WCAP-14447

Repair Boundary for Parent Tube Indications Within the Upper Joint Zone of Hybrid Expansion Joint (HEJ) Sleeved Tubes

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1.0 Introduction

In the Spring and Fall of 1994, and the Spring of 1995, indications were found in the hybrid expansion joint (HEJ) region of Steam Generator (SG) tubes which had been sleeved using Westinghouse HEJ sleeves. As a result of these findings, analytic and test evaluations were performed[1] to assess the effect of the degradation on the structural, and leakage, integrity of the sleeve/tube joint relative to the requirements of the United States Nuclear Regulatory Commission's (NRC) draft Regulatory Guide (RG) 1.121, Reference 10. The results of these evaluations demonstrated that tubes with implied or known crack-like circumferential parent tube indications (PTIs) located 1.1" or farther below the bottom of the hardroll upper transition, have sufficient, and significant, integrity relative to the requirements of the RG. Thus, the purpose of this report is to provide justification for a repair boundary that supersedes that specified in the original Westinghouse WCAP[2] qualification documents. A listing of United States plants with installed HEJs is provided in Table 1-1.

1.1 Description of the Sleeving Process

In accordance with Plant Technical Specification requirements, steam generator tubes are periodically inspected for degradation using nondestructive examination (NDE) techniques. If established degradation acceptance criteria are exceeded, the indication must be removed from service by plugging or repairing the tube. Tube sleeving is one repair technique used to return a tube to an operable condition.

In the sleeving technique, a smaller diameter tube, or sleeve, is positioned within the parent tube so as to span the degraded region. The ends of the sleeve are then secured to the parent tube forming a new pressure boundary and structural element between the attachment points. Sleeves may be positioned at any location along the straight length of a tube, but are typically placed to repair tube degradation at the top of, or within the tubesheet, or at tube support plate (TSP) intersections. Sleeves may be of various lengths and may be attached to the parent tube in a variety of ways. In the case of Westinghouse sleeve designs, the method of attachment is generally restricted to either a leak limiting mechanical HEJ or a hermetic Laser Welded Sleeve (LWS) joint. The type of the particular joint configuration is a function of the date of installation and/or the customer's needs and the current plant operating conditions. Figure 1-1 shows a schematic of a typical HEJ tubesheet sleeve installation. Figure 1-2 illustrates the details of the upper joint along with terminology used in this report. Typical dimensions of the joint are illustrated on Figure 1-3. Note that only the sleeve/tube upper joint is referred to as a HEJ, and the sleeve is referred to as an HEJ sleeve.

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[1] References 8 and 9, supplemented by References 11 and 12.

[2] Westinghouse Commercial Atomic Power

1.2 Summary of HEJ Sleeve Installations

As shown in Table 1-2, since its inception in 1980, the HEJ sleeve has been successfully used to restore over 28,000 steam generator tubes to operational status. Due to decommissioning of plants and replacement of steam generators, only about 12,000 HEJ sleeves remain in service. As shown in Table 1-3, HEJ sleeves are currently in service in the United States at the D. C. Cook Unit 1, Point Beach Unit 2, Kewaunee, and Zion Unit 1 nuclear power plants. The HEJ sleeves listed in Table 1-2 were installed between April 1983 and May 1993, and have operated in the United States without incidence of significant leakage through the upper joint; Doel 4 (Belgium) experienced leakage through an upper joint crack in a parent tube in April of 1994.

Until March of 1994 there had been no reports of degradation of the parent tubes or the sleeves. In 1994, degradation of the parent tube of HEJ sleeved tubes was detected at the Kewaunee, Point Beach 2, and Doel 4 power plants. At Kewaunee the indications were predominantly located in the hardroll lower transition (HRLT), while at Point Beach 2 the indications were predominately in the hydraulic expansion lower transition (HELT), and at Doel 4 the two confirmed indications were located at the hydraulic expansion upper transition (HEUT). Additional degradation was reported at Kewaunee in the Spring of 1995, and three sleeve/tube joints were removed from the "B" SG for laboratory examination. The structural and leakage integrity of HEJs in 7/8" nominal diameter tubes with indications located 1.1" below the hardroll upper transition (HRUT), and lower, is the subject of this report.

1.3 Summary of the HEJ Repair Boundary Qualified in this Report

The repair boundary is based on analytic evaluations, the results of prototypic testing, and the results of the destructive examinations and tests of the HEJ specimens removed from Kewaunee. The reference location, i.e., the bottom of the HRUT, for reckoning the repair boundary was selected based on the ease of measuring the elevation of indications relative to the that location using existing, e.g., the Westinghouse CECCO and the Zetec + Point eddy current probes, nondestructive examination (NDE) technology. The actual location of the repair boundary is supported by the structural and leakage evaluations performed using the data from the destructive examinations of the field specimens and the prototypic testing reported in WCAP-14157 and its addendum.

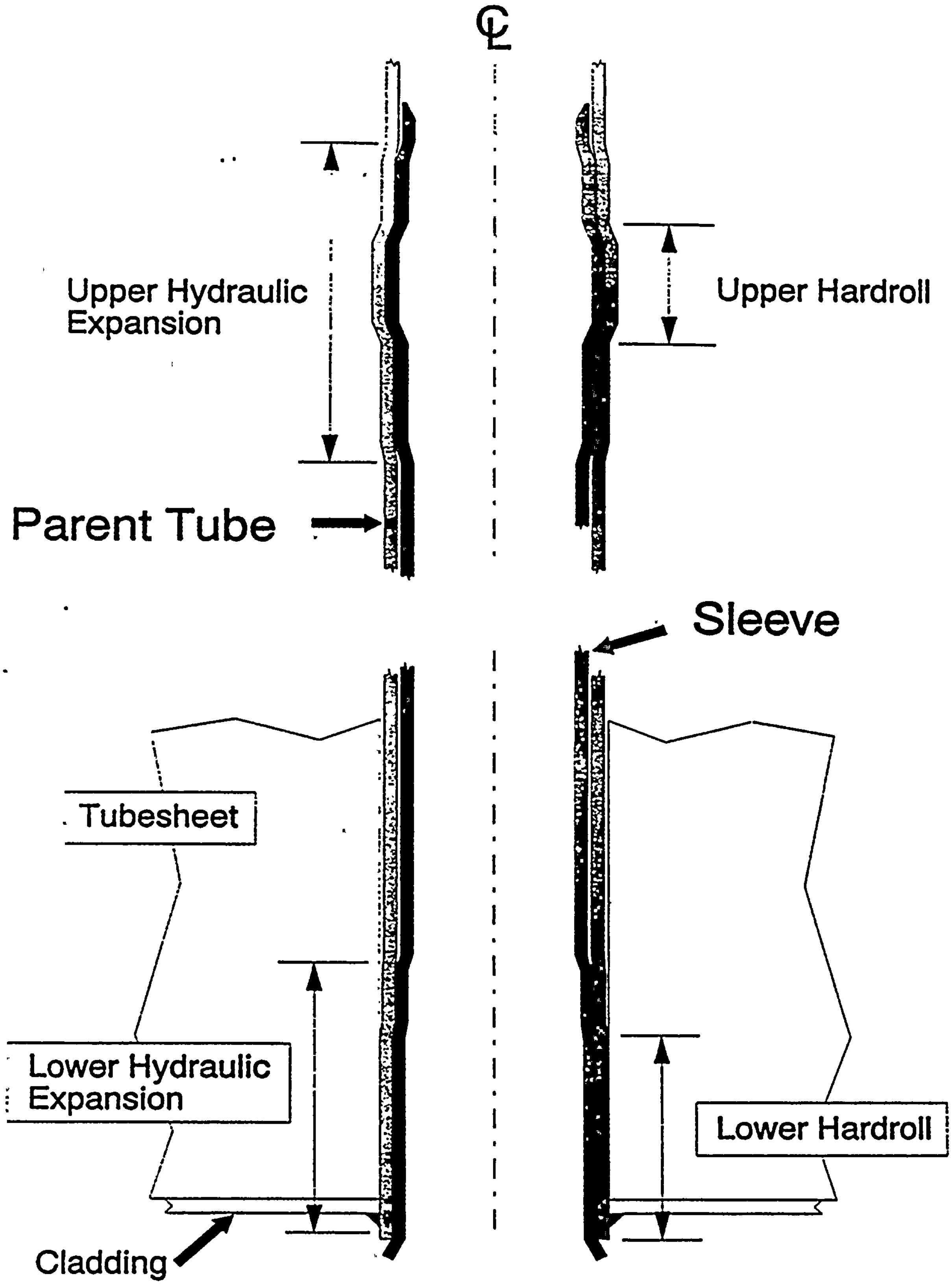
Table 1-1: Sleeving Design Documents for United States Plants with HEJs		
Design Document	Subject	Reference(s)
WCAP-9960	Point Beach Unit 2, Alloy 600 sleeves	1, 2
WCAP-11573	Point Beach Unit 2, Alloy 690 Sleeves	3
WCAP-11643	Kewaunee, Alloy 690 Sleeves	4, 5
WCAP-11669	Zion Units 1 & 2, Alloy 690 Sleeves	6
WCAP-12623	D. C. Cook Unit 1, Alloy 690 Sleeves	7

Table 1-2: Westinghouse Sleeving Experience Chronology							
Plant	Date Installed	S/G Type	Sleeve Type(1)	Number of Sleeves	Sleeve Characteristics		
					Material	Length (in)	Type
San Onofre 2	10/80-6/81	W-27	TS	6929	600TT	27,30,36	HEJ
Point Beach 1	11/81	W-44	TS	13	600TT	36	HEJ(2)
Indian Point 3	10/82-1/83	W-44	TS	2971	600TT	36,40,44	HEJ
Point Beach 2	4-6/83	W-44	TS	3000	600TT	36	HEJ
Millstone 2	7-9/83	CE-67	TS	2036	625/690TT	40	HEJ
Ringhals 2	05/84	W-51	TS	17	690TT	30	Braze
Millstone 2	03/85	CE-67	TS	2926	625/690TT	40	HEJ
Indian Point 3	07/85	W-44	TS	635	600TT	36,40,44	HEJ
Millstone 2	11/86	CE-67	TS	225	625/690TT	40	HEJ
Point Beach 2	10/87	W-44	TS	87	690TT	36	HEJ
Kewaunee	03/88	W-51	TS	1940	690TT	30,36	HEJ
Zion 1	03/88	W-51	TS	58	690TT	30	HEJ
Doel 3	06/88	W-51	TS	54	690TT	30	Laser(3)
Point Beach 2	10/88	W-44	TS	509	690TT	30	HEJ
Kewaunee	03/89	W -51	TS	1698	690TT	30,36	HEJ
Point Beach 2	10/89	W-44	TS	298	690TT	36	HEJ
Kewaunee	03/91	W-51	TS	691	690TT	27,30,36	HEJ
Farley 2	3/92	W-51	TSP	69	690TT	30	Laser(4)
Farley 2	3/92	W-51	TS	30	690TT	12	Laser(4)
D. C. Cook 1	7/92	W-51	TS	1840	690TT	30,27	HEJ
Farley 1	9/92	W-51	TSP	148	690TT	30	Laser(4)
Farley 1	9/92	W-51	TS	446	690TT	12	Laser(4)
Doel 4	5/93	W-E1	TS	1752	690TT	30,36	HEJ
Doel 4	1994	W-E1	TS	>11000	690TT	12	Laser(4)
			Total	>39000			

Notes:
(1) TS = tubesheet sleeve & TSP = tube support plate sleeve.
(2) Brazed sleeves also installed.
(3) CO_2 laser used for the welding process.
(4) YAG laser used for the welding process.

Table 1-3: HEJ Sleeves Operational Status as of 1994						
Plant	Date Installed	S/G Type	Number of Sleeves[1]	Sleeve Characteristics		
				Material	Length (in)	Type
Point Beach 2	4-6/83	W-44	3000	600TT	36	HEJ
Point Beach 2	10/87	W-44	87	690TT	36	HEJ
Kewaunee	3/88	W-51	1940	690TT	30,36	HEJ
Zion 1	3/88	W-51	47	690TT	30	HEJ
Point Beach 2	10/88	W-44	509	690TT	30	HEJ
Kewaunee	3/89	W-51	1698	690TT	30,36	HEJ
Point Beach 2	10/89	W-44	298	690TT	36	HEJ
Kewaunee	3/91	W-51	691	690TT	27,30,36	HEJ
D. C. Cook 1	7/92	W-51	1840	690TT	30,27	HEJ
Doel 4 [2]	5/93	W-E1	1752	690TT	30,36	HEJ
		Total	11862			

Notes: (1) Number is approximate.
(2) HEJ modified by YAG laser welding in 1994.



