozzle replacement or repair evaluations.

2. The potential for stress corrosion cracking or fatigue crack growth in carbon and low alloy steel components. This evaluation included a review of available data on the stress corrosion cracking of carbon and low alloy steels in PWR primary side environments to demonstrate that such SCC is unlikely. The principal source for this [ ]^{a,c} In addition, [ ]^{a,c} for bounding nozzle configurations.

Results of these evaluations are presented in subsequent sections of this report.

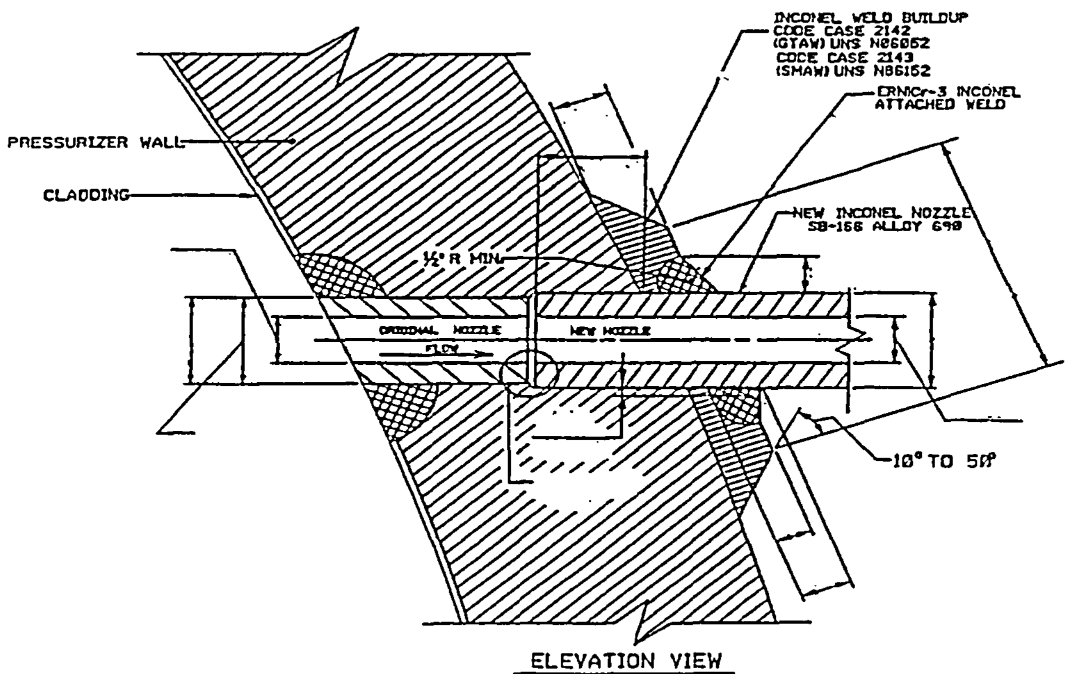

Figure 1-1 Schematic Diagram of a Half-Nozzle Repair

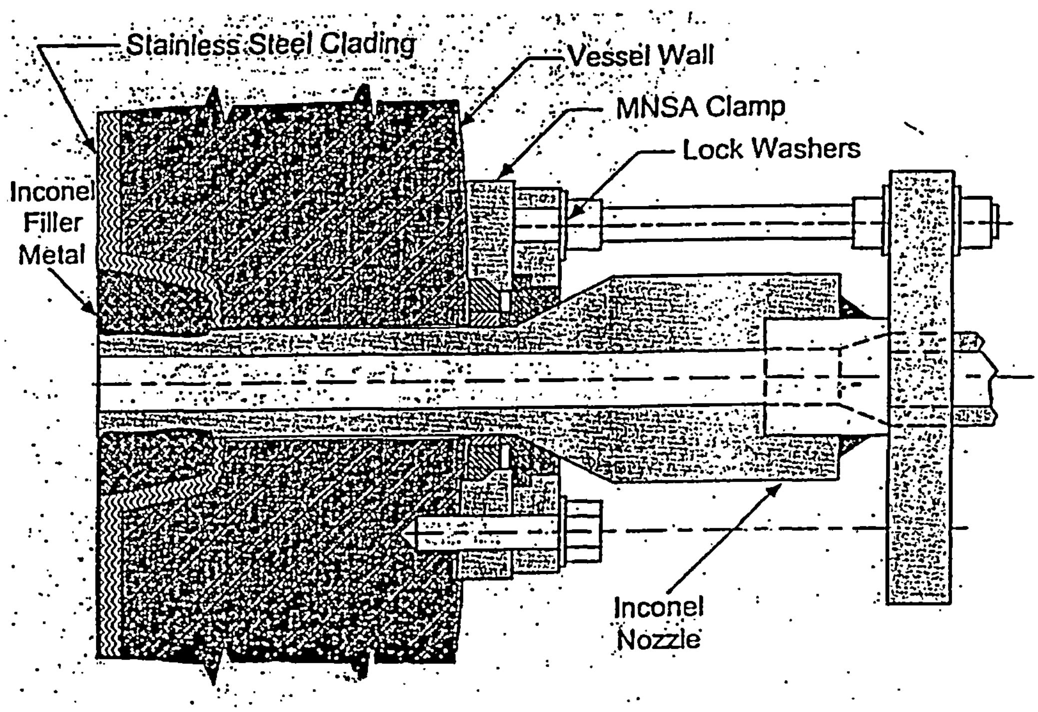

Figure 1-2 Diagram of a Mechanical Nozzle Seal Assembly (MNSA).

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2 CARBON AND LOW-ALLOY STEEL BORATED WATER CORROSION

2.1 GENERAL

The crevices between the nozzles and the pressurizer or pipe material will fill with borated water if a half-nozzle replacement/repair is implemented. Similarly, the crevice will fill with water if a MNSA repair is implemented and the nozzle has or develops a through-wall crack. Materials used for primary system components include SA 516 grade 70 carbon steel (pipe material) and SA 533 Grade B (and similar grades) low alloy steel (pressurizer shell material). When used as primary pressure boundary materials, carbon and low alloy steels are clad with corrosion resistant materials (generally weld-deposited stainless steels) to isolate these materials from the primary coolant, thereby minimizing corrosion and corrosion product release to the coolant. The inside diameters of holes, such as those used for RTD and sampling line nozzles, are not clad because, in the as-built condition, they are not exposed to borated water.

Under conditions where boric acid can concentrate, significant corrosion of carbon and low alloy steels can occur. Some corrosion will occur even at normal operating boron levels (typically, less than 1000 ppm). The expected lifetime of the half-nozzle repairs could be affected if sufficient corrosion of the steels in the crevice were to occur. This subtask [

]^{a,c} before ASME code requirements would be violated.

2.2 LABORATORY CORROSION DATA

The crevice between the nozzles and the component will fill with primary coolant. Because of the original ID weld and the OD weld associated with a half-nozzle replacement/repair, or the OD mechanical seal of the MNSA, the crevice solution cannot escape or be replenished (i.e., there is no concentration mechanism, and the level of boric acid will not exceed that of the bulk primary coolant). Therefore, the carbon or low alloy steel will be exposed to a stagnant solution of borated water.

A computerized literature search was conducted for references containing corrosion data for carbon and low alloy steels exposed to borated water. The data bases searched included: Ei Compendex (The Engineering Index which covers engineering and technology journals, transactions, reports, and special publications of the engineering societies, government agencies, conferences, etc.); METADEX (the on-line equivalent of Metals Abstracts and several similar publications which provides coverage of all aspects of metals science and metallurgy); Energy Science and Technology (covers publications related to all aspects of energy and related topics); and NTIS - National Technical Information Service (unclassified U.S. government sponsored research). The literature review provided numerous references on the boric acid corrosion of carbon and low alloy steels. However, most of these were for fasteners or for pressure vessel steels exposed to steam or borated water-steam mixtures from leaking flanges or cracked nozzles under conditions promoting the development of concentrated solutions, slurries, or wetted deposits of boric acid (References 6 and 8). Under these conditions, corrosion rates of greater than one inch per year were attained in laboratory testing.

Under conditions where boric acid can concentrate in aerated conditions, significant corrosion of carbon and low alloy steels can occur. A recent event at Davis-Besse (Reference 30) demonstrated this fact.

Severe degradation of the reactor vessel head outside surface was discovered during inspection activities. A cavity approximately 6.5 inches long, 4 to 5 inches wide and extending downward to the stainless steel cladding at the head inside surface was located next to a leaking Alloy 600 CRDM nozzle. Various reviews and analyses indicated that the nozzle probably began leaking in the 1994-96 time-frame with the leakage persisting at up to 0.2 gallon per minute until the degradation was discovered in early 2002. The corrosion rate was estimated to have progressed at up to 2 inches per year. The environment that supported the high corrosion rate was concentrated solutions or wet deposits of boric acid and leakage at a rate to cause local cooling of the reactor vessel head. After the corrosion degradation was discovered, approximately 900 lbs (11.5 cubic feet) of boric acid was removed from the reactor vessel head and an additional 10 cubic feet was removed from the containment air coolers. The degradation was attributed to boric acid corrosion by Reference 30.

An earlier event of reactor vessel head degradation caused by boric acid corrosion occurred at Turkey Point 4 as a result of leakage of up to 0.45 gpm that persisted for several months. The continued wetting of the boric acid deposits resulted in minor corrosion (approximately 0.25-inch depth) of the reactor vessel head and in the deposition of over 500 pounds of boric acid on the head. Other occurrences of low alloy steel fastener degradation in valve, pump and flange fasteners as the result of exposure to wet deposits and concentrated solutions of boric acid are reported in Reference 10.

Concern for pressure boundary leakage caused by fastener degradation events and leakage through cracks in small diameter Alloy 600 nozzles have resulted in several investigations of boric acid corrosion. These studies confirmed that concentrated solutions of boric acid caused accelerated corrosion of carbon and low alloy steels. Corrosion rates exceeding one inch per year occurred in the tests described in Reference 6 in which heated fasteners were exposed to steam from a test loop containing borated water. In the Reference 5 tests, corrosion rates of up to two inches per year were obtained in SA 533 Grade B steel mockups that contained cracked nozzles. These results were consistent with numerous field observations in which significant corrosion occurred under conditions in which concentrations of boric acid occurred in environments containing oxygen.