HEJ-INST.WPG

Figure 1-1: Typical HEJ Sleeve Installation

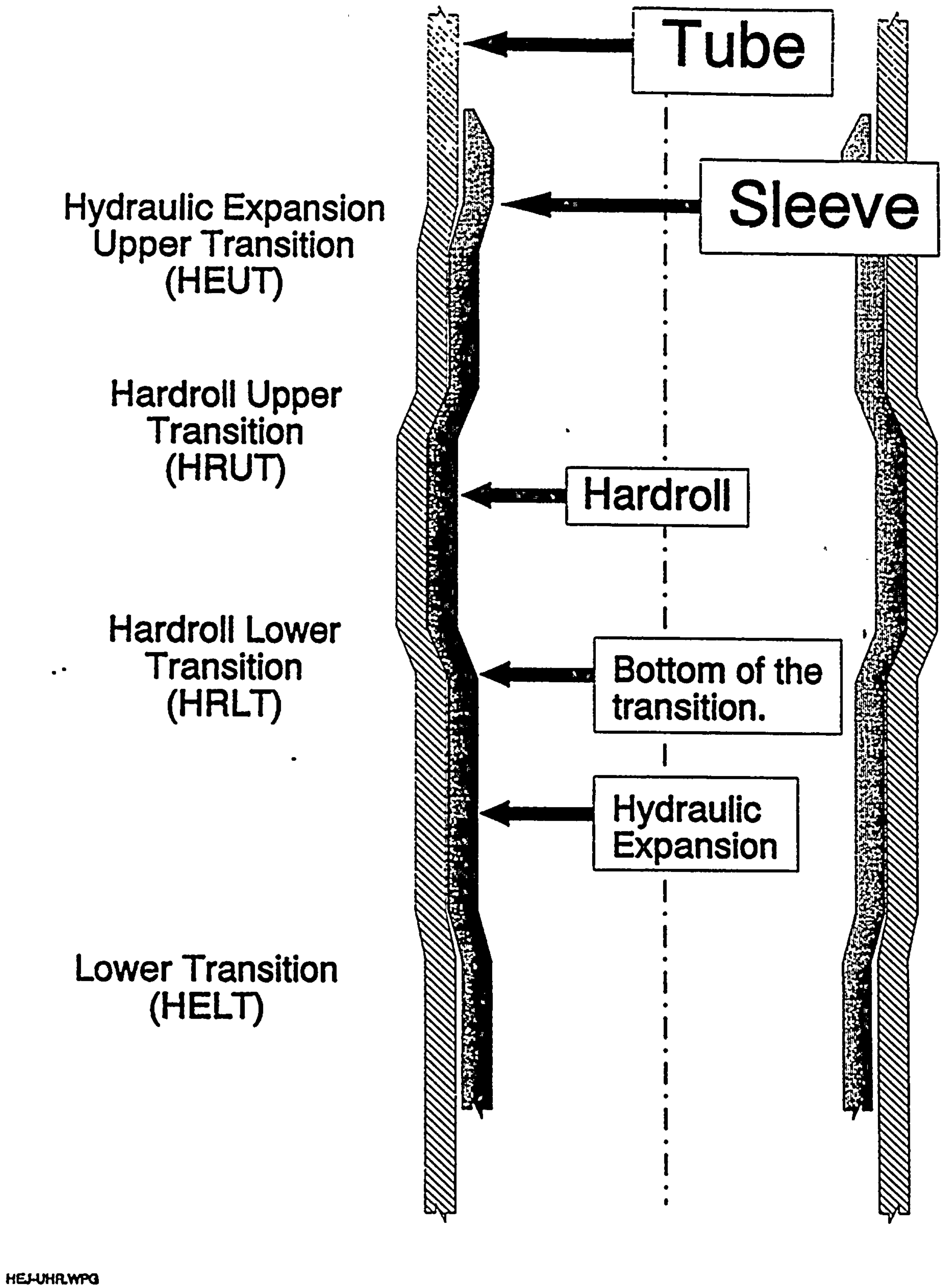


Figure 1-2: Hybrid Expansion Joint Configuration

a,c

HEJ-DIMS.WPG

Figure 1-3: Typical Dimensions of the HEJ

2.0 Discussion and Conclusions

The burst criteria of draft RG 1.121 were used to establish a repair boundary for HEJs with PTIs. The continued safe operation of the SGs is not compromised if the PTIs are located below the repair boundary, i.e., 1.1" downward from the bottom of the HRUT or lower, as illustrated on Figure 2-1.

A geometry based argument has been developed, Section 7.0, to support the repair boundary as established by structural considerations for PTIs in HEJ sleeved tubes: A summary of the conclusions relative to the establishment and implementation of the repair boundary for HEJ sleeved tubes in Westinghouse Model 44 and 51 SGs is provided in Section 2.2. Additional sections of this report provide a discussion of field experiences through the date of publication of this report, the details of the destructive examinations of sleeved tube sections removed from an operating SG, and structural integrity and potential leak rate considerations made to establish the repair boundary.

2.1 Discussion

During the Spring, 1995, outage at Kewaunee, three (3) HEJ sleeved tube sections were removed intact from SG "B" for laboratory examination. One of the sections was designated for archive retention and the remaining two sections have been destructively examined. Each of the specimens exhibited field called PTIs in the hardroll lower transition using the + Point probe. The indications were confirmed to be extensive, circumferentially oriented, stress corrosion crack arrays (SCC) originating on the inside surface of the tube, confirming the accuracy of the detection and sizing of the NDE. No cracking of the sleeves, and no cracking in the upper transitions of the tubes was found. A detailed discussion of the results of the examinations are provided in Section 5.0 of this report. Structural tests done on two[1] of the removed HEJ tube sections strongly supports the establishment of the repair boundary as stated in this report.

As reported in References 8 and 9, structural analyses and tests were performed which demonstrated that degradation of any extent below the middle of the HRLT could be tolerated without violating draft RG 1.121 requirements for protection against burst for tubes subject to degradation. References 8 and 9 also presented structural integrity and leak rate information relative to failure of the tube/sleeve joint for cracks above the middle of the hardroll if the circumferential extent did not exceed a specified limit. These latter evaluations are not directly germane to the repair boundary established herein; however, a chronological discussion of those evaluations, and activities proposing license amendments, is provided in Appendix A to this report.

[1] The third section sample is being retained as an archive specimen for future testing if necessary.

2.2 Conclusions

This document is applicable to the HEJs in service in SGs at D. C. Cook Unit 1, Kewaunee, Point Beach Unit 2, and Zion Unit 1. Specific conclusions relative to the location of the repair boundary, axially oriented PTIs, primary-to-secondary leakage, and the susceptibility of the upper transitions to concurrent degradation are provided in the following subsections.

2.2.1 Indication Locations

Tests conducted in joints designed to simulate a 360° throughwall crack have shown that the upper hardroll must have additional axial load carrying capability to supplement the radial contact pressure of the sleeve-to-tube interface. To comply with this condition, PTIs in the sleeve/tube joint, i.e., the HEJ, must be limited to 1.1" and lower as reckoned downward from the bottom of the HRUT.

It is to be noted that a significant database of field NDE information has been accumulated that demonstrates that the appearance of PTIs in the lower transitions of an HEJ does not imply a susceptibility of the tubes to upper transition PTIs. This is supported by the findings from the destructive examination of several HEJs removed from operating SGs in the United States and Europe.

2.2.2 Allowable Indication Arc Length

Testing of surrogate and field specimens has demonstrated that an HEJ with a 360° through-wall PTI indication at/below the middle of the HRLT will successfully withstand the loads resulting from three times the normal operating pressure differential and 1.43 times the postulated SLB pressure differential. Therefore, there is no BOC limitation on the circumferential extent of PTIs located below the repair boundary as describe in this report.

2.2.3 Axial Indications

Axial indications do not independently result in a significant reduction of the axial load carrying capacity of the joint. However, without additional information, it may be supposed that the presence of axial indications may degrade the axial load carrying capability if circumferential cracking is concurrently present. In addition, axial cracks could have an effect on leakage through the sleeve-to-tube joint. Until additional information is developed, it is recommended that HEJs exhibiting axial PTIs above the bottom of the HRLT be removed from service.

2.2.4 Primary-to-Secondary Leakage

The use of the specified repair boundary for PTIs should be implemented in concert with an operational leakage limit of 150 gpd and enhanced inspection criteria designed to quantify the orientation and location of potentially crack-like PTIs. Analyses have shown that the tubesheet sleeve lower hardroll joint, located at the tube entry, poses no structural or leakage

integrity concerns. The demonstration of the upper joint integrity has been demonstrated based on mechanical test programs supplemented by analytic evaluations.

Potential primary-to-secondary steam generator tube leakage should be calculated for indications remaining in-service within the identified repair boundary zone. The total predicted leakage from the SG during a postulated SLB event should be compared against the allowable leakage as determined using NUREG-0800 calculation guidelines.

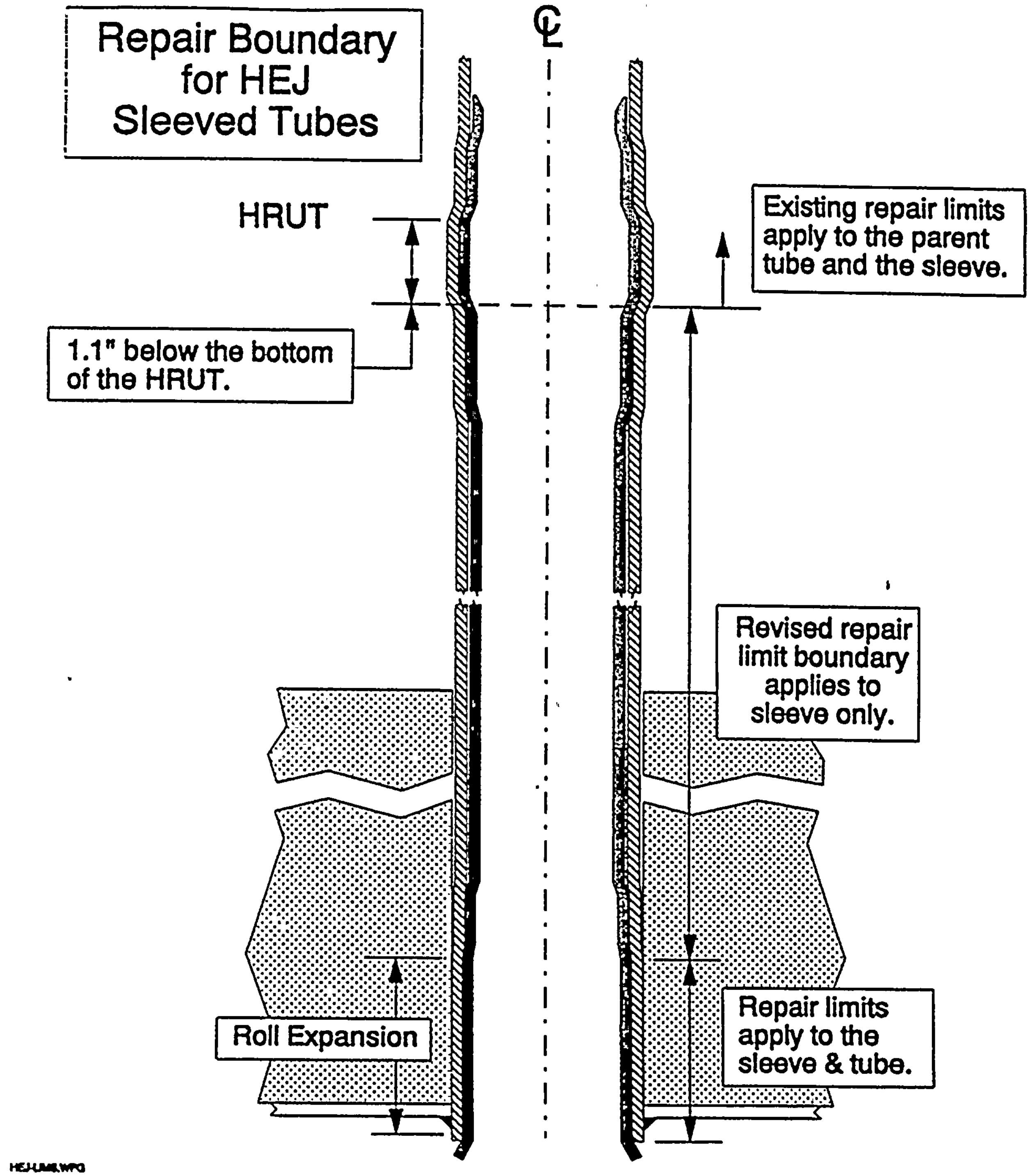


Figure 2-1: Revised Pressure Boundary Definition for HEJ Sleeved Tubes

3.0 Regulatory Requirements

In order to repair SG tubes, an integrated qualification plan was developed to demonstrate the acceptability of the HEJ sleeve/tube joint. Documentation of the sleeve design and attendant analyses of Alloy 600 and 690 thermally treated HEJ sleeves for the repair of SG tubes are contained in Westinghouse technical reports referred to as WCAPs. These reports describe the design basis for sleeving as a repair, the testing and analysis used to support the acceptability of the repair technique, and the method used to demonstrate acceptability of the repair following its application. A similar approach is taken in this report. The repair boundary for the parent tube in the HEJ HRLT is established such that the design basis of the sleeve/tube meets the requirements of RG 1.121. A listing of the WCAP reports applicable to the plants in question was provided in Section 1 of this report.

Current WCAPs define the sleeving application and repair limits. They define the zones of in-service-inspection for the sleeve, and the limit of acceptable sleeve and sleeve joint degradation. The sleeved tube inspection requirements and repair boundary for the HEJ are summarized in Figure 2-1.