In a half-nozzle replacement or repair, there is no mechanism for concentrating boric acid in the crevice region and free oxygen does not exist, thus corrosion rates for carbon and low alloy steels will be low. Davis-Besse and similar events involving RCS components and fasteners are not applicable because of the dissimilarity in the environmental conditions of the two cases.

[

][a,c] In 1965, an inspection at Yankee Rowe discovered two small areas where the reactor vessel cladding had been breached. The defects were mechanical damage (fretting wear) caused by a surveillance capsule that came loose and released its mechanical test specimens and other debris into the reactor vessel lower head. These loose parts wore two areas (each about two inches square) through the type 304 stainless steel cladding, exposing the underlying base metal to the primary coolant. The cladding was in the form of eight foot by four foot stainless steel plates that were affixed to the vessel by intermittent spot welding. The spot welding left large areas where the cladding was not bonded to the low alloy steel vessel. A through-cladding defect allowed reactor coolant to enter the crevice between the cladding and the vessel, resulting in a significant area of low alloy steel being exposed to reactor coolant.

A test program evaluated the corrosion behavior of A302B low alloy steel under PWR shutdown and operating conditions, and assessed the potential for hydrogen embrittlement as a result of corrosion hydrogen absorption (a by-product of the corrosion process). A302B low alloy steel was used for several early reactor vessels, including Yankee Rowe. In this test program, specimens of A302B steel were exposed to aerated and deaerated solutions of boric acid (2000-2500 ppm boron) at temperatures between 70 and 500°F. The test included both electrically insulated specimens and specimens electrically grounded to Type 304 stainless steel to assess galvanic effects. The bulk of the testing was at low temperature (70 to 140°F) in aerated and deaerated solutions (2500 ppm boron). For these conditions, the test program characterized corrosion of A302B, permitting determination of steady-state corrosion rates. The program also included short-term tests (6-14 days) at 300-500°F in deaerated 2000 ppm boron solutions. These tests were not of sufficient duration to characterize the long-term corrosion rates at startup and operating conditions. Table 2-1 summarizes the data from this laboratory program.

The results indicated that at 100°F in aerated solutions, the average steady-state corrosion rate was 7.0 mpy (mils (0.001 in) per year) with a worst-case rate of 7.9 mpy. This temperature was selected as most representative of PWR shutdown conditions.

At 500°F in deaerated conditions, the maximum corrosion rate was 1.0 mpy based on a 7-day test. The average rate for six (6) specimens was 0.6 mpy. The test time was not sufficient for corrosion to reach a steady state condition. The rates for such a short term test would be expected to be higher than long term rates since corrosion in carbon and low alloy steels follows a logarithmic or parabolic rate law. Using such a relationship, Reference 9 estimated the steady-state high temperature corrosion rate to be about 0.24 mpy, which was deemed negligible as far as vessel integrity was concerned. The data also indicated that very little pitting occurred (uniform corrosion was observed, thus the test results would be indicative of the true penetration of the steel) and that there was no significant galvanic or crevice corrosion.

Reference 10 summarized additional test data from a program in which carbon steel specimens were tested in a deaerated 1000 ppm boron solution at 392°F (significantly below primary system operating temperature). The data indicated a corrosion rate of 0.3 mpy. At 590°F, in a 3000 ppm boron solution, the carbon steel exhibited a corrosion rate of 0.2 mpy, which is consistent with Reference 9 for the steady state corrosion rate.

Table 2-2 presents [

]^{a,b,c}

There was little variation in the corrosion rates for the individual specimens of the two grades of steel. These results are consistent with [ ]^{a,c} since these data include the initial transient corrosion rates, which are higher than the steady-state rates.

The above data were used to estimate carbon and low alloy steel corrosion at operating and shutdown conditions. At intermediate temperatures during return to power operations, the steel in the crevice region will be exposed for short times to a borated solution containing dissolved oxygen. Higher corrosion rates are expected for this phase of plant operations. [

]^{a,b,c} to evaluate corrosion under these conditions. Specimens of SA 533B and SA 508 Class 2 low alloy steels, as well as specimens containing manual welds, were tested in an autoclave environment.

Crevice and galvanic conditions were simulated in some specimens. The test environment was [

]^{a,b,c} Visually, the corrosion was uniform and there was no preferential attack of specimens with crevices or any indications of galvanic attack.

2.3 CORROSION RATE EVALUATION

The first approach to evaluate the carbon steel corrosion in the half-nozzle crevice used the data described above to develop a corrosion rate, which could be used to estimate corrosion for the remaining plant lifetimes. The following assumptions were used in developing an overall corrosion rate for carbon and low alloy steels in a crevice environment and an estimate of the total corrosion for the remaining plant lifetimes:

(1) The corrosion rate for [ ]^{a,c} The pressure boundary materials in CEOG plants are typically these grades [ ]^{a,c} There are minor compositional differences between the various grades as shown below.

COMPOSITION, Weight Percent

Element	SA 516 Grade 70	A 302B	SA 533B	SA508-2
C, max	0.27	0.25	0.25	0.27
Mn	0.79-1.30	1.07-1.62	1.10-1.55	0.50-0.90
P, max	0.035	0.035	0.035	0.25
S, max.	0.040	0.040	0.040	0.0.25
Si	0.13-0.45	0.13-0.45	0.13-0.32	0.15-0.35
Cr	NR	NR	NR	0.25-0.45
Ni	NR	NR	0.37-0.73	0.50-1.00
Mo	NR	0.41-0.64	0.41-0.64	0.55-0.70
Fe	Balance	Balance	Balance	Balance

NR = No Requirement

The differences in Mo, Mn and C contents will not affect corrosion characteristics, as these elements are not associated with corrosion resistance or lack thereof. Thus, there should not be a significant difference in corrosion rates between the various materials.

(2) [ ][a,c] This is discussed further in Section 2.4.

(3) When operating, [ ][a,c]

(4) When shut down, [ ][a,c]

(5) CE plants will [ ][a,c]

2.3.1 CORROSION RATE EVALUATION

CE plants operate at hot leg coolant temperatures of approximately 585°F to 613°F; this is not expected to change significantly in the future. All pressurizers, except for Palisades and Fort Calhoun, operate at 653°F. The temperature in the Palisades and Fort Calhoun pressurizers is approximately 643°F. The maximum test temperature in Reference 9 was 500°F. However, that test program did include tests at 300°F and 400°F in deaerated borated water, which indicated decreasing corrosion rates with increasing temperature. The decreasing corrosion is a result of the characteristics of boric acid, which at reactor operating temperatures is predominantly associated and, as such, the pH of boric acid solutions is about the same as pure water. Thus, corrosion will be approximately the same as in neutral pH high temperature water. As temperature is reduced, dissociation increases, pH is depressed and the corrosion rate increases. The Reference 10 data also support this as the data show a lower corrosion rate at the higher temperature. Based on this information, the corrosion rates at operating temperatures should not be significantly different than the reported results for 500°F.

Reference 9 reported data for A302B specimens tested for one week at 500°F in a refreshed autoclave in a 2000-ppm (parts per million) boron solution. For these specimens, the average and maximum corrosion rates were 0.6 and 1.0 mpy, respectively. As indicated above, these rates are conservative because corrosion in carbon and low alloy steels follows a logarithmic or parabolic rate law with several weeks usually required before a steady state corrosion rate is attained. Thus, the actual maximum rate will be significantly lower than 1.0 mpy. Reference 9 made an extrapolation of the data to reactor conditions and estimated the corrosion rate to be 0.24 mpy. This value is supported by data from the tests at [ ][a,b,c] For this evaluation, a corrosion rate at operating conditions (hot leg and pressurizer conditions) [ ][a,c]

2.3.2 INTERMEDIATE TEMPERATURE CORROSION RATE

The crevice region may be filled with aerated water when a plant returns to operation from a shutdown condition. The oxygen in that water will be consumed by corrosion of the steel and, to a lesser extent, of the Alloy 600 and 690 nozzle material, eventually establishing a low oxygen condition. The corrosion rate will be higher for the relatively short time when the temperature is at moderate levels. [

]^{a,c} This value is conservative because the specimens were tested in a large autoclave and the amount of oxygen available for low alloy steel corrosion was greater than would have been the case for the half-nozzle or MNSA repair crevice geometry. For this evaluation, [ ]^{a,c}

2.3.3 LOW TEMPERATURE CORROSION RATE

The primary coolant will become an aerated solution of boric acid during refueling outages and other outages. Reference 9 data indicated average and maximum corrosion rates of 7.0 and 7.9 mpy for 100°F, 2500-ppm boron solutions in tests that lasted for 121 days. The test duration was sufficiently long for a steady-state corrosion rate to be established. For this evaluation, a [
]^{a,c} the corrosion that will occur during plant shutdowns.

2.3.4 OVERALL CORROSION RATE

An overall corrosion rate for CE plants, based on [

]^{a,c} was determined as follows:

$$\left[\qquad \qquad \qquad \qquad \right]^{a,c} \qquad (1)$$

Examination of the individual terms indicates that most of the calculated corrosion will occur during [
]^{a,c}

2.4 ESTIMATE OF REPAIR LIFETIME

Reference 12 is a calculation to determine how much corrosion of nozzle/heater sleeve bores is acceptable (that is, how much larger can the bore hole become before ASME Boiler and Pressure Vessel Code requirements are exceeded). The calculation evaluated the corrosion associated with a potential repair, but is not a full and complete ASME Code evaluation of the acceptability of the repair method.

The methodology of the calculation has been previously used to evaluate nozzle repairs at several CE plants. The approach was to determine the maximum allowable hole size relative to: (1) the reduction in the effective weld shear area, and (2) the required area of reinforcement for the holes.