Based upon the experiences at Kewaunee, Point Beach 2, and Doel 4, it is evident that the parent tube material in the vicinity of the HEJ transitions can be subject to the development of PTIs. In order to prevent the unnecessary plugging of potentially degraded sleeved tubes, the structural integrity of the degraded joints may be evaluated against the burst criteria of draft RG 1.121. In addition, the leakage integrity of the sleeved tubes with PTIs should not represent a potential for offsite doses to exceed the limits defined in Title 10 of the Code of Federal Regulations Part 100 (10 CFR 100).

RG 1.121 describes a method acceptable to the NRC staff for meeting General Design Criteria 14, 15, 31 and 32 by reducing the probability and consequences of steam generator tube rupture. This is accomplished by determining the limiting safe conditions of degradation of steam generator tubing, beyond which tubes with unacceptable cracking, as established by in-service inspection, should be removed from service or repaired. The repair boundary is established such that the primary-to-secondary pressure boundary will not result in tubes with partial and/or complete throughwall PTIs outside of the boundary being returned to service. The regulatory basis for leaving the indications within the boundary limits in service is discussed below.

3.1 Regulatory Guide 1.121

In establishing the HEJ parent tube repair boundary, the elevation of PTIs in the tube span between the tubesheet and HEJ transitions must be considered. The main purpose of a sleeve is to bridge PTIs with a new pressure boundary. The parent tube repair boundary established by References 1 through 7 documented the potential for PTIs to exist up to 1" below the hardroll. The HEJ joint inherently provides protection to tube burst and significant leakage. The NRC staff has defined tube rupture in NUREG-0844 as an uncontrollable release of reactor coolant in excess of the normal makeup capacity. Examining the upper HEJ, tube

burst would only be expected if a circumferential separation of the parent tube is postulated, and the parent tube was then pushed out of intimate contact with the sleeve due to normal operating or faulted loads. These loads are generated by the pressure differential across the tube wall, represented by the tube end cap loads. Draft RG 1.121 uses factors of safety consistent with Section III of the ASME Code. The HEJ, and areas within the HEJ where degradation has been indicated by NDE, provides an overlap of the tube and the sleeve for a length of approximately 3 inches in the free-span region above the top of the tubesheet. This overlap must be considered in the overall evaluation of the proposed degradation acceptance limits.

3.2 Accident Condition Allowable Leak Rate

The accidents that are affected by primary-to-secondary leakage are those that include, in the activity release and offsite dose calculation, modeling of leakage and secondary steam release to the environment. The postulated steam line break (SLB) accident represents the most limiting case due to the potential for increasing leakage due to the steadily increasing primary-to-secondary pressure differential during recovery from the accident and the direct release path to the environment provided by the break in the steam pipe.

Establishment of the repair boundary includes calculation of the maximum permissible steam generator primary-to-secondary leak rate during a steam line break outside of the containment building. Standard Review Plan (NUREG-0800) methodology is used to establish the maximum permissible leak rate. This methodology has been used to justify primary-to-secondary leak rates greater than the value of 1.0 gpm normally assumed in the plants' FSAR. This methodology has been utilized previously by the NRC for the licensing of the steam generator tube support plate voltage based plugging criteria, described in Generic Letter 95-05. NUREG-0800 limits the thyroid dose to 10% of the 10 CFR 100 limit of 300 Rem for the accident initiated iodine spike case. The repair boundary established in this report considers a conservative SLB per tube leakage allowance based on test data to account for potential leakage from PTIs left in service. The total SG SLB leak rate from all sources (including calculated leakage from TSP intersections which are addressed by Generic Letter 95-05) is summed when comparing the estimated leak rate against the value established using the methodology of NUREG 0800.

4.0 Field Experience

4.1 HEJ Sleeved Tube Indications

4.1.1 Kewaunee Nuclear Power Plant

In April of 1994, seventy-seven (77) PTIs were detected in the HEJ of sleeved tubes (based on a 100% inspection) in the SGs at the Kewaunee Nuclear Power Plant using the Zetec I-coil eddy current inspection probe. A detailed description of the indications and their locations is provided in Reference 8. One (1) circumferential PTI (about 34°) was found at the HEUT, see Figure 1-2 for the joint designations. There was no operating leakage attributable to the presence of this indication. One (1) indication was found to be axial and contained within the hardroll (HR) expansion. No axial indications were identified above or below the HR. Two (2) indications were identified as *volumetric* within the hydraulic expansion below the HRLT. Sixty-two (62) indications were identified as circumferential and located at the HRLT. The remaining eleven (11) indications were located at/below the bottom of the HELT. There were no instances of multiple indications in a single HEJ. The circumferential extent of the indications ranged from 45° to 285°, with nine (9) being judged to be greater than 200° in extent. The average elevation of the sixty-two indications was found to be 1.42" below the top of the HRUT with a standard deviation of 0.08". The calendar time of operation for the tubes following sleeving ranged from five to six years. The distribution of the indications as a function of installation year is provided in Table 4-1.

In April of 1995, seven-hundred and thirty-eight (738) HEJ PTIs were detected using the Zetec + Point eddy current inspection probe. Again, a 100% inspection of the HEJs in the SGs was performed. Five (5) circumferentially oriented PTIs were reported at the HE upper transition. Again, there was no leakage reported from any of the indications. Nine (9) axially oriented PTIs were reported in the hardroll region. Six-hundred and forty-three (643) circumferential PTIs were reported at elevations ranging from 1.00" to 1.75" below the bottom of the HRUT. This corresponds to 0.00" to 0.75" below the nominal top of the HRLT. The remaining eighty-one (81) indictions were located at/below the HELT. One tube was reported as having multiple, i.e., two, PTIs, both of which were below the top of the HRLT. The circumferential extent of the indications ranged from 45° to 360° based on the NDE. The average elevation of the HRLT PTIs was found to be 1.32" below the bottom of the HRUT with a standard deviation of 0.10". The sleeves had been installed in 1988, 1989, and 1991, and were fabricated from thermally treated Alloy 690 material. The distribution of the indications as a function of installation year is provided in Table 4-2.

4.1.2 Point Beach Unit 2 Nuclear Power Plant

In October of 1994, two-hundred and thirty (230) circumferentially oriented HEJ PTIs were detected using the Westinghouse/Ontario Hydro CECCO 3 eddy current inspection probe. All of the HEJs were examined on the hot leg of the SGs. A 20% sample of the HEJs examined on the cold leg side of the SGs revealed no indications. One (1) indication was detected in the HEUT, seven (7) in the HRUT, eighty-eight (88) in the HRLT, and one-hundred and thirty-

four (134) in the HELT.[1] The minimum PTI angle reported was 23° and the maximum was 360°. The sleeves had been installed in the tubes in 1983, and were fabricated from thermally treated Alloy 600 material.

4.1.3 Kerncentrale Doel 4 Nuclear Power Plant

Significant in-service leakage was detected from a PTI in SG "G" at Doel 4 in April of 1994 one week before a scheduled outage. The leak was attributed to a throughwall PTI at the HEUT. The tube/HEJ was removed from the SG along with a joint from a randomly selected tube. The indication in the leaking tube had an ID extent of ~180° and an OD extent of ~160°. A PTI was found in the other tube at the same elevation. It consisted of three (3) separate, circumferentially adjacent cracks with an aggregate length of ~5 mm (34°). The deepest crack has been reported as being 90 to 100% throughwall, Reference 16. The PTIs in both tubes were attributed to primary water stress corrosion cracking (PWSCC). A total of 1740 tubes had thermally treated Alloy 690 HEJ sleeves installed in 1993.

The tubes at Doel 4 are considered to be particularly susceptible to PWSCC. During the outage the detection of significant numbers of tubes cracked at the tube/tubesheet hardroll transitions led to the decision to sleeve all of the tubes in the three SGs at that site using laser welded sleeves (LWSs), and to add a laser welded joint to each of the HEJ sleeves at an elevation above the HEUT. During the LWS campaign, fifty (50) additional HEJs were examined using the CECCO 3 probe. Nine (9) of the tubes were indicated to contain PTIs. Six (6) of these were at the HEUT and the remaining three were at the HELT. None of the tubes were indicated to have multiple PTIs.

In the Summer of 1995, a CECCO 3 probe was used to inspect all of the sleeve joints in the three SGs. A + Point probe was also used to inspect 184 of the welded HEJ sleeves. A summary of all findings was not available at the time of preparation of this report. Six (6) of the weld repaired HEJ sleeved tubes were removed for destructive examination. Two of these had been identified as having no detectable degradation (NDD) at the HEUT by the field NDE. These were confirmed to be NDD in the laboratory. The other four HEJs exhibited PTIs by the field NDE. One of these was found to have an ID initiated throughwall crack (~0.5" on the ID and ~0.25" on the OD) at the elevation of the HEUT. This tube broke during the removal operation at a tensile load of ~9700 lb_f. The other specimens had experienced wastage of the parent tube and the Alloy 690 sleeve at the bottom of the closed crevice, i.e., the HEUT, formed when the laser welding was effected. The wastage may likely be due to a concentration of an acidic environment in the ~6" long closed crevice between the HEJ and the repair weld.

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[1] Note that this information is an update of information previously presented, e.g., Reference 15, where it was stated that no indications had been reported in the HRUT. An expert review of the NDE data revealed that the location information was distorted as a result of pulling the probe down into the sleeve from the tube. A reevaluation of all of the PTI elevations was performed only to identify the location of the PTIs by transition, thus average dimensional information was not available at the time of preparation of this report.

4.2 Summary of Field Experiences

In summary, PTIs have been detected in HEJ sleeved tubes at three plants during a total of four inspection outages, two at Kewaunee, one at Point Beach 2, and the initial inspection outage at Doel 4. A summary of approximately all known PTIs is provided in Table 4-3. In total, about 60.5% occur at the HRLT and 37.2% at the HELT. About 0.7% have been found at the HRUT, and the remaining 1.6% at the HEUT. These distributions are illustrated in histogram form on Figure 4-1 and in "pie" chart form on Figure 4-2. The incidence of indications at the upper transitions in plants in the United States (US) comprises about 1.5% of the reported indications. Thus, the distribution at Doel 4 is atypical of the occurrences in the US. In no instances have indications been detected in the same tube at upper and lower transitions.

Approximately 75% of the known PTIs have been found in tubes in the Kewaunee SGs. Hence, it would be expected that the distribution of indications relative to elevation can be characterized by the distribution found at Kewaunee. Figure 4-3 illustrates the distributions of PTIs at the last inspection outage at Kewaunee.[1] Approximately 1% of the indications were judged to be located within 1.1" of the bottom of the HRUT. If an eddy current positioning error of 1/16" is assumed, the number of indications above the repair boundary would be on the order of 4%.

[1] The elevation information is based on an "expert" review of 630 PTIs, or 98% of population of circumferential indications.

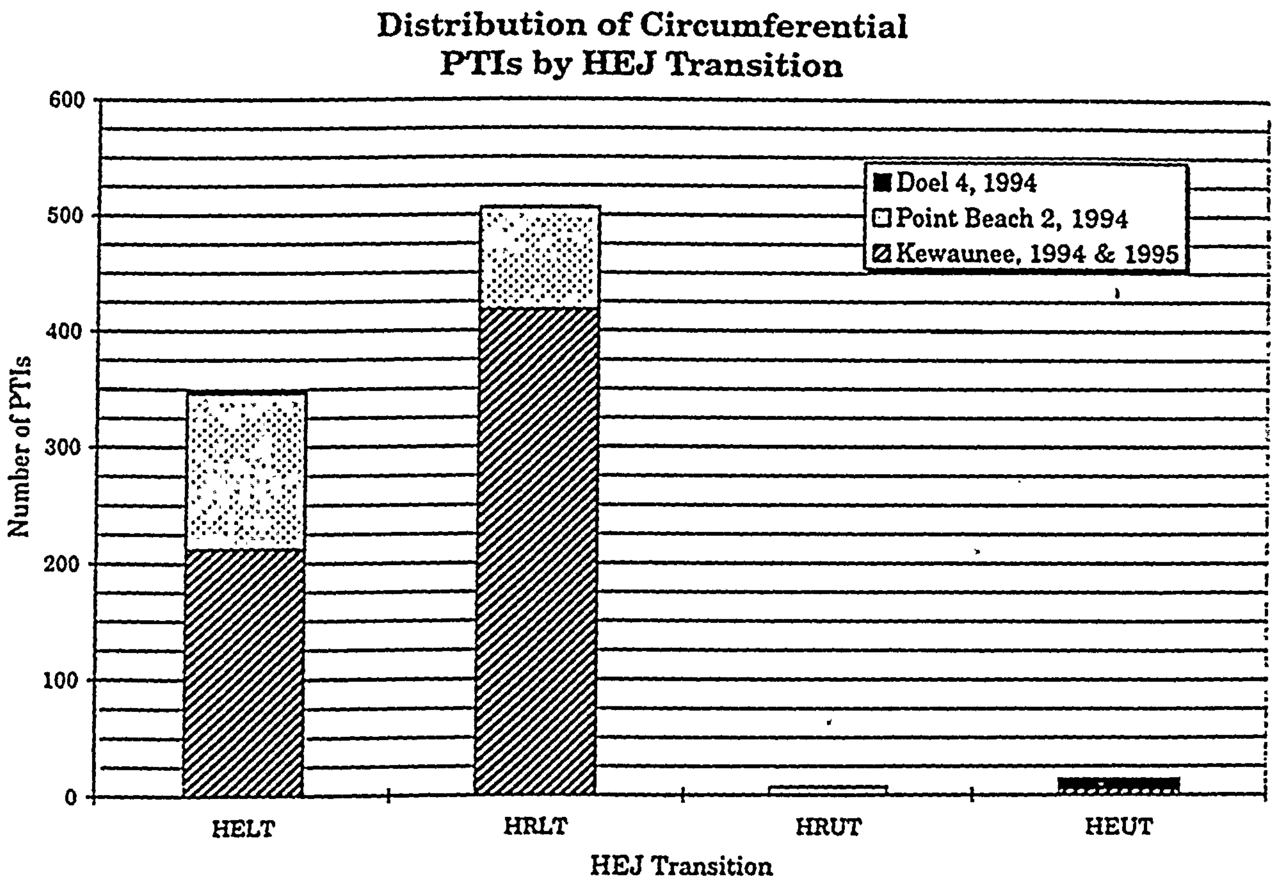
Table 4-1: Distribution of Kewaunee 1994 HEJ Indications Removed from Service by Installation Year			
Installation Year	SG "A"	SG "B"	Both SGs
1988	46	17	63
1989	2	1	3
1991	0	0	0
Totals	48	18	66

Table 4-2: Distribution of Kewaunee 1995 HEJ Indications Removed from Service by Installation Year			
Installation Year	SG "A"	SG "B"	Both SGs
1988	283	152	435
1989	147	69	216
1991	1	5	6
Totals	431	226	657

Table 4-3: Distribution of HEJ PTIs by Transition					
Transition	Kewaunee[1]	Point Beach 2	Doel 4	Totals	Percent
HELT	212	134	3	349	37.2
HRLT	480	88	0	568	60.5
HRUT	0	7	0	7	0.7
HEUT	6	1	8	15	1.6
Totals	698	230	11	939	100
Axials	10	0	0	10	
Volumetric	2	0	0	2	
Totals	710	230	11	951	

Notes: 1. 1995 numbers based on the findings of an "expert" review of the elevations relative to the bottom of the HRUT prior to the final data becoming available.

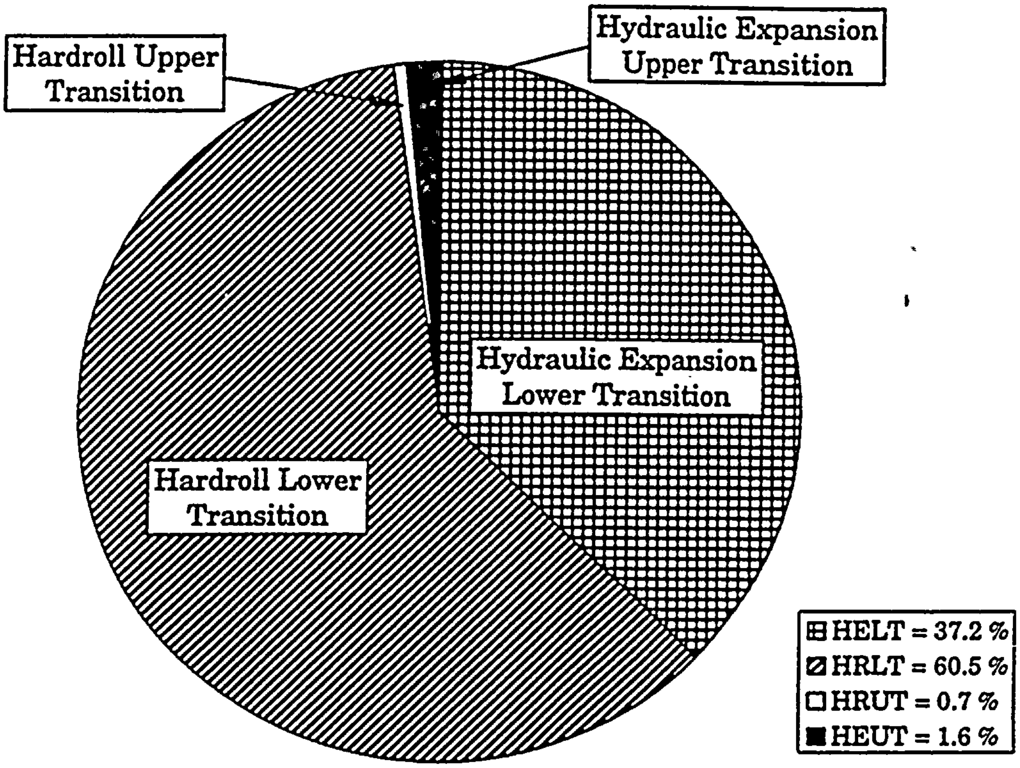
Figure 4-1

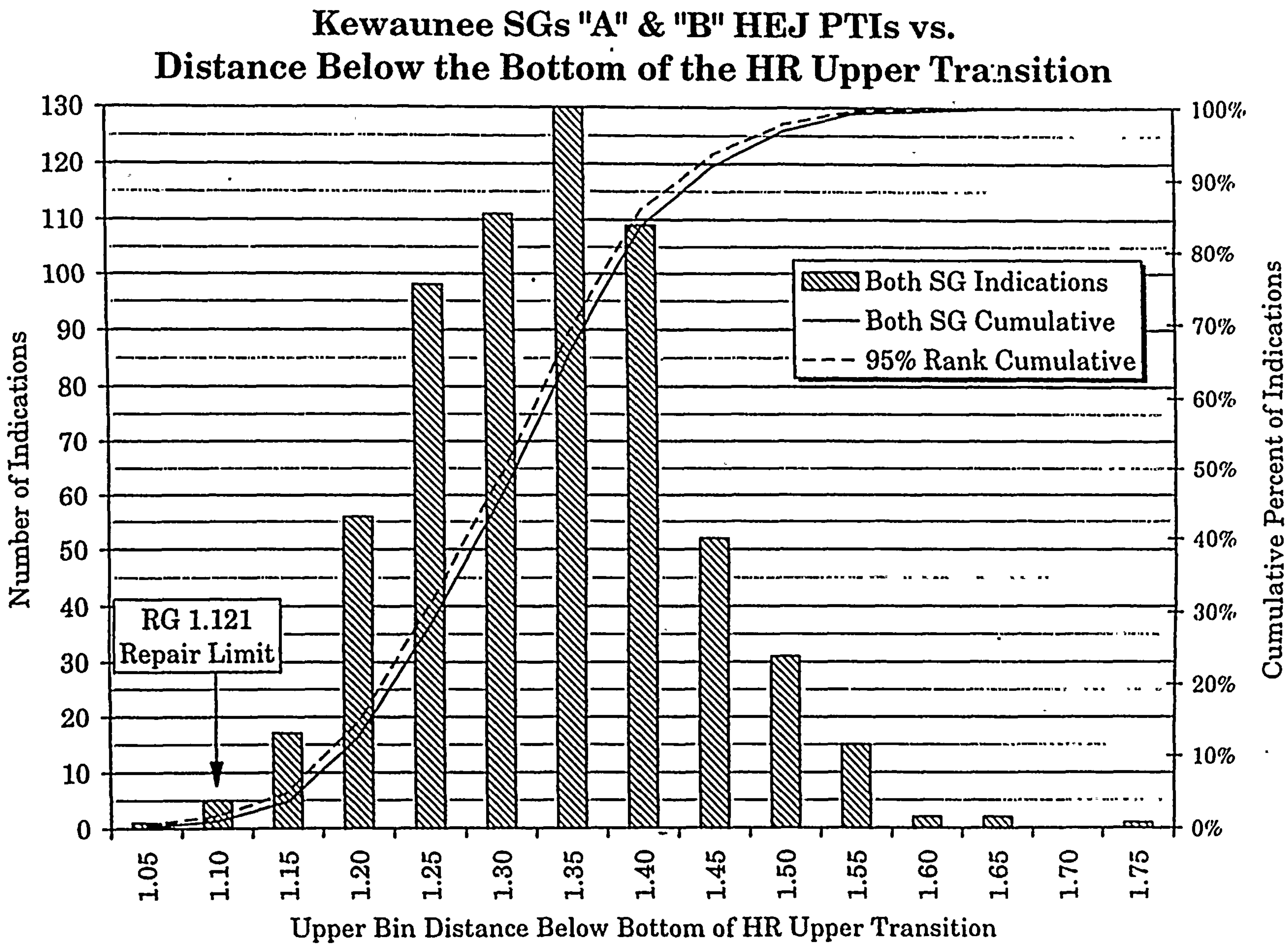


Distribution of Circumferential
PTIs by HEJ Transition
Doel 4, 1994
Point Beach 2, 1994
Kewaunee, 1994 & 1995
600
500
400
300
200
100
0
Number of PTIs
HELT
HRLT
HRUT
HEUT
HEJ Transition

Figure 4-2

Distribution of All Circumferential PTIs by Transition





Kewaunee SGs "A" & "B" HEJ PTIs vs.
Distance Below the Bottom of the HR Upper Transition
130
120
110
100
90
80
70
60
50
40
30
20
10
0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Number of Indications
Cumulative Percent of Indications
Both SG Indications
Both SG Cumulative
95% Rank Cumulative
RG 1.121
Repair Limit
1.05
1.10
1.15
1.20
1.25
1.30
1.35
1.40
1.45
1.50
1.55
1.60
1.65
1.70
1.75
Upper Bin Distance Below Bottom of HR Upper Transition

5.0 Summary of Examinations Conducted on Kewaunee Steam Generator Tubes with Hybrid Expansion Joints

5.1 Introduction

Sections of SG tubes R2C32, R2C54 and R2C61 were removed from the hot leg side of SG "B" at Kewaunee in 1995 to characterize the operating condition of the HEJs which had been installed in these tubes in 1988. The HEJs had been installed to prevent leakage through tube corrosion at top of tubesheet (TTS) and tubesheet crevice locations. The tubes/HEJs were cut 3" above the TTS and 3" below the first tube support plate (TSPs) and were then removed from the secondary side of the steam generator to avoid deformation that would have probably occurred from a primary side tube pull. Consequently, only the upper mechanical joints of the HEJs were available for examination. The upper mechanical joint is described in Section 1 of this report. The tube material was mill annealed Alloy 600, and the sleeve material was thermally treated Alloy 690. The examination was conducted at the Westinghouse Science and Technology Center to characterize any tube/sleeve corrosion. Field eddy current suggested the presence of significant circumferential corrosion at the hard roll lower transition (HRLT) in the upper mechanical expansion of the HEJs.

After nondestructive laboratory examination by eddy current, radiography, dimensional characterization, and visual examination, one HEJ region was leak tested at elevated temperature. Subsequently, room temperature tensile testing was conducted on two of the HEJs, as well as on three free span sections, one from each removed tube. The third tube/HEJ section was retained intact as an archive specimen. The two HEJs which were tensile tested were then destructively examined using metallographic and SEM fractography techniques to characterize any corrosion. In addition, an analysis of the OD and ID deposits, ID oxide films, and fracture face oxide films was performed using EDS, ESCA and AES techniques. In addition, ion chromatography and capillary electrophoresis were performed on soluble ID deposits obtained by water leaching.

5.2 NDE Results

Table 5-1 presents a summary of the more important field and laboratory NDE results. The field eddy current data were conducted using + Point and I coil probes, while the laboratory inspections used + Point, CECCO and RPC probes. Field and laboratory eddy current inspections produced similar data. For the + Point probe, common to both the field and lab exams, the data produced the same signals, suggesting a 360° circumferential indication in the HRLT of tubes R2C54 and R2C61, and a 300 to 360° circumferential indication in the HRLT of tube R2C32. These signals were suggestive of deep, even throughwall degradation. The laboratory CECCO probe data produced similar conclusions with the exception that the circumferential indication in tube R2C32 appeared to be 360° wide, rather than 300 to 360° wide. In addition, the laboratory + Point and CECCO probes suggested the presence of a small indication in the hydraulic expansion lower transition (HELT) of tube R2C61 (the archive specimen). There was no suggestion by field or laboratory NDE of any corrosion degradation being present in the Alloy 690 sleeve.

The radiographic laboratory examination detected a 270 to 360° circumferential band of short semi-continuous circumferential indications in the upper portion of the HRLT of the tube, just below the HR region in tube R2C32. These cracks were confined to a very narrow zone, less than 0.05" high, such that the individual cracks appeared to occur head-to-toe. In addition, a shorter (approximately 300° long) band of cracks was observed approximately 0.1" below the main band of cracks. tube R2C54 had two to three similar bands of short semi-continuous circumferential cracks that occurred over 350° from the mid- to upper portion of the HRLT. Tube R2C61 had one band of short semi-continuous circumferential cracks that occurred over 360° in the mid-portion of the HRLT.

The HRLT was approximately 0.25" long in the case of tube R2C32, and was approximately 0.5" long in the cases of tube R2C54 and R2C61. The HRLT apparently experienced noticeable *rolldown*[1] during installation, especially for tubes R2C34 and R2C6l. In contrast, the HRUTs for all three tubes were approximately 0.1 to 0.2" high. Dimensional characterization of the HE's showed that all three had similar hydraulic and hard roll expansion dimensions that were typical for qualified HEJ installations, e.g., see Figure 1-3. The hardroll regions were expanded 0.009, 0.012 and 0.009" radially above the negligibly expanded hydraulic regions for tubes R2C32, R2C54, and R2C6l, respectively.