As the diameter of a nozzle or sleeve hole increases as a result of corrosion, the area of effective weld decreases while the applied pressure blow-off load increases. The first calculation determined the maximum hole diameter at which the strength of the weld area (new OD weld) is able to resist the pressure blow-off loads. The evaluation was based on a weld geometry similar to that shown in Figure 1 for all small nozzle bores in the CE plants. The J-weld of the nozzle repair must be able to withstand the internal pressure on the diameter of the corroded hole. The strength of the weld was determined by calculating the allowable shear stress of the weld in accordance with paragraph NB-3227.2 (a) of the ASME Code (Reference 13). The allowable diameter of a corroded hole, based on the weld shear strength, was calculated by requiring that the shear stress in the weld resulting from pressure be equal to the allowable shear stress. A pressure of [ ]^{a,c} was used for this calculation. The calculation indicated that the [ ]^{a,c} before reaching the ASME Code allowable shear stress in the J-weld. The results are applicable to all of the small diameter Alloy 600 nozzles and heater sleeves in the pressurizer, hot and cold-leg piping, and steam generator primary head in all CE plants.

The second issue addressed was the required area of reinforcement for a hole. The ASME Code requirements for reinforcement were used to determine the maximum allowable hole size for each type small diameter Alloy 600 penetration in each of the CE plants. The applications analyzed include the pressurizer upper head nozzles, the pressurizer side (lower shell) nozzles, the pressurizer lower head nozzles, the pressurizer heater sleeves, hot leg and cold leg piping nozzles, and steam generator primary head nozzles. [ ]^{a,c} provides the allowable (meets reinforcement requirements) diameters for each nozzle type for the CEOG plants. There is a significant variation in the allowable diameters based on reinforcement requirements with the smallest diameters being the cold leg piping and pressurizer side shell nozzles at Palisades. It should be emphasized that a substantial margin of safety is included in the reinforcement criterion, and a failure of the repair weld will not occur upon reaching this limit. Nevertheless, this limit was used as the basis for estimating the lifetime of the nozzle repair. With respect to the specific Palisades nozzles described, [

]^{a,c}

[ ]^{a,c} plant with the limiting diameter being the smaller of the diameters as calculated by the above methods. Cold leg nozzles are not considered the most limiting nozzles with respect to PWSCC initiation based on field experience to date and laboratory test results. Temperature is a significant environmental factor influencing PWSCC initiation and growth based on laboratory data and field experience (Reference 14). Laboratory testing has indicated that PWSCC initiation and growth varies like a standard thermally activated process, i.e., in accordance with $e^{-Q/RT}$ where Q is the activation energy of 40 to 50 kcal/mole, R is the universal gas constant (1.985×10^{-3} kcal/°K-mole) and T is the temperature in degrees Kelvin. This relationship can be used to estimate the effect of temperature differences on PWSCC initiation if all other variables are essentially unchanged. The relationship can also be used to estimate the differences in initiation time between hot and cold leg pipe locations. For example, for ANO-2 which has hot and cold leg temperatures of 600 and 544°F, respectively, this relationship predicts [ ]^{a,c} assuming all other conditions are the same. Alloy 600 nozzle field experience also supports the temperature dependency. The first leaking nozzles occurred in pressurizer locations where temperatures are significantly higher than other RCS locations. Later, some hot leg nozzles developed cracks, but to date no cold leg nozzles have developed

cracks even though material properties, product form, and fabrication techniques are nominally the same. For this reason, [

]a,c

The allowable carbon or low alloy steel corrosion for each nozzle type at each CEOG plant can be calculated [ ]a,c Table 2 provides the limiting allowable diameter for each nozzle type on a plant-by-plant basis. The limiting allowable diameter was the smaller of the diameters calculated as described above. Table 1 includes the bore diameter for each type nozzle, also on a plant-by-plant basis. The allowable increase in the diameter (because of corrosion) of the nozzle bores [

]a,c

The most limiting hot leg pipe nozzles [ ]a,c where the allowable increase in diameter was calculated as

[ ]a,c (2)

Hot leg nozzles at other CE plants [ ]a,c

The most limiting pressurizer nozzles [
]a,c

[ ]a,c the allowable increase in diameter was

[ ]a,c (3)

The remaining side shell nozzles had allowable increases in [ ]a,c except for [ ]a,c The pressurizer upper head nozzles, by comparison, [ ]a,c The bottom head nozzles had allowable increases in diameters of [ ]a,c The heater sleeves had allowable increases in [ ]a,c

Section 2.3 estimated that corrosion will [ ]a,c Since the entire hole ID surface will corrode uniformly, [
]a,c because of corrosion. Dividing the allowable increases in diameter by the estimated corrosion rate (rate at which the diameter will increase) provides an estimate of the repair lifetime considering general corrosion of the carbon or low alloy steel. For the [
]a,c can be estimated as:

[ ]a,c (4)

The most limiting pressurizer nozzles were [ ]^{a,c} whose estimated repair lifetime was calculated as:

$$[\qquad\qquad\qquad\qquad]^{a,c} \tag{5}$$

All other pressurizer nozzles and heater sleeves at all CE plants had estimated repair lifetimes [ ]^{a,c}

The most limiting pressurizer heater sleeves, which were at several CE plants, had allowable [ ]^{a,c} that resulted in an estimated lifetime of:

$$[\qquad\qquad\qquad\qquad]^{a,c} \tag{6}$$

2.5 ALTERNATE ESTIMATE OF CARBON AND LOW ALLOY STEEL CORROSION

The corrosion rate previously described is applicable to the carbon and low alloy steels exposed to bulk solutions of boric acid and not to solutions confined in a crevice where the volume of the solution is such that the solution cannot be replenished (or refreshed). When corrosion occurs, the crevice region will fill with corrosion products such as Fe_2O_3, Fe_3O_4, FeOOH, or iron borates depending on solution conditions (temperature, oxygen level, etc.). The corrosion products occupy a greater volume than the non-corroded base metal from which they originated. The ratio of corrosion product volume to that of the non-corroded material, the Pilling-Bedworth ratio, is typically about 2. The presence of corrosion products in the crevice will prevent access of the corrodent (borated water) to the carbon and low alloy steel, reducing the corrosion rate. Oxides are typically porous, contain cracks and voids, and will normally permit some access of the coolant to the steel. However, the closed crevice geometry, with only one narrow gap for the half-nozzle repair, will confine corrosion products, preventing any loss from flaking or spalling. Similarly, stress corrosion cracks are tight and will keep corrosion products in the crevice in a MNSA repair. Further corrosion will result in the crevice corrosion products becoming denser and less permeable to the primary coolant. Eventually, the corrosion process will stifle because the steel will become isolated from the coolant.

An estimate can be made of the amount of corrosion that will occur before the crevice is packed and the process stifles. [ ]^{a,c} and the nozzle OD, the [ ]^{a,c} If the ratio of corrosion product to base metal is [ ]^{a,c} will pack the crevice with corrosion products. Since access of the coolant will be severely restricted, the corrosion rate will be reduced or eliminated. Since there is no way to remove the corrosion products from the crevices between nozzles and components, this is a reasonable estimate of the lifetime corrosion resulting from nozzle repair.

The hole diameter [ ]^{a,c} for the most limiting nozzle before the ASME Code requirement is violated, Reference 12. For this alternate evaluation, an increase in the [ ]^{a,c} is predicted. This is significantly less than the

[ ]^{a,c} indicating that corrosion of the nozzle bore will not significantly affect the service lifetime of the nozzle repairs for CE plants.

2.6 FIELD EXPERIENCE WITH HALF-NOZZLE REPAIRS

The half-nozzle repair has been used to repair leaking or cracked nozzles at several PWRs. The repair with the longest service history is at ANO-1, a Babcock & Wilcox unit that developed a leak in a pressurizer vapor space instrumentation nozzle in December 1990. The leak was repaired using a short Alloy 690 nozzle and a half-nozzle repair. The ANO-1 repair is exposed to a high temperature steam environment that contains some boron, but not the same level as a pipe nozzle, and to conditions that are more stagnant, i.e., the environment outside the nozzle is not flowing water like in a pipe. The plant qualified a UT technique to inspect the low alloy steel base metal for general corrosion, applied this technique at the 1st and 2nd refueling outages after the repair, and currently conducts an inspection on an every-other-cycle basis. After approximately 10 years of service, there has been no indication of general corrosion of the low alloy steel base metal.

In 1993, San Onofre-3 performed a similar repair on a leaking hot leg nozzle. An inspection was conducted after 5 years of service by removing the half-nozzle to address boric acid corrosion concerns. Visual observation indicated only minor pitting of the base metal. The depths of the pits were 0.005 to 0.008 inch as determined from measurements of a mold of the hole. The half-nozzle repair was reinstalled.

In 1994, Florida Power & Light also made three half-nozzle repairs to pressurizer vapor space instrumentation nozzles at St Lucie-2 (Reference 15). These continue in service after approximately 6 years without any indications of degradation of the low alloy steel pressurizer material based on UT inspections of the repairs.

Other plants have operated with carbon or low alloy steels exposed to primary coolant without any noticeable degradation. These include Yankee Rowe, as previously described, which operated from 1965 until the end of life with a cladding breach without apparent reactor vessel degradation (Reference 9). Palo Verde-1 has always operated with a small section of a pump body exposed to primary coolant. In 1994, Calvert Cliffs-1 removed a leaking heater sleeve and plugged the hole without adding a corrosion resistant sleeve to protect the pressurizer shell. As a result, the unclad pressurizer shell material is exposed to the primary coolant and has operated for over 5 years without any indication of corrosion.

In summary, there have been several applications of half-nozzle type repairs in PWR primary system components, and other occurrences of carbon and low alloy steels being exposed to the primary coolant. These have operated for years without any indications of degradation.