5.3 Leak Testing

The R2C54 HEJ was cut to 11" long with the hardroll region centered in the specimen. The bottom 1" of the specimen was then expanded to contact with the tube and the sleeve was then welded to the tube. This seal causes any leak through the hardroll region to occur bnly through the tube HRLT cracks. Elevated temperature leak testing was then performed on tube R2C54 at a variety of conditions that ranged from nominal operating conditions to simulated SLB conditions. No leaks were observed through the tube HRLT cracks at any of the test conditions. The maximum test differential pressure was 2534 psi with corresponding primary and secondary side temperatures of 618 and 611°F.

5.4 Tensile Testing

Table 5-2 provides room temperature tensile properties obtained from a free span (FS) section of each tube. The tensile strengths for the FS section of tubes R2C34 and R2C61 are typical for Westinghouse tubing of this vintage. The tensile strength for tube R2C32 is noticeably higher than typical. Table 5-2 also provides tensile load separation data for the HEJs from tubes R2C32 and R2C54. The 11" long HEJ specimens, with their HR regions centered within the specimens, had the bottom 1" of their sleeves expanded into contact with the tubes. The bottom end was then welded such that the sleeve and the tubing below the cracking in the HRLT would not move relative to each other during the tensile test. The top portion of the 11" long specimens consisted only of tubing because the top of the sleeve ended approximately 3.3" below the top of the tubing. The HEJs were then pulled apart at 0.05" per minute with

[1] In order to remove the rolling tool from the installed sleeve, the direction of rolling is reversed to release the rollers from contact with the ID surface of the sleeve. If the rollers do not immediately retract, additional rolling in the downward direction occurs, resulting in an elongation of the HRLT referred to as rolldown.

the separation load of the HRLT crack network being recorded. In addition, the sliding loads of the HR region of the upper portion of the tubing being pulled over the HR region of the sleeve was also recorded. Both HEJs had high separation loads, 10,300 and 10,700 lbs, respectively. The HR sliding loads decreased continuously over the remaining HR region. Tube R2C32, with the HRLT cracking located at the upper portion of the HRLT (at the bottom portion of the HR), had its sliding load start at 2800 lbs and decrease to 50 lbs at the top portion of the sleeve HR. Tube R2C54, with the HRLT cracking located near the center of the HRLT, had a smaller diameter fracture opening that was required to pass over the sleeve HR region. Consequently, the initial sliding load was higher, 4000 lbs. The sliding load continuously decreased to 200 lbs at the top portion of the sleeve HR.

5.5 Destructive Examination Results

Post-tensile test visual inspection data showed that ID origin, circumferentially oriented, corrosion cracks were present continuously around the circumference of the tube fracture faces of both HEJs that were separated by tensile testing, Figure 5-1. The two HEJ specimens were subsequently given destructive examinations which included SEM fractography of the fracture face openings, visual and SEM inspection of surface features and metallography of secondary corrosion within the HEJ region of the tubing.

The tensile fracture faces of the tubes from the two HEJ tensile specimens were examined by SEM. Table 5-3 presents the results of the fractographic data in the form of macrocrack length versus depth, microcrack length/average and maximum depth, and the number/location/ width of ductile or non-corroded ligaments found on the fracture face. The tube tensile separations occurred in circumferential macrocracks that were composed of numerous circumferentially oriented intergranular microcracks of ID origin that were aligned in a single tight and narrow (< 0.05" high) band in the case of tube R2C32 and in a slightly less tight and narrow (< 0.12" high) band in the case of tube R2C54 where the fracture face jumped from one circumferential crack network to a parallel one. (See radiographic data In Section 5.2.) A large fraction of the many ligaments separating the microcracks on both specimens had ductile features. There were 21 ductile ligaments present in the case of tube R2C32 and 19 ductile ligaments present on the fracture face from tube R2C34. Many other ligaments had only intergranular features.

All intergranular corrosion was confined to and located in the HRLT regions. In the case of tube R2C32 the cracking was at the upper portion of the HRLT and in the case of tube R2C54 the cracking was located from the mid-portion of the HRLT to the upper portion of the HRLT. The fracture faces both had a maximum depth of 92% throughwall, with average depths ranging from 61% (tube R2C32) to 60% (R2C34) throughwall and with microcrack lengths that were 360° long. At some ID locations adjacent to the fracture faces, a few short circumferential microcracks were observed parallel to the fracture face. These microcracks appeared to be simple cracks, morphologically speaking, in that the near absence of oblique angle cracks and blunting was noted. This morphology is more typical of PWSCC than of secondary side corrosion that typically occurs in caustic crevices.

SEM examinations were conducted on the OD and ID surfaces of the balance of the tubing from both tubes in the HEJ regions with the examination concentrating on finding cracks at

other locations and on characterizing deposits. No cracks were observed. ID surface deposits were thin at all HEJ locations. Circumferential and oblique angled ID surface scratches from the honing operation used prior to HEJ installation were clearly present below the HR. Above the HR, similar scratches were observed, but they were frequently obscured by slightly thicker, but still thin deposits. The ID deposits on the tubes in the HR region, including those below the HR region, had the typical appearance of ID surface deposits that were located immediately above the HEJ sleeve. In the case of tube R2C32, local areas with unusual whisker-like deposits were observed just below the fracture face at the top of the HRLT and also at HRUT (hard roll upper transition). At no local crevice location (HR or HE transitions) were thicker or differently colored deposits observed, such as those typically concentrated by boiling.

No corrosion degradation was observed on the OD of the sleeves from both tubes when visual (30X) and SEM examinations were conducted. In comparison, similar examinations conducted on recent Doel 4 HEJs, that had been repaired by laser welding following a cycle of operation, showed some IGA type corrosion in the sleeve and tube. The IGA grain boundaries had very thick oxide layers in both the sleeve and tube at the bottom of a local crevice region.

Following SEM examination (and EDS analysis of deposits which will be presented shortly), a narrow axial metallographic section was cut from each tube through the HEJ region, primarily to obtain microhardness measurements from selected locations. Table 5-4 presents this data. The microhardness at the fracture face location (HRLT) was similar to or slightly higher than other HE and HR transition locations; however, the ID-most microhardness next to the fracture face of both tubes did include two of the three highest hardness values, when appropriately ignoring hardness values taken next to tensile shear surfaces. In addition, no cracks were observed by metallography at locations other than the fracture face location in the HRLT. After small ESCA-AES specimens were cut from just below the lower fracture face of tube R2C32, the remaining portions of the tubes from both HEJ specimens were deformed to open any ID origin cracks such that they could be readily observed by visual inspection (30X). The tube sections were cut axially into to two 180° wide halves. The halves were flattened to open axial cracks. None were observed at any of the hydraulically or hard roll expanded regions. The halves were then bent to open any ID surface circumferential cracks. Again, none were observed at any of the hydraulically or hard roll expanded regions.

Finally, metallographic axial sections were made through the HRLT to the fracture face to characterize the IGSCC that was present in the HRLT. The cracks observed were simple appearing, more similar to that expected from PWSCC than from secondary side corrosion where caustic environments are typically concentrated. From the metallographic and SEM surface examinations conducted on the HRLT corrosion, it was concluded that the only corrosion morphology was ID origin, circumferentially oriented intergranular stress corrosion cracking. The cracks were simple in morphology with only minor D/W ratios measured. (IGSCC morphology can be characterized by D/W ratios where the extent of IGA associated with a given crack is measured by the ratio of the crack depth, D, to the width, W, of the crack at its mid-depth. D/W ratios greater the 20 are defined as minor.)

The microstructures of the removed tubes varied. Tube R2C32 had a moderate to high number of carbides while tubes R2C54 and R2C61 had few carbides. For all three tubes, most carbides were distributed transgranularly rather than intergranularly, the preferred microstructure for PWSCC resistance. The grain size for tube R2C54 was ASTM 8.5, typical of Westinghouse tubing of similar vintage. The grain sizes for tubes R2C32 and R2C61 were somewhat smaller, approximately ASTM 10 and 9.5, respectively. Based on laboratory testing data, these microstructures may have relatively low resistance to PWSCC.

5.6 Surface Chemistry

ID and OD deposit data were obtained from the two destructively examined specimens using energy dispersive spectrometry (EDS). In addition, ID and OD deposit/oxide film and fracture face oxide film data from the fracture face of tube R2C32 was obtained using ABS and ESCA techniques. The following observations are considered the more important from the data obtained. EDS data conducted on the ID surfaces of the both tubes in the HEJ regions provided minimal information since the deposits were thin and most of the EDS signal came from the base metal/oxide layer beneath the deposits. Other than the base metal elements of Ni, Cr, Fe and TI, the only elements detected were O, Al, S, and Si. On the OD, where deposits were thick, the deposits were rich in Fe and O with some observations of Ni, Cu and Zn. The pH of many ID and OD surfaces was determined using deionized water moistened wide-range pH paper. At all locations, the pH readings were neutral.

From the ESCA mid ABS data obtained on tube R2C32:

1) high concentrations of B were observed on the ID surface below the fracture face below the HR region;

2) Cr was not significantly enriched or depleted on either the crack fracture face in the ID surface below the fracture face;

3) low levels of Zn, Na, Mg, SI and S were also detected in addition to the expected C, O, Ni, Cr, and Fe.

Capillary electrophoresis and ion chromatography of water leached soluble ID deposits from a location just below the fracture face of tube R2C32 showed:

1) soluble cations at the following concentrations – Na (0.97 mg/l), Mg (0.25 mg/l), K (0.21 mg/l), Ca (0.21 mg/l), and Li (0.10 mg/l);

2) soluble anions at the following concentrations – SO_4 (1.71 mg/l), Cl (0.28 mg/l), and at least 7 other anions, including organic acid anions.

If it is assumed that the sleeve-tube gap is locally [ ]^{a,c} then the measured concentrations obtained from the 0.15 ml of water are a factor of 100 lower than the actual crevice solution concentrations. That would make the Li concentration in the HRLT crevice 10 mg/l, higher than found in non-concentrated primary water.

Capillary electrophoresis and ion chromatography of water leached soluble ID deposits were also obtained for the hardroll upper transition region. This supplemental leachate test was performed subsequent to an NRC/AEP/W meeting at One White Flint North on August 10, 1995. The leachate test for the hardroll upper transition was performed identically to the leachate test for the hardroll lower transition region. The results of the test indicated that the same soluble cations were detected as for the hardroll lower transition, except they were found in significantly lower concentrations. Potassium, however, was not detected in the hardroll upper transition.

Crevice pH at operating temperature was estimated from the leachate solutions using EPRI's MULTEQ[2] program. The results indicate that the operating temperature pH of the hardroll upper transition was 6.0 while the operating temperature pH of the hardroll lower transition was 8.3. For PWSCC, it is believed that a higher pH condition should be slightly more aggressive. However, in the pH range of interest (6 to 9) the impact of pH is considered to be negligible.

5.7 Conclusions

The tubes in the HRLT of all three HEJs had corrosion present. Metallographic and SEM fractographic data showed that the HRLT region of the tubes had circumferentially oriented ID origin IGSCC. The individual circumferential microcracks associated with the macrocracks were simple cracks, that lacked the complexity usually associated with secondary side corrosion. While many of the microcracks were connected by ligaments with only intergranular features, a large number of ligaments had ductile features present. The maximum depth of corrosion for the 360° long macrocracks was 92% for both tubes R2C32 and R2C54 (tube R2C61 was set aside as an archive specimen) with average depths of 61% and 60%, respectively. Dimensional data suggested that the tubes had experienced typical expansions radially. Two of the tubes (R2C54 and R2C61) did experience significant rolldown during the hardroll procedure, as the HRLT was 0.5" long. Microhardness traces conducted in the HEJ transition locations showed little variation in hardness and values that were similar to free span locations. One location with somewhat higher microhardness values was near the ID surface of the fracture faces of the two tubes and even there the increase was not great. The corrosion morphology observed was simple, typical of PWSCC environments rather than of secondary side crevice environments with a concentrated caustic environment.

The observed corrosion most likely resulted from an environment primarily derived from primary side water. The presence of Li and B on the tube ID surface below the HR region supports this hypothesis. The lack of significant Cr enrichment or depletion on ID surfaces below the HR and on the crack fracture face, and the relative balance of cations and anions indicate a somewhat neutral crevice environment. The fact that many cations and anions were found and that the estimated Li crevice concentration was higher than found in primary water also suggest that there was communication with the secondary side via a crack elsewhere in the tube. It is concluded that the observed corrosion could have been and probably was caused by a PWSCC type environment. The results of the chemistry evaluations of the ID surfaces for the hardroll lower and hardroll upper transition regions suggest the upper transition reqion was subjected to a slightly less aggressive solution than the hardroll lower transition, but it is not believed that this solution chemistry was the driving force for the

cracking. The driving force for the cracking is believed to be attributed to a pure PWSCC effect, with the crevice chemistry representing a secondary effect.

Laboratory and field eddy current probe data correlated well with the corrosion that was destructively found. The + Point and CECCO probes produced very similar and accurate results. Even the RPC laboratory data showed the presence of the corrosion in the tubes despite the presence of the sleeve between the probe and the tube. The destructive examinations verified that there were no cracks in either tube at the HRUT or the HEUT.

Leak rate testing performed at elevated temperatures and pressures simulating normal operating and steam line break conditions produced no leakage for the R2C54 specimen. The tensile separation loads for tubes R2C32 and R2C54 were 10,300 and 10,700 pounds, respectively, and the sliding loads over the hard roll region started at 2800 and 4000 pounds, respectively. The tensile loads were well above any safety considerations.

Table 5-1: Comparison of NDE Indications Observed at Kewaunee on SG Tubes at HEJ Locations

Tube/ Location	Field Eddy Current	Laboratory Eddy Current	Visual/Dimensional Data	Laboratory X-Ray
R2C32	+ Point: 300-360° Circ Ind in HRLT, probably throughwall. I Coil: (1994 data only) ~270° Circ Ind.	+ Point: 300-360° Circ Ind in HRLT, probably throughwall. CECCO: 360° Circ Ind in HRLT, probably throughwall. RPC: >270° Circ Ind at top of HRLT.	HRLT starts 8.25" above bottom of pulled piece or 11.25" above TTS: HRLT is 0.25" long; tube HR OD is 0.907" & HRLT goes 0.009" lower (radially); all values include variable OD deposits.	One to one and one-half semi-continuous Circ networks of short Inds at top of HRLT, observed over at least 270°, possibly 360°.
R2C54	+ Point: 300-360° Circ Ind in HRLT, probably throughwall. I Coil: No data.	+ Point: 360° Circ Ind in HRLT, probably throughwall. CECCO: 360° Circ Ind in HRLT, probably throughwall. RPC: >270° Circ Ind in HRLT.	HRLT starts 6.8" above bottom of pulled piece or 9.85" above TTS: HRLT is 0.50" long; tube HR OD is 0.903" & HRLT goes 0.012" lower (radially); all values include variable OD deposits.	Two to three semi-continuous Circ networks of short crack Inds in mid- to upper portion of HRLT, observed over 360°.
R2C61	+ Point: 300-360° Circ Ind in HRLT, probably throughwall. I Coil: 1994 data only, >270° Circ indication.	+ Point: 360° Circ Ind in HRLT, probably throughwall, and small Ind at HELT. CECCO: 360° Circ Ind in HRLT, probably throughwall. and small Ind at HELT RPC: >270° Circ Ind in HRLT.	HRLT starts 6.7" above bottom of pulled piece or 9.7" above TTS: HRLT is 0.50" long; tube HR OD is 0.905" & HRLT goes 0.009" lower (radially); all values include variable OD deposits.	One semi-continuous Circ network of short crack Inds in mid-portion of HRLT, observed over 360°, but less continuously than for R2C32 Inds.

Legend of Abbreviations

HR = Hardroll	HELT = HE lower transition	RPC = Rotating pancake coil	Ind = Indication
HE = Hydraulic expansion	HRLT = HR lower transition	TTS = Top of tubesheet	Circ = Circumferential

Table 5-2: Tensile Data for Kewaunee SG Tube Sections			
Kewaunee Free Span Tensile Data			
Tube	Yield Strength (psi)	Ultimate Tensile Strength (psi)	Elongation (%)
R2C32	72,200	123,300	22.0
R2C54	58,600	106,700	24.5
R2C61	55,400	104,000	23.1
Control (NX8161)	52,300	101,500	18.5 *
* Broke outside of the gage length, probably reducing the elongation value.			
Kewaunee HEJ Tensile Data			
HEJ Specimen	Fracture Load (lbs)	Fracture Location	Sliding Load over HR Region (lbs)
R2C32	10,300	Top of HRLT	2800 decreasing to 50
R2C54	10,700	Middle of HRLT	4000 decreasing to 200
R2C61	NA (Archive)	NA (Archive)	NA (Archive)

Table 5-3: Kewaunee SG Tube Macrocrack Profiles for Tensile Fracture of HEJs			
Tube, Location	Length vs. Depth and Ductile Ligament Location (degrees / % throughwall)	Ductile Ligament Width (in.)	Comments
R2C32, HRLT	00/52 22/77 ← Ligament 21 (32/92) ← Maximum depth ← Ligament 20 45/88 ← Ligament 19 58/85 ← Ligament 18 90/88 ← Ligaments 16 & 17 112/88 ← Ligament 15 135/83 ← Ligament 14 158/82 ← Ligaments 12 & 13 180/64 ← Ligament 11 202/76 ← Ligament 10 225/60 ← Ligament 9 248/52 ← Ligament 6, 7, & 8 270/08 292/05 ← Ligament 4 & 5 315/46 ← Ligament 1, 2, & 3 338/29 (Average macrocrack depth = 61% over 360°; maximum depth = 92%)	L21 = 0.004" wide L20 = 0.006" wide L19 = 0.011" wide L18 = 0.003" wide L16, L17 = 0.006", 0.011" wide L15 = 0.008" wide L14 = 0.004" wide L12, L13 = 0.002", 0.003" wide L11 = 0.039" wide L10 = 0.027" wide L9 = 0.014" wide L6, L7, L8 = 0.002", 0.006", 0.012" wide L4, L5 = 0.015", 0.022" wide L1, L2, L3 = 0.015", 0.005", 0.012" wide	Twenty-one ligaments were observed on the circumferential macrocrack located at the top of the HRLT. All intergranular corrosion was of ID origin.

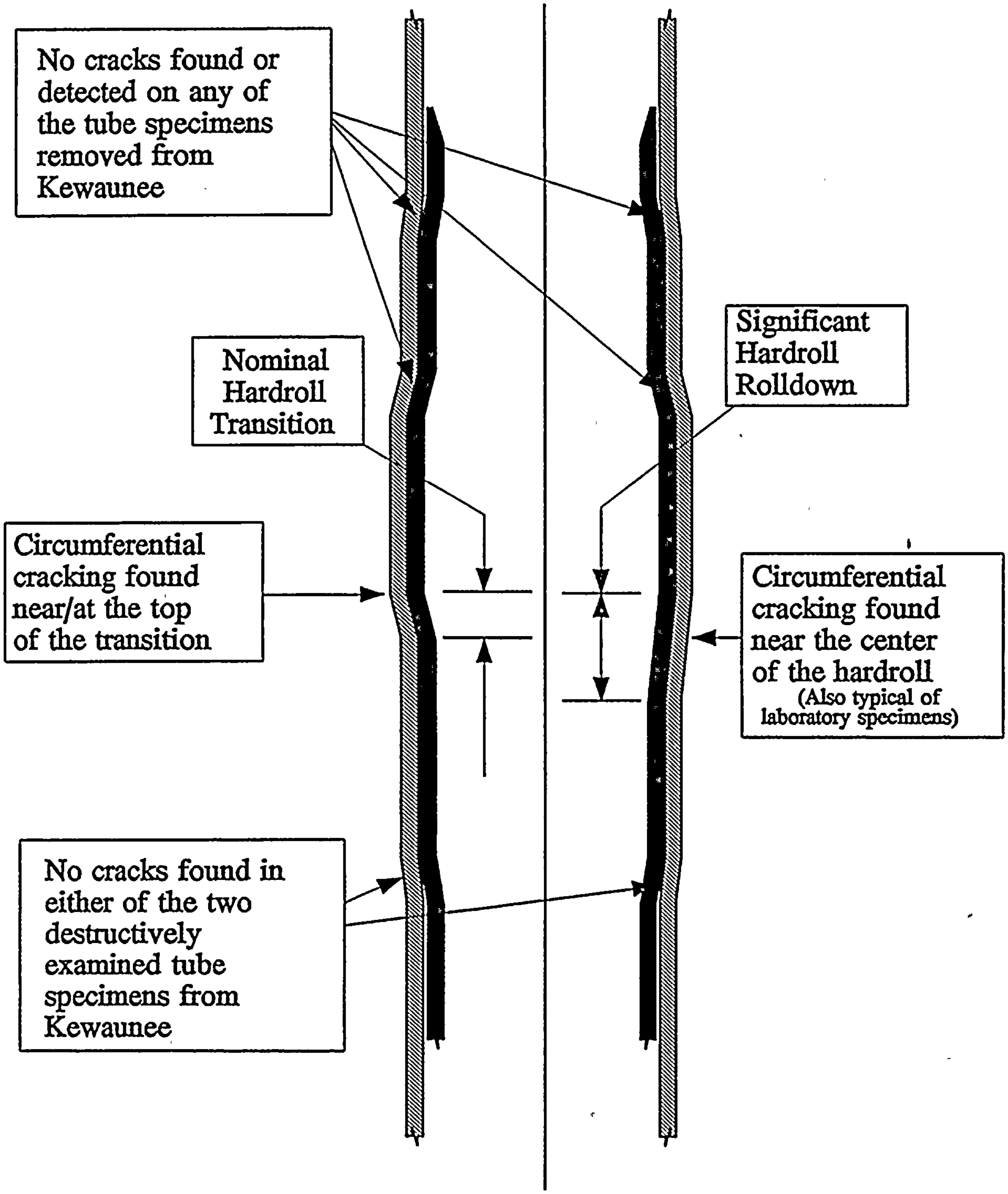
Table 5-3 (Cont.): Kewaunee SG Tube Macrocrack Profiles for Tensile Fracture of HEJs			
Tube, Location	Length vs. Depth and Ductile Ligament Location (degrees / % throughwall)	Ductile Ligament Width (in.)	Comments
R2C54, HRLT	00/04 ← Ligaments 17 & 18 22/67 ← Ligaments 14, 15, 16 45/75 68/84 (80/92) ← Maximum depth ← Ligament 13 90/78 112/82 135/72 ← Ligament 12 158/74 ← Ligaments 10 & 11 180/74 ← Ligament 9 202/56 ← Ligament 8 225/16 ← Ligament 7 248/48 ← Ligament 5 & 6 270/64 292/78 315/70 ← Ligament 2, 3, & 4 338/22 ← Ligament 1 & 19 (Average macrocrack depth = 60% over 360°; maximum depth = 92%)	L17, L18 = 0.015", 0.005" wide L14, L15, L16 = 0.003", 0.008", 0.007" wide L13 = 0.017" wide L12 = 0.009" wide L10, L11 = 0.017", 0.005" wide L9 = 0.011" wide L8 = 0.050" wide L7 = 0.002" wide L5, L6 = 0.009", 0.007" wide L2, L3, L4 = 0.008", 0.013", 0.013" wide L1, L19 = 0.013", 0.044" wide	Nineteen ductile ligaments were observed on the circumferential macrocrack located in the middle of the HRLT. All intergranular corrosion was of ID origin.

Table 5-4: Microhardness Measurements (VHN, 500 gm load) on Kewaunee HEJ Sleeved Tubes

Tube/Location	Microhardness at Specified Depth from Tube ID Surface					
	0.001"	0.006"	0.016"	0.026"	0.036"	0.046"
R2C32, HELT	196	193 [1]	183 [2]	181 [2]	191 [2]	196 [2]
HRLT	209	209	204	193	204	209 [3]
HRLT next to FF	238 (IGSCC)	228 (IGSCC)	218 (IGSCC)	252 (shear)	268 (shear)	no data, necked
HR	215	212	204	204	209	218
HRUT	186	193	186	186	191	198
HEUT	193	196	188	188	196	198
FS 4" above HEJ	198	186 [4]	179 [4]	181 [4]	186 [4]	188
R2C54, HELT	193	196	181	174	181	188
HRLT	196	196	181	172	183	188 [5]
HRLT	231 (IGSCC)	215 (IGSCC)	215 (IGSCC)	221 (shear)	234 (shear)	no data, necked
HR	241	228	221	212	215	221 [6]
HRUT	212	204	193	191	193	206 [6]
HEUT	176	186	176	181	183	176 [3]
FS 4" above HEJ	176	174	172	156	166	174

Notes:
1. Located 0.002" closer to the ID surface than indicated
2. Located 0.007" closer to the ID surface than indicated
3. Located 0.002" farther from the ID surface than indicated
4. Located 0.005" farther from the ID surface than indicated
5. Located 0.005" closer to the ID surface than indicated
6. Located 0.004" closer to the ID surface than indicated

Location of Cracks in HEJ Sleeved Tubes Removed from Kewaunee



HEJ-DOWN.WPG

Figure 5-1

6.0 Structural Integrity and Leak Rate Evaluations

In order to quantify the effect of the tube indications on the operating performance of HEJs with PTIs, test and analysis programs were performed, References 8 and 9, aimed at:

1) characterizing the effect of the observed PTIs on the axial strength of the joint, and

2) estimating the leak rate that could be expected during normal operation and under postulated SLB conditions for the case of a tube perforated below the hardroll.

Characterization of the axial strength of the joint in the event of tube degradation of the type indicated in the Kewaunee and Point Beach 2 tubes (no indications have been determined to be present in the Cook 1 tubes at present) was explored via axial tensile testing and hydraulic proof testing. Additional analyses results were reported in References 11 and 12. A summary of the test and analysis programs is provided in the following sections. The results are applicable to the four U.S. plants with installed HEJs. Plant operating parameters relative to suructural integrity evaluations are presented in Table 6-1. The largest operating primary-to-secondary differential pressure, 1535 psi, occurs in the SGs at Kewaunee, although Cook 1 is approved to operate up to 1600 psi. The smallest differential pressure, 1225 psi, occurs at Point Beach 2. The current differential pressure at Cook 1 is 1453 psi. The axial end cap loads during normal operation, and the RG 1.121 3ΔP loads, are summarized in Table 6-2. The maximum 3ΔP load is 2172 lbs (could be as high as 2264 lbs) and the minimum is 1734 lb_f. Since each of the plants have 7/8" nominal diameter tubes with 0.050" thickness, the end cap load during a postulated SLB event is 1516 lbs regardless of the plant. Thus, the 3ΔP end cap load governs the analysis.