Table 2-1

Summary of A302B Corrosion Data

(Reference 9)

Temp, °F	# Samples	Coupled	Time, Days	Rate, mpy**
140*	4	NO	8	32.3
	4	NO	23	25.7
	2	NO	58	19.3
	2	NO	62	18.0
	2	NO	120	15.3
100*	4	NO	8	19.4
	4	NO	23	18.2
	2	NO	121	9.1
70*	4	NO	8	6.3
	4	NO	23	4.3
	2	NO	58	3.0
	2	NO	62	2.9
	2	NO	122	2.2
140*	4	YES	20	20.1
	2	YES	38	20.9
	2	YES	73	18.1
	2	YES	151	16.6
100*	4	YES	13	13.4
	2	YES	38	13.8
	2	YES	67	11.9
	2	YES	146	8.0
70*	4	YES	13	6.1
	2	YES	39	4.1
	2	YES	68	2.6
	2	YES	151	2.3
500	6	YES	7	0.6
400	6	YES	6	7.9
300	6	YES	7	11.6
	6	YES	14	2.2

* aerated conditions
** mils per year (thousandths of an inch per year)
YES - galvanically coupled to Type 304 stainless steel
NO – not galvanically coupled

Table 2-2

Corrosion Test Results

a,b,c

3 CARBON AND LOW ALLOY STEEL CRACK GROWTH EVALUATION

3.1 GENERAL

A section of Alloy 600 nozzle and the partial penetration weld between the nozzle and component will remain after a half nozzle repair/replacement is completed or a MNSA is installed. The repair process will not affect residual stresses from the original nozzle installation welding process. Reference 7 and similar studies have indicated that residual stresses are sufficient to cause SCC initiation and propagation in Alloy 600 nozzles. Cracks present in the nozzles or weld metals may continue to propagate, and new cracks may initiate and propagate through the nozzle and weld metals. The process of initiating and propagating cracks may eventually relieve the weld residual stresses, but not before the cracks have propagated through the weld metal to the carbon or low alloy steel base metal. The following section assesses the significance of welding induced residual stresses associated with small diameter partial penetration welded Alloy 600 nozzles and heater sleeves.

Operating stresses in a pipe or pressurizer may be sufficient to continue propagating cracks that have reached the carbon or low alloy steel interface by a fatigue or a stress corrosion process. As a result, this repair evaluation addressed the potential for crack growth by fatigue or stress corrosion cracking in carbon or low alloy steel components in the vicinity of small diameter Alloy 600 nozzles with through-wall cracks.

To address fatigue crack growth, calculations were performed that assumed that a crack had propagated through the nozzle, associated weld metal, and had reached the interface with the carbon or low alloy steel. The calculations were performed in accordance with [ ]a,c

For each nozzle or sleeve evaluated. a flaw shape was assumed, a fracture mechanics-based stress intensity factor (K_I) was defined, ranges of K_I (ΔK_I) were determined for all applicable plant transients, incremental crack growth was determined for each transient, and the calculated end-of-life crack size determined. In each case, the stress intensity factor (K_I) associated with the end-of-life crack size was compared with the appropriate allowable fracture toughness for the normal-upset and emergency-faulted operating conditions. Sections 3.3 through 3.5 summarize the fatigue crack growth calculations.

The potential for stress corrosion crack growth was assessed by reviewing available laboratory and field data to determine if SCC of carbon and low alloy steel at PWR primary side conditions was likely. If the data indicated this possibility, crack growth would be assessed using the calculated K_I and available stress corrosion crack data. Section 3.6 assesses the potential for stress corrosion crack growth in the carbon and low alloy steel piping and pressurizer materials.

3.2 ASSESSMENT OF THE RESIDUAL STRESS DISTRIBUTION

A review of fabrication processes and available residual stress data for nickel base alloy cladding and partial penetration weld buttering concluded that residual stresses induced by these processes do not need to be considered in the crack growth analyses since tensile residual stresses will not be present at the tip on any cracks present at the interface between the weld metals and carbon or low alloy steel interface.

The basis for this conclusion is discussed in detail in Reference 16 and its references and is summarized below.

The pressurizer bottom head has a weld overlay of NiCrFe Alloy 82 that is from 3/8 to 7/16 inch thick, depending upon pressurizer design. The weld overlay is thicker than stainless steel cladding present at other locations to permit partial penetration welding of the heater sleeves to the weld overlay. Instrument nozzles in the pressurizer and reactor coolant system piping were installed somewhat differently as weld joint preparations were machined into the base material of the components (carbon or low alloy steel). These preparations were then buttered with several layers of weld metal, typically Alloy 182 and the nozzles installed by welding to the buttering.

Solidification and shrinkage of the cladding (overlay) and buttering will develop residual stresses, the magnitude of which will be related to the yield strength of the respective weld metals. Yield strengths of the nickel base weld metals such as Alloys 82 and 182 are typically similar to those in stainless steel weld metals, such as Types 308 or 309, which are used for cladding applications. The residual stresses in weld metals tend to be highest near the surface of the last layer deposited. Several layers of weld metal were deposited to develop the required cladding (or overlay) or butter thickness. Each layer, after the initial layer of weld metal, has the effect of reducing the residual stresses in the previous layers, thereby significantly reducing the residual stresses at the cladding/butter-base metal interface. Furthermore, the highest stressed locations in the buttering for the instrument nozzles were removed by the grinding used to prepare the surface for PT and for finishing the weld preparation, resulting in even lower stresses in the buttering.

After weld overlay of the pressurizer bottom head and the buttering of the weld preparation grooves for the instrument nozzles, but prior to welding of the sleeves and instrument nozzles, the components were stress-relieved (post-weld heat treated for several hours at 1150°F). Such heat treatment will relieve 30 to 40 percent of the remaining residual stress in the nickel base and austenitic stainless steel alloys and up to 90 percent of those in the carbon/low alloy steel materials, further reducing the residual stresses.

A factor in establishing relative residual stress distributions in weld metals is the difference in thermal expansion properties of the materials. There is a large difference in the expansion coefficients of stainless steel and carbon or low alloy steels. The coefficients of Alloy 600 and its weld metals are comparable to the coefficient of carbon and low alloy steels. The difference in coefficient results in a major difference in the final residual stress distribution between stainless steel and nickel base alloy cladding. During post-weld heat treatment, the stainless cladding will yield and creep in compression because of differential thermal expansion. Upon cooling, this effect is reversed and a tensile residual stress is introduced near the clad base metal interface. During normal heatup, these stresses will decrease until approximately 400°F, at which point the cladding goes through a stress free condition; at higher temperatures, the stresses in the cladding will become compressive.

For the nickel base alloys, the similarity in the coefficients means that a similar effect will not occur. Tensile residual stresses will not be introduced into the nickel base alloys during cooldown from post-weld heat treatment and significant tensile residual stresses will not be present when the cladding is heated during plant startup. For the stainless cladding, one end of the assumed flaw will be at the triple-point between the stainless steel cladding, the buttering and the base metal. At this one point only along the assumed crack front, tensile stresses could develop during transients when temperature of the cladding drops below the stress free temperature. However, at 200°F, the tensile stress resulting from the differential thermal expansion will be relatively small and likely will not have a significant effect on crack behavior.

3.3 CALCULATION OF THE STRESS INTENSITY FACTOR, K_I

Reference 17 provides a detailed evaluation of fatigue crack growth in carbon and low alloy steel base metal in the vicinity of small diameter Alloy 600 nozzles with through-wall stress corrosion cracks. This section summarizes the methodology employed and the results obtained from this evaluation. Reference 17 provides the details, assumptions, and results of the calculations.

Small diameter Alloy 600 nozzles are installed in the hot and cold leg piping, pressurizers and steam generator primary heads. These components operate at different temperatures, and thus the Alloy 600 nozzles are exposed to different temperatures. Section 2.4 and Reference 17 noted that temperature is the most significant environmental factor affecting PWSCC. The time to crack initiation varies like a standard thermally activated process, i.e., in accordance with the Arrhenius relationship with activation energy of about 50-kcal/°K mole. Section 2.4 noted that this relationship [

]^{a,c} The pressurizer temperatures are even higher (643-653°F), which would indicate even shorter times to crack initiation, assuming all other materials and stress conditions are the same. Field experience with Alloy 600 nozzles and Alloy 600 steam generator tubes has confirmed the extensive laboratory observations of this temperature dependency. The first nozzle cracks and leaks occurred in pressurizer applications, and later some hot leg pipe nozzles experienced PWSCC, but there have not been any reported stress corrosion cracks at cold leg temperatures in CE plants. Since nozzle cracking at cold leg conditions is not likely, the nozzle applications at cold leg temperatures were not included in the Reference 17 evaluations, but they are bounded by those evaluations.

The evaluations of the nozzles were performed in accordance with the ASME Code (Reference 13), Section XI, Flaw Acceptance Criteria. Bounding nozzles, based on stress conditions, were determined for pressurizer and hot leg pipe applications. The process of identifying the bounding nozzles is described in Reference 17.

The resulting bounding flaw cases considered were:

Hot Leg Cracks:

Both axial and circumferential cracks were evaluated for the hot leg nozzles locations. For computing stresses from pressure, the hot leg can be considered a cylindrical pressure vessel. Circumferential stresses in a cylindrical vessel are about twice those in the axial direction. However, the hot legs have significant longitudinal (axial) stresses from other effects such as seismic stresses and forces associated with the differential growth between the hot leg and the cold leg. The effect of these loads on the circumferential stresses is minor and was not considered for the small nozzle locations.

Pressurizer Lower Shell Axial Crack:

The axial crack orientation is more critical than the circumferential orientation due to the larger pressure stresses acting on the crack face. In addition, the presence of a weld reinforcement pad contributes to the stresses in this region. Also, insurges, which are described in Section 3.4, only affect the lower head nozzle and heater sleeve locations and the side shell nozzle location. Given this, the circumferential flaw orientation is enveloped by the axial crack.

Pressurizer Lower Head Circumferential Crack:

The lower head location bounds the locations on the pressurizer upper head since the thermal stresses were higher in the lower head region. The higher thermal stress is due to thicker cladding on the lower head as each plant has the same base metal thickness. Also, insurges only affect the lower head nozzle and heater sleeve locations and the side shell nozzle location.