6.1 Structural Integrity Tests

Two types of structural tests were performed, tensile strength tests and hydraulic proof tests (References 8 and 9). Prototypic HEJ test specimens, see Figure 6-1, were fabricated using Alloy 600 tubing and both Alloy 600 and Alloy 690 sleeve material.[1] The initial tensile strength tests were performed on prototypic HEJ sleeved tube specimens with the lower portion of the tube completely machined away at various postulated crack elevations. For specimens where the tubes were completely removed by machining at the elevation corresponding to the bottom of the HRLT, i.e., ~1.25 inches below the bottom of the HRUT, the structural capability of the joints were approximately twice the most limiting RG 3ΔP end cap loading. For specimens where the tubes were completely removed by machining at the elevation corresponding to the approximate midspan of the hydraulically expanded region, i.e., ~2.25" the bottom of the HRUT, the structural capability of the joints were ~3.5 to 4 times the most limiting RG 1.121 3ΔP end cap load.

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1 The tensile tests demonstrated that the performance of Alloy 600 thermally treated sleeves (utilized in the 1983 Point Beach 2 sleeving campaign) was similar to that of Alloy 690 sleeves.

The structural proof tests were performed on specimens which had been fabricated for leak testing. Following the leak tests, the sleeved tubes were machined to simulate a 360° circumferential throughwall crack at the inflection point, i.e., middle, of the hard roll. All of the samples were then pressurized to a differential pressure of 3657 psi. The pressure was then gradually increased until slipping of the joint was noted. Initial slippage of the tubes was generally detected after an increase in the pressure of about 200 to 700 psi. The maximum pressures, i.e., those achieved when the tube was ejected from the sleeve, were not recorded, but did approach pressures on the order of three times normal operating pressure differentials.

6.2 Pulled Tube Structural Tests

Section 5.0 of this report documented the results of leak and structural tests performed on the sleeved tube specimens removed from SG "B" at Kewaunee, see Table 5-2. The tensile test results for both tubes are higher than that predicted by for the limit load. Tube R2C32 was found to have a high flow stress, ~98 ksi, and an average depth of the cracking of 61%. The cracking was near the top of the HRLT. The estimated limit load of the remaining ligament is 5980 lbs using a net section stress approach. The measured failure load for the specimen was 10300 lbs with a remaining slip load immediately after the failure of 2800 lbs. Estimating the actual failure load of the remaining ligament as the total failure load minus the residual sliding load yields 7500 lbs. This is about 25% higher than the value predicted by analysis. The residual sliding load is about 60% larger than the maximum of two values obtained from tests reported in WCAP-14157 for 360° slits at the top of the HRLT. The sliding load following development of a 360° fracture is about four times, or 25% higher than the RG 1.121 requirement, the end cap load that would be experienced during normal operation of the plant with the highest differential pressure. Moreover, the sliding load is almost three times, or twice the RG 1.121 requirement, the end cap load that would result during a postulated SLB event.

Tube R2C54 had a measured flow stress of ~83 ksi, with an average depth of cracking of 60%. The cracking was at the approximate middle of the HRLT, which exhibited evidence of rolldown. The measured failure load was 10700 lbs with a residual sliding strength of 4000 lbs. Thus, the ligament failure load was on the order of 6700 lbs. This is about 30% higher than the calculated ligament limit load of 5170 lbs. The residual sliding load is about equal to the lower of two values obtained from tests reported in WCAP-14157 for a 360° slit at the bottom of the HRLT, and about equal to the average of three values reported in the Addendum to WCAP-14157. Thus, the residual sliding load for the field specimen with a 360° separation at the inflection point is on the order of that obtained from test speciments with a 360° separation at the bottom of the HRLT. In addition, the sliding load is on the order of six times the end cap load due to normal operation and about four times the end cap load developed during a postulated SLB event.

6.3 Structural Integrity Analyses

The structural analyses presented in References 8, 11, and 12 considered a model of the degraded tube cross-sectional area subjected to the applied loads as shown in Figure A-2

(Appendix A). The purpose of the analyses was to support the development of a repair boundary which included consideration of PTIs located at the top of the HRLT. Such indications are not a subject of this report. The criterion supported by this report is that all PTIs located below a distance of 1.1" below the bottom of the HRUT can be left in service regardless of depth or circumferential extent. Thus, the structural integrity analyses consist of the evaluations of the test data reported in WCAP-14157 and its addendum, and of the test data obtained from the sleeve/tube joints removed from SG "B" at Kewaunee.

6.4 Leak Rate Tests and Analyses

References 8 and 9 documented the results of elevated temperature leak tests that were performed using prototypic HEJ specimens which had the tube portion machined away at the top, the midpoint and at the bottom of the HRLT. The specimens with the tube removed at the bottom of the HRLT exhibited leak rates on the order of 0.0012 gpm, with maximum of 0.008 gpm, at SLB conditions. A summary of the leak rates from specimens with the tube removed or cut at an elevation corresponding to the top of the HRLT or at the repair boundary is provided in Table 6-3. The specimens with the tube removed at the midpoint of the HRLT[2] exhibited a maximum leak rate of 0.016 gpm at SLB conditions. The average leak rate for all of the specimens listed in Table 6-3 is about 0.004 gpm with a standard deviation of 0.008 gpm, thus, demonstrating a significant resistance to primary-to-secondary leakage. These tests suggest that the presence of a "lip" of tube material below the top of the HRLT provides sufficient leakage restriction. The repair boundary determined from structural considerations, i.e., 1.1" below the bottom of the HRUT, would be expected to result in acceptable leak rates during a postulated SLB event.

6.5 Crack Growth Rate Considerations

Since the HEJ has been demonstrated to meet the requirements of RG 1.121 for full circumference, i.e., 360°, at the elevation of the middle of the HRLT, the strength relative to those requirements is independent of crack growth rates.

6.6 Additional Tube Integrity Considerations and Observations

The repair boundary developed in this report does not assume any credit for the resistance to tube motion afforded by tube support plate denting. The presence of significant dents could preclude any tube integrity issues in HEJ sleeved tubes with PTIs. A review of pull forces required to remove tubes from Westinghouse Model 44 and 51 steam generators was discussed in WCAP-14157. For tubes with no significant interface loading within the tubesheet, pull forces for tubes without detectable denting ranged from 1000 to 3000 lbs, while for tubes with detectable dents, the forces rose to 2000 to 4000 lbs.

Based on the findings from the destructive and nondestructive examinations of the specimens removed from Kewaunee, Section 5.0, and from the results of accelerated corrosion tests per-

2 Approximately 1.12 to 1.13 inch below the bottom of the HRUT.

formed by Westinghouse, the appearance of PTIs in joints experiencing significant rolldown may be likely to occur at a lower elevation than in joints without significant rolldown. Approximately 90% of the PTIs at Kewaunee were found at distances ≥ 1.3" from the bottom of the HRUT, thus implying the presence of significant rolldown. Hence, it is possible that transitions with significant rolldown are less resistant to PWSCC than transitions without significant rolldown.

6.7 Conclusions

The specified repair boundary is supported by structural and leak test data obtained from surrogate specimens (WCAP-14157 w/addendum), and by structural data obtained from specimens removed from an operating SG. Tube rupture loads well in excess of those required by RG 1.121 have been demonstrated by both the surrogate and actual HEJ test programs. The repair boundary results in a radial overlap of the HRLT of approximately 0.1" in length. This is a geometric configuration for which neither significant tube axial displacement nor significant tube leakage would be expected to occur during a postulated SLB event.

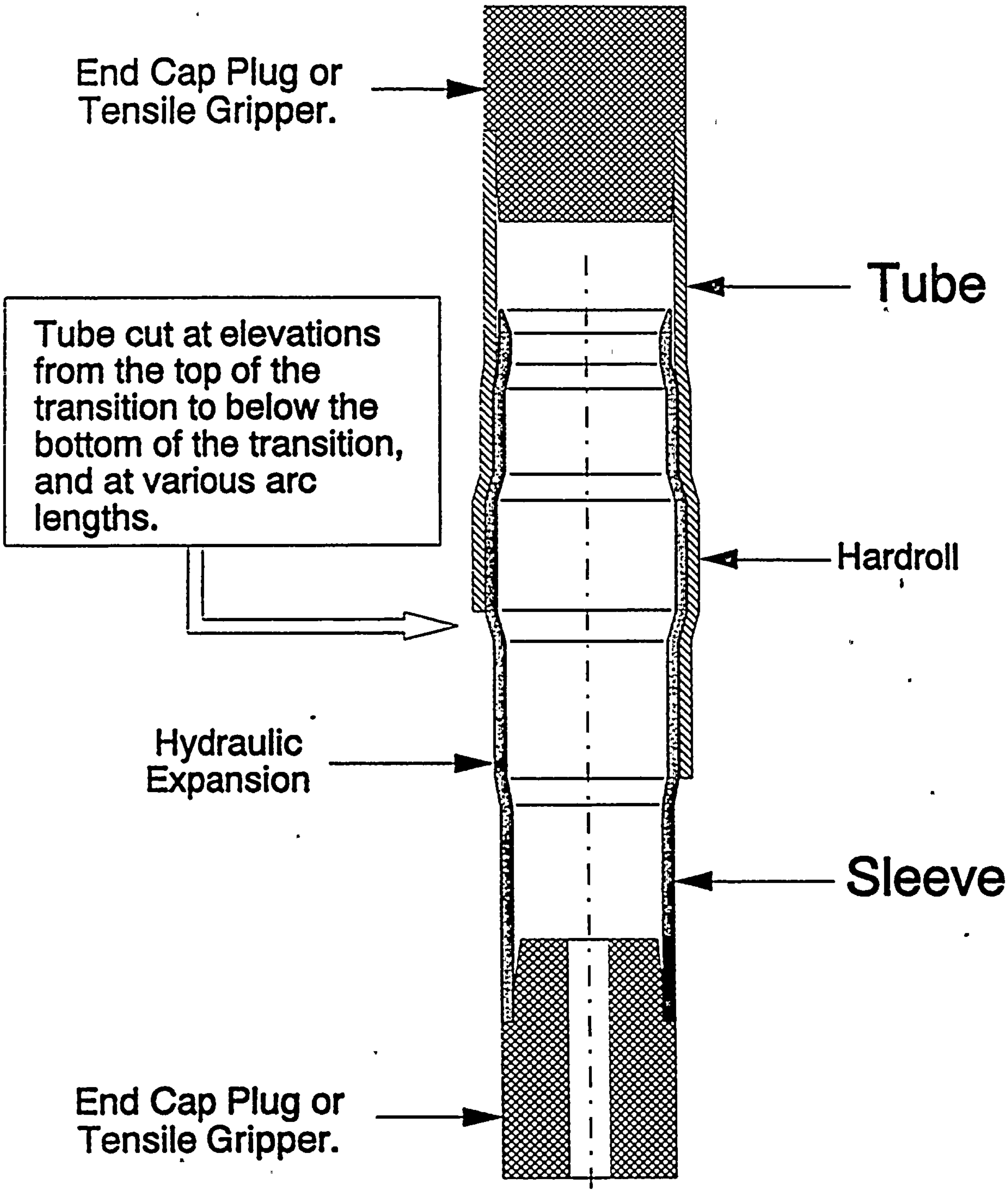
Table 6-1: Operating Parameters for U.S. Plants with Installed HEJs							
Plant	SG	Loops	P_P (psia)	P_S (psia)	ΔP (psi)	T_{hot} (°F)	T_{cold} (°F)
Point Beach 2	44	2	2000	775	1225	596.7	541.7
Cook 1	51	4	2100	647	1453	582.0	518.0
Kewaunee	51	2	2250	715	1535	591.2	531.8
Zion 1	51	4	2250	725	1525	592.2	532.2

Table 6-2: Tube Pressure Loading for U.S. Plants with Installed HEJs			
Plant	Normal ΔP (psi)	Normal ΔP Load (lbs)	3•ΔP Load (lbs)
Point Beach 2	1225	578	1743
Cook 1	1453	685	2056 [1]
Kewaunee	1535	724	2172
Zion 1	1525	719	2158

Note:
1. The 3•ΔP load at Cook 1 could be as high as 2264 lbs corresponding to an operating differential pressure of 1600 psi.
2. The end cap load during a postulated SLB event is 1516 lbs independent of plant.

Table 6-3: Summary of Applicable HEJ Leak Rates from WCAP-14157 and Addendum				
Sleeve Material	Cut Angle (°)	Distance from HRUT (in.)	Leak Rate[1] at 1600 psi (gpm)	Leak Rate[1] at 2560 psi (gpm)
Alloy 690	240	1.08	0.0	0.0
Alloy 690	240	1.01	0.0	9×10^{-6}
Alloy 690	240	1.03	0.0084	0.0186
Alloy 690	240	1.0 +	0.0	4.5×10^{-5}
Alloy 690	360	~ 1.1	0.0	2×10^{-5}
Alloy 690	360	~ 1.1	0.0016	0.016
Alloy 600	360	1.1	0.0	1×10^{-5}
Alloy 600	360	~ 1.1	0.0	1×10^{-5}

Notes: 1. Leak rates for specimens with 240° cut angles were increased by a factor of 1.5 to estimate the leak rate for a cut angle of 360°.