The fatigue crack growth evaluation required calculation of a fracture mechanics based stress intensity factor, K_I. The calculation of K_I values required assumption of an initial flaw shape and size. For this evaluation, the initial flaws for the pressurizer heater sleeve locations were assumed to be stress corrosion cracks that had propagated completely through the depth and width of the J-groove weld and the thickness of the nickel base alloy weld butter, and to have reached the low alloy steel base metal. For the pressurizer bottom head instrument nozzle locations, the initial flaws were assumed to extend completely through the depth and width of the J-groove welds and through the nickel alloy buttering. A similar geometry was assumed for the hot leg instrument nozzles. The cracks were assumed to have not propagated by a stress corrosion mechanism into the low alloy or carbon steel based on the results of the Section 3.6 evaluation. The assumed flaws were, therefore, approximately quarter-elliptical in shape to roughly match that of the weld prep at these locations. Further description of the flaw characterization is provided by Reference 18. The specific initial flaw size used at each location is presented in the following section.

By design, the instrumentation nozzle transmits substantially no loads to the weld. Since the initial crack was assumed to have propagated completely through the weld and weld butter, residual stresses from the weld are not applicable, as discussed above. However, loads related to pressure and temperature are present in the pressurizer. Similar load conditions are present in the hot leg piping. These loads were used to calculate stresses in the base metal for normal, emergency, upset, and faulted conditions. The stress intensity factors, K_I, were calculated for each location as described in Sections 6.1 and 6.3.2 of Reference 17.

In addition to loads related directly to the pressure and temperature, additional loads for certain pressurizer bottom head locations were considered. Each pressurizer is supported by a cylindrical low alloy steel skirt as discussed in Reference 19. The support skirt base flange is bolted to the floor. At the top of the support skirt is a forging (knuckle) which connects the skirt to the pressurizer lower head. The knuckle provides a significant local increase in the stiffness of the lower head, producing non-uniform radial displacements of the lower head for pressure loads. The knuckle acts as a radial constraint for the head. Including the skirt and knuckle in the analysis will increase the local membrane stress. The maximum stresses occur near the knuckle and are significantly lower at the more remote locations on the lower head. The effects of the support skirt and knuckle on the stress intensity factors, K_I, were included in this analysis of fatigue crack growth.

3.4 FATIGUE CRACK GROWTH

This section presents the fatigue crack growth evaluation for the limiting pressurizer and hot leg instrument nozzle locations defined above. The purpose of this analysis was to subject the postulated flaws at these locations to anticipated (Level A/B) transients for the plant evaluation period to determine the final flaw size using the guidance outlined in ASME Code Section XI, Appendix A. The final flaw size was used in subsequent flaw stability calculations.

( )a,c

These transients were evaluated [

]a,c

Pressurizer insurges were not included in the original revision fatigue crack growth calculations. Insurges occur when primary coolant flows from the reactor coolant system hot leg through the surge line and into the pressurizer. Since hot leg coolant temperatures are significantly cooler than the fluid in the pressurizer, these insurges cause thermal stresses in the lower head of the pressurizer. Insurges are inadvertent results of operator actions that are not defined in the pressurizer specifications. Since insurges are not defined design basis events, their description was based on industry data. Pressurizer outsurges also occur and may produce thermal loads in the pressurizer and, thus, were also considered in this evaluation.

The crack growth analysis was performed as follows:

( )a,c

a,c

The following tables summarize the results of the fatigue crack growth evaluations for the flaw locations discussed above. Reference 17 provides details of the fatigue crack growth evaluations. The initial crack size for each location and flaw orientation is shown, as is the final calculated crack size after the fatigue crack growth evaluation and the allowable crack size considering crack stability.

a,b,c

3.5 FINAL CRACK STABILITY COMPARISONS

In this section, crack tip stress intensities at the final flaw sizes were calculated for various conditions and examined for flaw stability. All these flaws were examined for stability at the end of cool-down, for turbine/reactor trips, and for the loss of secondary flow. The hot leg circumferential flaws were also examined for stability during OBE and SSE.

The following tables summarize the stability evaluations for the flaw locations discussed above. Also noted in each table was the RT_{NDT} for the bounding cases. The tables compare the calculated stress intensity factors at final crack size with the allowable K_I and show the margin (percent) to the allowable K_I. Of the locations evaluated, the [

]^{a,c}

a,b,c

a,c

[a,c]

3.6 STRESS CORROSION CRACKING ASSESSMENT

This task evaluated the possibility that a crack that had propagated through an Alloy 600 nozzle and weld metal would continue to propagate by a stress corrosion mechanism through the carbon or low alloy steel component. Field experience, especially for PWRs, suggested a low probability that this could occur. However, the literature does contain some laboratory test data that suggests that SCC can occur in pressure vessel type steels if the right combination of environmental, material and stress conditions are present.

The available laboratory and field data were reviewed to address this potential issue. Reference 19 presented the results of a detailed evaluation, including a review of laboratory data and field experience, of the potential for SCC in pressure vessel steels.

The review of the earlier work was supplemented by additional reviews of several more recent papers on the SCC of low alloy or carbon steel.

Stress corrosion cracking is dependent on the simultaneous presence of three elements: an aggressive environment, a susceptible material condition, and a stress (applied plus residual) in excess of some threshold value. If any element is missing, SCC will not occur. The following paragraphs address these elements relative to SCC of carbon and low alloy steels.

3.6.1 ENVIRONMENTAL FACTORS

An extensive collection of papers, some of which are summarized in Reference 19, indicates that the key environmental factor affecting SCC and crack growth rates is the oxidizing potential (primarily dissolved oxygen content) of the coolant. More recent papers also support the key role of dissolved oxygen in the SCC of low alloy and carbon steels (References 20 through 23). Dissolved oxygen significantly affects the electrochemical potential (corrosion potential) of all materials. In a typical PWR, dissolved oxygen levels in the primary coolant during normal operation are less than 10 ppb.

At coolant temperatures of about 600°F, the corrosion potential of carbon and low alloy steels in a PWR environment is on the order of – 600 mV referenced to the standard hydrogen electrode. This low value of corrosion potential is the result of the hydrogen overpressure in the PWR primary coolant system, which results in reducing conditions. Figure 3-1 indicates a decrease in corrosion potential with decreasing dissolved oxygen levels. At about 550°F, corrosion potentials are above – 200mV at 100 ppb dissolved O_2 and at 30 ppb and lower, the corrosion potential is below – 600mV. The corrosion potential is also reduced by increased temperature (Reference 24). More recent papers, References 25 and 26, confirm this temperature effect. The minor variations in corrosion potential noted for the different grades of steels are related to sulfur content.

Corrosion tests of pressure vessel steels indicate there is a critical corrosion potential of approximately - 200 mV below which stress corrosion crack initiation or growth of existing defects does not occur. Figure 3-2, for example, shows that below about – 200 mv, at 550°F (288°C), there was no indication of SCC. The Figure 3-2 data were from slow strain rate tests. In these tests, the most obvious indication of SCC is lower reductions in area of the test specimens prior to fracture. Below a potential of about – 100 to – 200 mV, there was a marked effect as indicated by significantly reduced reductions in area in the test specimens as compared to results at higher potentials (Reference 27).

Cracking tended not to occur in numerous laboratory tests where conditions simulating PWR coolant were present. Control of the environment (particularly O_2 levels) was suspect in the few tests where cracking did occur at apparent PWR conditions (Reference 20).

Most of the studies in which stress corrosion cracking of carbon and low alloy steels occurred were conducted at simulated BWR normal water chemistry conditions (200 ppb oxygen, 550°F). Reference 19 indicated that at these environmental conditions, with a sufficiently high stress (stress intensity factors, K_I, of about 20 ksi-in$^{1/2}$) and sulfur levels of 0.010% or higher, carbon and low alloy steels readily crack. Cracking is greatly reduced or eliminated at lower oxygen levels.

As noted above, there have been many studies involving numerous laboratories, many specimens, and various environmental conditions, which have addressed SCC of pressure vessel steels. These studies indicate that SCC did not occur, even over extended periods of testing, under conditions of low potential and good water purity (Reference 20).

There is one additional consideration unique to half-nozzle and MNSA type repairs. High oxygen levels may be present in the crevice between the Alloy 600 nozzles and the components during start-up from refueling and other outages when the primary system is open. However, the oxygen level will be quickly reduced by the formation of corrosion products as a result of corrosion of the steel, and to a lesser extent, the Alloy 600 and 690, and the absence of an oxygen replenishment mechanism. Thus, the low oxygen condition will be quickly re-established and the potential for SCC initiation or propagation should be eliminated. Significant propagation during these brief periods of elevated oxygen levels will not occur.

Other contaminants (copper ions, chlorides, sulfates, etc.) also increase the potential for SCC of carbon and low alloy steels. Such species are believed responsible for girth weld SCC seen on the secondary side of some steam generators (Reference 21). However, there are no copper alloys in the primary systems of CEOG plants, and chlorides and sulfates are maintained at low levels. Thus, the environmental conditions expected in PWRs indicate that SCC initiation and propagation in the carbon or low alloy steels component base metals as a result of cracked Alloy 600 nozzles left in place during nozzle repair is not a concern.

3.6.2 MATERIAL FACTORS

The previous section indicated that the normal PWR environment is not conducive to stress corrosion crack propagation in pressure vessel steels. The steels that have been tested had a range of sulfur levels, manganese sulfide inclusion shape and distribution, and microstructural conditions (References 19, 25, and 26). Under PWR conditions, crack growth did not occur. Thus, the material characteristics will not affect stress corrosion crack susceptibilities of CEOG plant components.

3.6.3 STRESS INTENSITY EFFECTS

The third element required for SCC is stress, which will be present in the components as a result of operational conditions. A stress intensity factor, K_I, could be identified for the various nozzle applications. This value could be compared to an experimentally determined value for K_{ISCC}, but there are no relevant data for K_{ISCC} for pressure vessel steels (Reference 19). The tests that have been conducted indicated that, for low potential (PWR) conditions, there was no SCC growth of existing defects even at high K_I levels.

3.6.4 FIELD EXPERIENCE

The review of service experience did not identify any incidents of defects or cracks suspected as being the result of stress corrosion cracking in PWR reactor vessels or other carbon or low alloy steel components exposed to primary coolant in an unclad condition. One event involving inspection of the Yankee Rowe reactor vessel was significant. The vessel was inspected with high-resolution ultrasonic techniques about 20 years after the cladding was damaged to look for evidence of SCC associated with the resistance spot welds used to attach the stainless steel clad to the vessel. There was no evidence of SCC noted during the inspection (Reference 19).

There have been occurrences of steam generator shell cracking, but this cracking was associated with the secondary side environment (References 19 and 21). The affected components were steam generators of a particular design fabricated from A302B steel.

Cracking was attributed to contaminants from condenser cooling water, dissolved oxygen, and copper. The presence of the latter two will result in a more oxidizing environment (higher corrosion potentials) which laboratory tests and BWR field experience indicate will cause SCC if high stresses are present (References 19 and 22). These occurrences are not relevant to PWR primary side SCC.

Recently, there have been several occurrences of the stress corrosion cracking of Alloy 600 nozzle welds and piping butt welds in which cracks have propagated to the low alloy steel interface. Reference 28 describes the cracking that occurred in the Alloy 82 weld metal and the 182 butter between the hot leg piping and reactor vessel outlet nozzle at V. C. Summer. An inside surface initiated axial crack extended through most of the weld metal and butter resulting in leakage of primary coolant. Destructive examination of the flaw confirmed the presence of stress corrosion cracking which extended to but not into the low alloy steel nozzle. A small circumferential crack extended through the weld metal to the low alloy steel nozzle and but there was not any propagation into the nozzle material.

At Oconee-1, a CRDM nozzle exhibited indications of primary coolant leakage in December 2000. The leakage was the result of stress corrosion cracks that initiated in the nickel base alloy weld metal, propagated through the weld, and extended into the Alloy 600 nozzle. Reference 29 indicated that the crack in the weld metal arrested when it reached the low alloy steel vessel head material.

In 2003, Japanese plant Tsuruga-2 discovered a leak through the weld between a pressurizer relief valve nozzle (low alloy steel) and a type 316 stainless steel safe-end. The weld metal and the buttering on the nozzle were a nickel base alloy. The crack, which destructive analysis determined to be PWSCC, extended for the complete length and most of the thickness of the weld. However, the destructive examination showed that the crack extended to the interface between the weld and low alloy steel nozzle, but did not extend into the low alloy steel.

In summary, PWR field experience is consistent with laboratory observations and confirms that SCC of carbon and low alloy steel components as a result of nozzle repairs is not likely for CE NSSS plants.

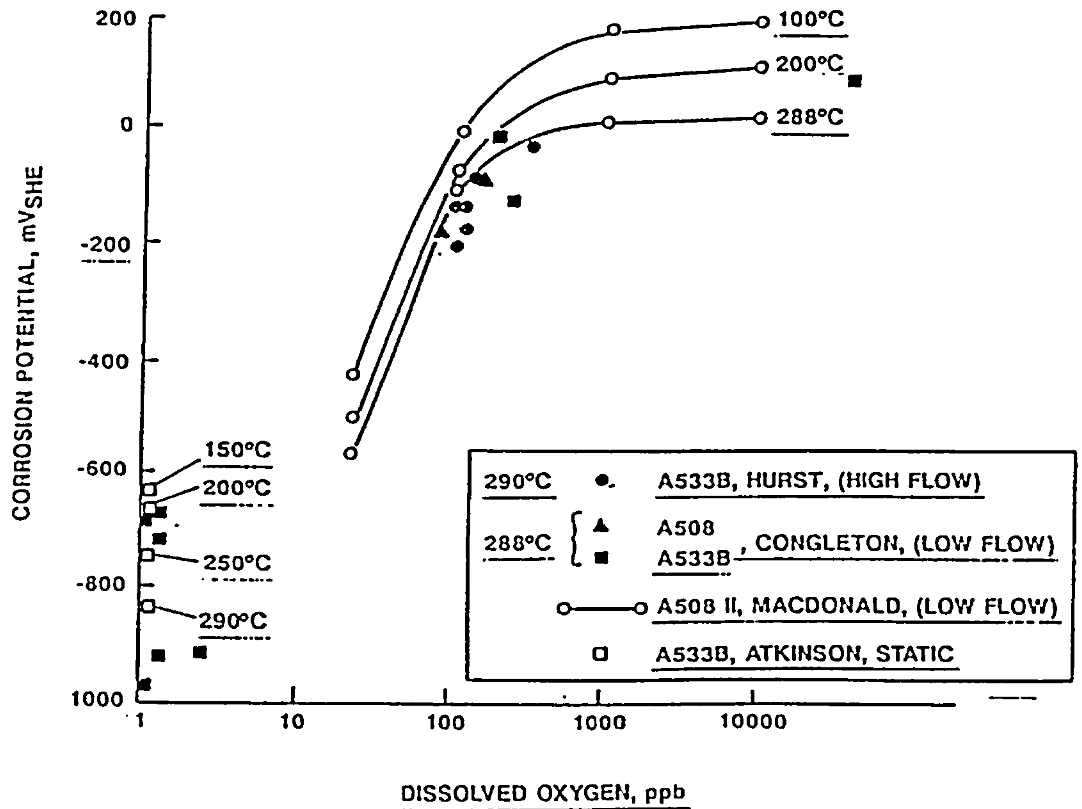

Figure 3-1 Influence of Oxygen and Temperature on Corrosion Potential of Low Alloy Steels in High Temperature Water (Reference 21)

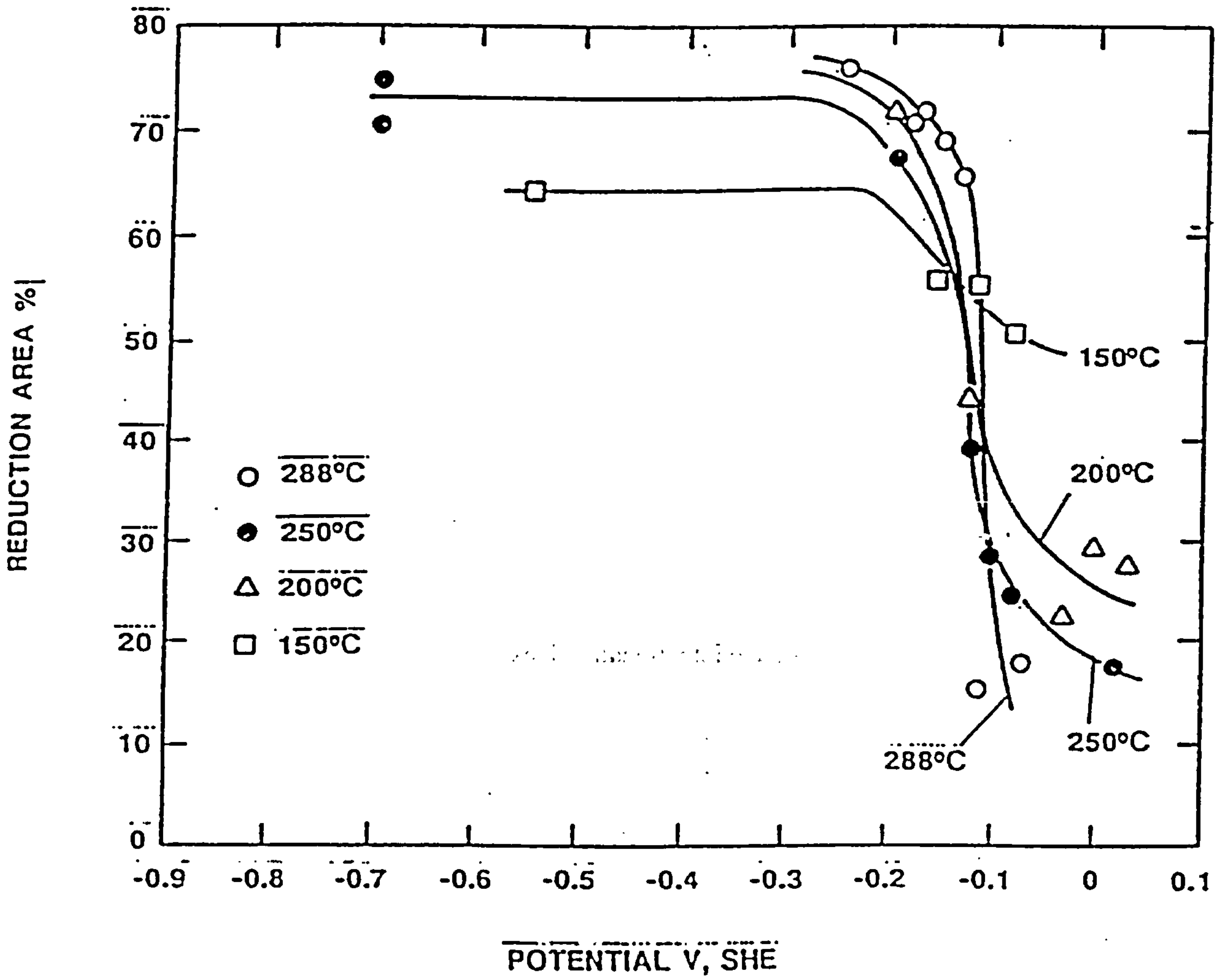

Figure 3-2 Effects of Potential upon the Reduction in Area to Fracture at Various Temperatures in Slow Strain Rate Tests (Reference 24)

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4 CONCLUSIONS/FINDINGS

This evaluation of corrosion and fatigue crack growth of carbon and low alloy steels in the crevice of Alloy 600 nozzles replaced or repaired with a half nozzle repair technique or with a MNSA resulted in the following conclusions and findings. Due to the bounding nature of this evaluation, these results are very conservative.

1. The corrosion rate of the carbon or low alloy steel in the crevice of replaced or repaired nozzles that are bounding cases for small diameter Alloy 600 nozzles in CE plants [ ]^{a,c} At this rate, the bounding case replaced or repaired hot leg nozzle for CE plants has an estimated lifetime of [ ]^{a,c} The bounding case pressurizer nozzle, with one exception, has an estimated repair life of [ ]^{a,c} The exception is [ ]^{a,c} The bounding case pressurizer heater sleeves have an estimated life of [ ]^{a,c}

2. An alternate evaluation of the corrosion occurring in the crevice considered the effects of corrosion product buildup in the crevices of the bounding case nozzles. Corrosion products will occupy a greater volume than the metals from which they originate. As a result, the crevices will eventually become packed with dense corrosion products, which will isolate the steel from the primary water environment. This will cause the corrosion process to be greatly reduced or eliminated after a period of time. [ ]^{a,c} increase in hole diameter as a result of corrosion will produce enough corrosion products to stifle the corrosion process.

3. Field experience with half-nozzle replacements or repairs and unclad surfaces in primary system applications indicates that the corrosion of the carbon and low alloy steels in nozzle crevices will not be significant.

4. Cracks that may be present in Alloy 600 remnants left in place following a half-nozzle replacement or repair, or cracks that may initiate after completion of the repair will not propagate by SCC through the carbon or low alloy steel components. The reason is the low primary side oxygen levels that result in corrosion potentials below the critical cracking potentials for these materials.

5. Fatigue crack growth in carbon and low alloy steels could occur if stress corrosion cracks propagate through the Alloy 600 remnants and associated weld metals left in place after nozzle replacement or repairs. Conservative analyses indicate that the crack depths in the [ ]^{a,c} at the end of life. The end-of-life flaw also meets the ASME criteria for emergency and faulted conditions. Similarly, the most limiting hot leg nozzle is predicted to increase to depths of no more than [ ]^{a,c} These end-of-life flaws also satisfy ASME criteria for emergency and faulted conditions.

6. All available laboratory data and field experience indicate that nozzle replacements or repairs, such as the half-nozzle replacement or repair, are viable long term options for the small diameter Alloy 600 nozzles in CE plants.

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Appendix A: Response to Request for Additional Information

Part 1 - Response to NRC Request for Additional Information concerning CE NPSD-1198-P Rev 0. Westinghouse response submitted July 2001.

Question 1-1: Section 2.3 of the report provides a corrosion rate analysis for carbon steel or low alloy steel materials. Certain assumptions and corrosion rate estimates are used in this analysis, which are based on laboratory analyses that may or may not simulate the environmental conditions for the reactor coolant under creviced conditions. There is some uncertainty as to how applicable the results of corrosion rate studies, Section 2.2 of the report, are to your corrosion rate estimates for power operations, startup/hot standby operations, and cold shutdown operations. Therefore, state whether the corrosion rates used in equation (1) on page 12 of the report include uncertainties or margins on the corrosion rates that were estimated from the results of the laboratory corrosion analyses and used to establish the overall corrosion rate. If the corrosion rate values for power operation-high temperature conditions, startup/hot standby operation-intermediate temperature conditions, and cold shutdown operation-low temperature conditions do not include additional margins in the values, provide corrected overall corrosion rates values that will account for the uncertainties in your estimates.

Response 1-1: While the laboratory tests conducted do not exactly model the nozzle and crevice configuration expected in an operating plant, the data obtained are believed applicable to the Alloy 600 crevice corrosion application. The environment that will cause general corrosion of the carbon/low-alloy steels in the crevice region will initially be aerated water with conditions equivalent to primary water. The only access to the crevice region is through stress corrosion cracks which may be present in the Alloy 600 nozzle remnants and through the small circumferential gap between the new Alloy 690 nozzle and the remnants of the original Alloy 600 nozzle. In either case, there will be little communication between the bulk primary coolant and the crevice environment. Hence, a stagnant condition will exist since there is no replenishment mechanism for the crevice environment. The chemical characteristics of the fluid trapped in the crevice will change as corrosion products build in the crevice region. The crevice pH will slowly rise as the dissolved oxygen is consumed. Accelerated corrosion of the carbon/low alloy steels can only occur if the crevice becomes significantly more acidic than the bulk environment, however, there is no mechanism by which an environment highly enriched in boric acid can develop. Thus, it is assumed that the corrosion data from the cited corrosion tests will bound carbon/low alloy steel corrosion in the crevice region.

Limited corrosion data exists for each of the conditions described. The tests did not address the effects of variations in boric acid concentration, variations in chemical compositions within a single grade of material or between grades, etc., nor did they address differences in temperatures, especially at operating conditions. The conservative approach to addressing these uncertainties was to apply additional margin to the estimated corrosion rates. Thus, at operating conditions, where Reference 9 of the report estimated a corrosion rate [ ][a,b,c] a corrosion rate [ ][a,c] was used. At intermediate temperatures, an average corrosion rate [ ][a,b,c] was indicated, but this value was conservative because the tests were conducted in a relatively large stainless steel autoclave. This results because the amount of oxygen available for corrosion in the autoclave test was greater than would be available for the crevice region of a nozzle since the ratio of carbon steel to volume of fluid was much greater and the use of a stainless steel autoclave ensured that the high oxygen condition persisted longer than would have been true if the vessel had been carbon or low alloy steel. A corrosion rate [ ]^{a,c} was used for intermediate conditions. For low temperature conditions, a corrosion rate [ ]^{a,c} as compared to an average value [ ]^{a,b,c} was used for the analysis. The overall corrosion rate, [ ]^{a,c} was judged to be sufficiently conservative to bound the uncertainties associated with the analysis.

Question 1-2: Reference 12 for the corrosion allowance evaluation and Reference 16 for the fatigue crack growth analysis have not been provided. Please provide these references for staff review. Also, the report gives two different fatigue crack growth equations for the same condition (i.e., two different fatigue crack growth equations $\Delta K > 12.04$ ksi-in$^{0.5}$). Provide corrected fatigue crack growth equations for conditions when $\Delta K > 12.04$ ksi-in$^{0.5}$, and when $\Delta K \leq 12.04$ ksi-in$^{0.5}$.

Response 1-2: Reference 12, Calculation A-CEOG-0440-1242 Rev 00, "Evaluation of the Corrosion Allowance for Reinforcement and Effective Weld to Support Small Alloy 600 Nozzle Repairs" and Reference 16, Calculation A-GEN-PS-0003, Revision 00, "Evaluation of Fatigue Crack Growth Associated with Small Diameter Nozzles in CEOG Plants" were provided for staff review. Please withhold these proprietary calculations pursuant to 10 CFR 2.790 for the reasons stated on the supplied affidavit. A correction to the fatigue crack growth (equation 7) shown in the report is provided for staff review.

Question 1-3: Pages 23-26 of the report deal with your stress corrosion cracking assessment. On page 25, you state that (1) high oxygen levels may be present in the crevice between the Alloy 600 nozzles and the carbon steel/low alloy steel components during start-ups from refueling, and other outages when the primary system is opened, and (2) the oxygen level will be quickly reduced by the formation of corrosion products as a result of steel corrosion and the absence of a oxygen replenishment mechanism. It is then concluded that the low oxygen conditions will be quickly re-established and the potential for SCC initiation should be eliminated. Analyses of residues from recently reported Alloy 600 nozzles and in-core instrumentation nozzles leaks did not demonstrate the presence of significant amounts of Fe_3O_4 (a black compound), or Fe_2O_3 (a red compound) iron oxide compounds, and therefore suggest that significant oxidation of the carbon / low- alloy steels may not be as prevalent as the report suggests. Discuss this apparent discrepancy.

Response 1-3: The perception of a discrepancy is misleading. Examination of the photographs of the Oconee-3 reactor vessel head presented at the April 2001 NRC/MRP meeting does show rust colored deposits on the downhill side of nozzle 56. The deposits around this nozzle appeared consistent with deposits around specimens in a test conducted by Westinghouse some years ago to assess low alloy steel corrosion associated with leaking small diameter Alloy 600 nozzles. However, the appearance of white deposits only on the reactor vessel head can also be explained. For example, when coolant is forced through a crack into a crevice, the coolant will flash to steam unless the crevice is sealed as a result of fabrication processes, the buildup of corrosion products, etc. A small amount of boric acid may carry over into the steam and be transported to the reactor vessel OD surface where it could deposit around the nozzles or other nearby surfaces. Other species such as lithium hydroxide, iron corrosion product, etc., would be left behind in the crevice by the flashing coolant.

Another possibility is that leakage is occurring only at operating conditions. The water/steam escaping through the crack could flush any oxygen from the crevice leaving the crevice filled with low oxygen coolant or steam. At such conditions, the oxides that form will be Fe_3O_4, which prior experience indicates is a black, tenacious oxide that would not likely be transported to the reactor head OD surface. Thus, any deposits would result from boric acid depositing adjacent to the nozzles.

In the process postulated in the report, corrosion occurs in the crevice region. Aerated water may be introduced into the crevice regions during outages when the primary system is open; this water is assumed to migrate to the crevice locations and react with the adjacent carbon / low alloy steel. Oxide formation, especially at low temperature, will quickly consume the dissolved oxygen, leading to a low oxygen condition over time. Therefore, the corrosion process postulated in WCAP-15973 (CE NPSD-1198) appears to be corroborated by the surface deposits observed at Oconee-1 & 3.

Part 2 - Response to NRC Request for Additional Information dated July 2, 2003 concerning WCAP-15973-P Rev 0. Westinghouse response submitted October 6, 2003.

Question 2-1: Section 2.6 of the topical report (TR) provides previous field experience of the half-nozzle repairs, including a pressurizer vapor space instrumentation nozzle repair performed in 1990 at Arkansas Nuclear One, Unit 1 (ANO-1). The repair was ultrasonic test (UT) inspected at the 1st and 2nd refueling outages and is currently UT inspected on an every-other-cycle basis. The repair is exposed to a high temperature steam environment which contains some boron, but not the same level as a pipe nozzle. This repair was approved provided that the licensee implements a monitoring program with a nondestructive examination technique demonstrated to be effective in evaluating base metal corrosion. A UT inspection method was developed and implemented. The monitoring plan was considered to be an essential part of the repair to provide assurance of continued safe operation, since laboratory data may not necessarily duplicate field conditions. Also, since there is limited experience with the behavior of the repair and different conditions such as potential extended outages or chemistry control fluctuations, periodic UT inspections performed every other outage of the repairs will provide the necessary data to understand the behavior of the repair and its continued safe operation. Why is a monitoring program not specified to evaluate repairs in nozzles with borated water that may be susceptible to primary water stress corrosion cracking? Please provide justification for omitting a volumetric monitoring program (such as UT inspection).

Response 2-1: There is more than limited experience with the half-nozzle replacement and similar small diameter nozzle repairs in which carbon or low alloy steels are exposed to nominal primary coolant conditions. Approximately 200 such replacements/repairs have been completed on pressurizers, hot and cold leg piping, and reactor vessels. Approximately 60 of these have been in service for 5 or more years. These nozzle locations continue to be inspected as part of existing monitoring programs. Several plants are, or will be, performing periodic volumetric inspections of nozzle repairs. In addition, as noted in the topical report, one plant removed a half-nozzle repair after 5 years of service in a hot leg location (where it was exposed to primary water, not steam) to address boric acid corrosion concerns. Only minor pitting of the carbon steel was present.

Based on the satisfactory experience with the large number of half-nozzle repairs completed to date, experience with other locations in which the cladding was removed, and the analyses performed in the topical report and similar documents, additional volumetric inspections are not required.

Question 2-2: Sections 3.1 and 3.3 of the TR specify stress intensity factor ranges of KI (?KI) and crack growth (?a). These seem to be typographical errors. Please correct these errors.

Response 2-2: This is a typographical error that sometimes occurs during printing. The intended symbol where this occurred in these sections is the delta symbol, "Δ;" this error will be corrected in the approved report.

Questions 2-3 and 2-11:

Question 2-3: Section 4.0 of CN-CI-02-71 (Summary of Fatigue Crack Growth Evaluation Associated with Small Diameter Nozzles in CEOG Plants) states that the elastic-plastic fracture mechanics (EPFM) evaluation is based on the Appendix K (ASME Section XI) approach. The Appendix K methodology is for the evaluation of flaws in reactor vessels when the vessel temperature is in the upper-shelf range. Justify the use of the Appendix K methodology in the current evaluation of crack stability for flaws originated from small diameter nozzle holes in pressurizers.

Question 2-11: Provide justification for using the J-material curve of NUREG/CR-5729 in your evaluation.

Responses 2-3 and 2-11: The Appendix K methodology was developed for application to the beltline regions of a Reactor Vessel, and in Section 4.0 of the calculation it is implied that Appendix K was used in the analysis. The elastic-plastic fracture mechanics evaluation found in Section 6.3.2.2.2 of the subject calculation was consistent with Appendix K but was tailored to the application and conditions evaluated. The methodology was actually based on Regulatory Guide (RG) 1.161, which is very similar to the non-mandatory rules given in Appendix K of Section XI of the1992 ASME Code Edition. Specific aspects of Appendix K unique to reactor vessels were therefore not applicable and were not used. For example, for reactor vessel analyses, K-1200(a) requires that flaws be postulated with the criteria of K-2000. For the Pressurizer nozzle, the postulated flaw was determined in step 14 of the procedure described in section 6.1 of the subject calculation, rather than in accordance with K-2000. Therefore, both Appendix K and RG 1.161 represent industry-accepted methodologies for evaluating crack stability, and were used as guidance for establishing the methodology used in this calculation.

Table 11 of NUREG CR5729 provides a J-R curve meeting the K-3300(b) requirements for the Pressurizer lower shell material (SA-533A or SA-533B material.) This reference provides an industry-accepted source for this data.

Questions 2-4 and 2-5:
Question 2-4: Section 6.1 of CN-CI-02-71 states that fatigue crack growth of the flaw is calculated over the remaining plant life and the final flaw size is used to confirm flaw stability at the end-of-plant life. However, plant life is not defined for these calculations. Please provide the length of time these calculations address. In addition, revise Tables 2.1, 2-3, and 2-5, by including in the tables the remaining plant life for each limiting plant selected for the fatigue crack growth calculation for the three locations. Further, report the RT_{NDT} values for the materials at the three locations being evaluated.

Question 2-5: Section 6.2.2 of CN-CI-02-71 states that the specified design operating transients pertinent to this evaluation are similar for all plants. Confirm that the occurrences of transients specified in this section are for 40 years and the fatigue crack growth calculation was based on the portion of the occurrences corresponding to the remaining plant life for specific limiting plants.

Responses 2-4 and 2-5: The plant life used in all calculations is the original design life of 40 years. The "remaining plant life" in all cases equates to 40 years because it was assumed that the flaw originates on the first day of operation. The term "remaining" was inadvertently used, as the discussion was borrowed from a similar analysis that focused on a portion of the plant life. The implied meaning of the word "remaining" therefore does not belong in this context and can be deleted everywhere it appears; it will also be deleted in the approved report. This information does not belong in Tables 2-1, 2-3 or 2-5.

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Question 2-6: Section 6.2.2.1 of CN-CI-02-71 discusses the establishment of the pressure curve based on "P_{SAT} + 200°F." Please clarify how you shift the saturation curve.

Response 2-6: The "PSAT + 200°F" expression contains a typographical error. The correct expression should read "PSAT + 200 psi." The report provides a discussion regarding the basis for developing this modification to the saturation curve.

Question 2-7: Section 6.3.1 of CN-CI-02-71 indicates that both the hand calculations and ANSYS results for stresses are presented in Appendix B, Reference 7.1.18. Provide a discussion on these two sets of results as related to the validation of your ANSYS results.

Response 2-7: Hand calculations were performed to determine pressure stresses. The ANSYS calculations were performed to calculate thermal stresses. As such, the hand calculations are not used to validate the ANSYS calculations.

Question 2-8: Section 6.3.2 of CN-CI-02-71 states that the fracture mechanics evaluation used "the guidance outlined in ASME Code Section XI Appendix A for a double-sided crack that has propagated through the J-Weld..." Provide the figure number for the crack growth rate of Appendix A and the Edition of the ASME Code that you referenced.

Response 2-8: Figure A-4300-2 of the 1992 Edition of the ASME Code Section XI was used to obtain the fatigue crack growth rate. This curve applies to carbon and low alloy ferritic steels exposed to a water environment.

Question 2-9: *Discuss the differences between the relative hole size and crack geometry of your issue and those of Raju-Newman's - address the need to use an additional margin to account for the concern for applying Raju-Newman's analytical results directly.*

Response 2-9: As stated in the subject calculation, the fracture mechanics evaluation is performed using the guidance found in ASME Code, Section XI, Appendix A (Code). This guidance outlines a process to assess a flaw left in service considering postulated operating conditions over the life of the plant. As part of this guidance, the Code offers material limits and suggested methods of analysis. In this evaluation, the Code aspects associated with material properties specified in Article A-4000 were used as directed, as was the analysis guidance specified in Article A-5000. The only modification to the Code guidance was to use a more technically appropriate formulation to calculate the Stress Intensity Factor (SIF) as is allowed by Article A-3000.

The technique used to calculate SIF in the subject calculation is based on a Newman-Raju paper "Stress Intensity Factor Equations for Cracks in Three-Dimensional Finite Bodies Subjected to Tension and Bending Loads," NASA Technical Memorandum 85793, April 1984. Specifically, this paper presents solutions for several flaw configurations including flaws adjacent to holes such as the one presented for a "Corner Elliptical Corner Crack at a Hole." Considering the actual geometry of the problem under evaluation, which is essentially a hole through a specified thickness, it was concluded that the formulation offered by this paper was more applicable to the problem than that presented in Article A-3000.

From the discussion presented in the paper, the "Corner Elliptical Corner Crack at a Hole" formulation is based on results from a three-dimensional finite element model subjected to remote tension and bending loads. It indicates an applicability range for crack depth to crack length ratios from 0.2 to 2. The paper further states that for ratios of crack depth to plate thickness less than 0.80, the equations are generally within 5% of the finite element results, except where the crack front intersects a free surface, where the equations give higher SIF than the finite element results. The paper concludes that the equations provided should be useful for correlating and predicting fatigue crack growth rate as well as in computing fracture toughness and fracture loads for these types of crack configurations.

In conclusion, based on our study of this paper, Westinghouse believes that this is an appropriate alternative to calculating the stress intensity factor for this problem than what is provided in ASME Code, Section XI, Appendix A and can be applied without adding any additional margin.

Question 2-10: The last paragraph of Section 6.3.2 of CN-CI-02-71 indicates that thermal stresses are dominant in the pressurizer lower head due to its thick cladding. Was cladding with an appropriate thermal expansion coefficient modeled in your heat transfer analysis? Discuss the appropriateness of your heat transfer analysis.

Response 2-10: The thermal analysis of the Pressurizer was performed for the effects of the modified design basis transient identified in Figure 6-3 of Section 6.2.2.1. In general, the temperature distribution through the wall was characterized by a partial differential equation defined for the applicable boundary conditions and geometry, and solved numerically using the finite element model to determine wall temperature as a function of radius, time, and thermal rate. The thermal time histories were input to the ANSYS finite element models as a series of discrete (time, temperature) points, and a time history thermal analysis was performed for each transient.

The models were sufficiently detailed to provide an accurate distribution of temperature as a function of radial location and transient time. Cladding was modeled as part of the thermal analysis. Variation of material properties is modeled, allowing for the change in material thermal properties between the cladding and the base metal. The appropriate thermal conductivities and thermal diffusivities for the base and clad materials were obtained from the ASME Code.

Part 3 - Response to NRC Request for Additional Information concerning Calculation CN-CI-02-71-P Rev 1, "Summary of Fatigue Crack Growth Evaluation Associated with Small Diameter Nozzles in CEOG Plants." Westinghouse response submitted August 11, 2004.

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WCAP-15973-NP-A, Rev. 0

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