HEJ-TEST.WPG

Figure 6-1: HEJ specimen used for tensile testing.

7.0 Leak Rate Based Repair Boundary

7.1 Introduction

The purpose of this section of the report is to present an alternative method for establishing a repair boundary for HEJ sleeved tubes with PTIs. The PTIs are assumed to be circumferential cracks in the parent tube within the upper sleeve/tube joint region, but below the primary-to-secondary pressure boundary at the sleeve/tube hardroll interface. The previous sections discussed and summarized, considering information obtained from the metallographic examination of HEJ sleeved tubes from Kewaunee, an evaluation of the structural integrity of tubes with PTIs as originally documented in References 8, 9, 11 and 12. The structural evaluations directly support the identification of a repair boundary for PTIs based on the residual strength of the joint. It is also possible to develop a repair boundary for PTIs in sleeve/tube joints which is not sensitive to the residual strength of the joint, and, in essence, is based on the potential total leakage from the degraded joints during a postulated SLB event. A leak rate based repair boundary which is a function of the installed geometry of the tubes and the HEJs is developed in this section. Since the repair boundary is based on geometry and total leakage, it does not rely on the residual strength of the joint or on the extent of the indications, or the growth rate of the indications. The repair boundary does rely on the axial location of the PTI and the constraining effects of outboard neighboring tubes.

The HEJ consists of a HE of the sleeve and tube over a length of 4" beginning approximately 1/2" below the top of the sleeve, followed by a hardroll (HR) over a length of 1" to 1.5" beginning about 1" below the top of the hydraulic expansion. The existing plant Technical Specification sleeved tube repairing/plugging criteria apply to the entire length of the sleeve, and to that portion of the parent tube above the bottom of the HE of the HEJ. An example of the plugging criteria developed at the time of the installation of the sleeves are illustrated on Figure 3.5.4-1 of Reference 5.

This evaluation forms the basis for the development of a repair boundary below which the need to remove a HEJ sleeved tube from service due to the presence of PTIs in the region extending downward from the upper part of the HRLT, e.g., see Figure 7-1. The integrity of the tube bundle with PTIs under normal operating and postulated accident conditions is addressed. The results of the evaluation apply to sleeved tubes in Westinghouse Model 44 and 51 steam generators with partial depth rolled tubes. Three aspects of bundle integrity are addressed:

1) maintenance of a fixed tube-to-sleeve end condition in the limiting case of a circumferential indication near the top of the lower transition of the hardroll,

2) limitation of primary-to-secondary leakage consistent with accident analysis assumptions, and

3) maintenance of tube integrity under postulated limiting conditions of primary-to-secondary and secondary-to-primary differential pressure.

The result of the evaluation is the identification of a distance below the bottom of the HRUT for which PTIs of any extent do not necessitate remedial action, e.g., plugging. The basis of the repair boundary is that the axial distance a postulated severed HEJ sleeved tube end can move is limited by the constraint afforded to the affected tube by it's outboard neighbor. Thus, "hop off" of the upper portion of a severed parent tube will be precluded, and the leakage from such tubes during a postulated SLB will be within acceptable limits. For example, for the Kewaunee SGs the total allowable primary-to-secondary leak rate from all sources during a postulated SLB event was determined in Reference 30 to be 34.0 gallons per minute (gpm), without benefit of reducing primary coolant activity. Interim plugging criteria (IPC) have been approved for dispositioning tube indications at the elevation of the tube support plates in the D.C. Cook and Kewaunee SGs. The expected contribution to the total primary-to-secondary leakage from the IPC indications is likely on the order of 1 gpm or less. Thus, approximately 33.0 gpm total leak rate from HEJ PTIs could be tolerated without exceeding the 10CFR100 limit for the Kewaunee plant.

Application of the leakage based repair boundary is expected to provide the same level of protection for PTIs in HEJ sleeved tubes as that afforded by Regulatory Guide (RG) 1.121 for degradation located outside the sleeve joint. Since the repair boundary does not rely on the residual strength of the joint, the calculation of margins against burst for the affected tube are not meaningful. For each affected tube, the repair boundary does rely on the structural capability of that tube's outboard neighbor. By restricting the application of the criteria to tubes with a structurally capable outboard neighbor.[1]

7.2 Sleeved Tube Dimensions

A summary of the sleeve and tube dimensions pertinent to this evaluation were illustrated in Section 1 of this report. The tubing has a nominal outside diameter (OD) of 0.875" and a thickness of 0.050". The sleeves have an [

]^{a,c}. The region of the hardroll is denoted by the label *interference fit*. The length of this region is governed by the length of the hardrolling tool used to create this section of the joint. For the D.C. Cook, Kewaunee, and Point Beach 2 SGs, the rollers had a flat length dimension of 1.0". Thus, the length cannot be less than 1.0" on the ID of the sleeve. In some cases the length of the hardroll is greater than 1.0" as a result of the reversal of the rolling process in order to release the roller from the inside of the sleeve. This reversal process is usually termed *rolldown* and the additional length of the hardroll is referred to as the rolldown length. It is not unusual for the rolldown to achieve a length of greater than ~0.5" during the reversal process.

The radii of the upper end of the rollers of the rolling tool were [

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1. Limitations on the use of the leak rate based repair boundary are discussed in the evaluation section of this report.

]^{a,c}. Hence, a bounding lower limit on the radius at the OD of the sleeve in the transition is approximately 0.288". A true estimate of the radius of curvature in the axial direction is obtained by considering a hardroll transition length of 0.21" and a radial difference of 8 mils leads to the calculation of an effective radius of 1.4". The [

]^{a,c}, thus, the effective length of the hardroll would be about 60 mils longer before the contact pressure between the sleeve and the hardroll would be lost. This would be somewhat offset by the potential contraction of the tube during the hydraulic expansion process. The expansion of the tube is about [

]^{a,c}. Since the sleeves installed in the D.C. Cook, Kewaunee, and Point Beach 2 SGs were fabricated of Alloy 690, their coefficient of thermal expansion is greater than that of the tubes. This would lead to a slight increase in the interference fit during operation as further increase the effective length of the hardroll, however, the expected magnitude of such an increase would not be expected to be significant.

7.3 U-Bend Clearance

The results of a study of SG fabrication practices, Reference 17, were evaluated in order to estimate the potential distance that a severed HEJ sleeved tube end could displace in the vertical direction during normal operation or during a postulated SLB. The results of this evaluation are applicable to the development of a plugging repair boundary for PTIs in sleeved tubes. In SGs of the type installed at D.C. Cook, Kewaunee, Point Beach 2, i.e., Westinghouse Model 44 and 51, the nominal vertical clearance between radially adjacent tubes at the apex of their U-bends is 0.406". The actual clearance will vary about the nominal due to tube installation tolerances during manufacture of the SGs. The potential contributing factors from the Model 44/51 SG manufacturing operations are:

1. The tube-to-tubesheet fit-up for welding.
2. The tube expansion process.
3. Tube dimensional tolerances on overall length, U-bend radius, tube diameter, etc.

The second operation does not significantly contribute to the manufacturing process tolerance since the tube-to-tubesheet joint process for the D.C. Cook, Kewaunee, and Point Beach 2 SGs involved partial depth rolling as opposed to full depth rolling.

The maximum tube-to-tube U-bend apex gap increase in the D.C. Cook, Kewaunee, and Point Beach 2 SGs as a result of the first and third operations was calculated to be [

]^{a,c}. The extremes of the total manufacturing tolerance are taken to be three standard deviations from the mean, hence, one standard deviation would be [ ]^{a,c}". Since the installation of one tube is independent of its inboard neighbor, the standard deviation of the manufacturing clearance, i.e., the difference between two radially adjacent tubes, may be

calculated as the square root of the sum of squares of the individual standard deviations. Thus, the standard deviation of the U-bend apex gap between two radially adjacent tubes would be [ ]^{a,c}.

An additional consideration in estimating the U-bend apex clearance between two radially adjacent tubes is due to the [

]^{a,c}, assuming that a primary-to-secondary pressure difference of 2560 psi is achieved during the event. Assuming the distribution of U-bend apex gaps to be normally distributed in the SG, an upper 95% confidence bound on the apex clearance is calculated to be [ ]^{a,c}.

The U-bend apex gap can be used to estimate the maximum upward displacement of a tube end which is assumed to be severed within the HEJ. The driving force for such displacement will be the unbalanced pressure on the interior of the tube acting on the projection of the tube cross-section area at the tangent point between the U-bend and the straight length of the tube, i.e., the severed tube end is pulled up by the force at the U-bend. Once contact has occurred with an outboard neighbor, further displacement is prevented. The total vertical displacement may be estimated by calculating the distance that the affected tube's tangent point may traverse by considering that the inboard tube deforms into intimate contact with the outboard tube up to the apex of the U-bend. More extreme deformation would require lateral in-plane deformation which is opposed by the internal pressure. Moreover, the extent of intimate contact would likely be limited to the point of first contact, which would be expected to occur nearer to the midway point from the tangent point to the apex. If d is the tube-to-tube clearance at the apex of the U-bend, and R is the radius of the U-bend of the affected tube, the clearance at the tangent point, D, is

$$D = (R + d)\sin\left[\frac{\pi}{2}\frac{d}{R + d}\right] \leq \frac{\pi}{2}d. \tag{7.1}$$

Using the upper 95% confidence bounds of the U-bend apex clearance results in upper bounds on the tangent point displacement of [ ]^{a,c} respectively. The expected displacement would be between the two extremes. Taking the average of the apex and the maximum tangent point displacements results in expected displacement limits of [

]^{a,c}, with a limiting value of the expected displacement of 1.1". Since this result is based on a 95% confidence level, it would be expected that the occurrence of multiple tubes achieving this level of displacement would be very unlikely. Furthermore, because the length of the sleeve above the bottom of the HR is on the order of 2.75", joint separation, i.e., hop-off, is precluded for tubes with PTIs below the top of the HRLT.

Since hop-off is precluded, the pertinent basis for the development of the leak rate repair boundary is the potential leakage from tubes with throughwall, 360°, PTIs which could displace upward either during normal operation or during a postulated SLB. The potential displacement during a postulated SLB is greater than that during normal operation, as is the primary-to-secondary differential pressure, hence, it is appropriate to develop the repair boundary based on the consideration of potential leakage during a postulated SLB. Vertically displaced severed tube conditions are illustrated on Figure 7-2. The expected displacement for a tube end severed at the top of the hardroll lower transition would be about midway along the length of the hardroll, with a 95% confidence bound on the displacement such that the location of the severed end would be about even with the top of the hardroll. Indications below the top of the hardroll would not be expected to lead to a configuration such that the severed end could achieve an elevation coincident with the top of the hardroll.

The effective length of the hardroll was estimated in the previous section to be 1.03" based on the radius of curvature in the axial direction and the elastic springback of the joint. This is about the same length as the 95% confidence level for the maximum displacement during a postulated SLB event. Since circumferential indications would not be expected above the top of the hardroll lower transition, the appearance of circumferential indications which could be postulated to lead to severing of the affected tube at elevation an which could be exposed to the full primary-to-secondary pressure difference would be expected to be of low probability.

7.4 Leakage Potential

Leak rates may be estimated from the tests that were performed, see References 8 and 9, and from calculations assuming various other geometry conditions, e.g., for a severed tube end which is elevated relative to the sleeve. It is to be noted that the maximum estimated primary-to-secondary differential pressure during a postulated SLB of 2560 psid assumes that the makeup system is capable of achieving that pressure regardless of primary-to-secondary leakage. Realistically, if one severed tube end displaced such that significant leakage occurred, the primary-to-secondary differential pressure would likely not increase further. Thus, while conservative, the consideration of a significant number of leaking tubes during a postulated SLB is not realistic.

If the postulated severed tube end is assumed to be displaced relative to the sleeve, the leak rates measured for full hardroll length engagement may be estimated by assuming the flow to be controlled by a friction factor. This is appropriate instead of estimating an annulus choke flow because of the interference fit between the sleeve and the tube in the hardroll region. The relationship between the flow, Q, the length of engagement, L, the differential pressure, ΔP, and the friction factor, f, would be,

$$Q = \frac{\Delta P}{fL} . \tag{7.2}$$

The value of f could be estimated from the leak test for which the length of engagement was 1". However, this is not necessary since a comparison of leak rates for different engagement lengths leads to the relation,

$$Q_2 = Q_1 \frac{L_1}{L_2}. \tag{7.3}$$

Thus, if the length of engagement is halved, the expected leak rate is doubled. This expression may provide satisfactory estimates in the range of L_2 from 1.0 to 0.25 of L_1, however, its use beyond that range would not be recommended since the $Q_2 \rightarrow \infty$ as $L_2 \rightarrow 0$, and severed tube end effects would be expected to lead to increased radial deflection at the tube end accompanied by increased leakage.

7.4.1 Normal Operation

During normal operation, the leakage from HEJ sleeved tubes with throughwall degradation extending 360° around the tube and located at the elevation of the HR lower transition would be expected to be sufficient to be detected. If the tube end does not displace, the leakage from each such joint would likely be on the order of 1 gpd or less. If the joint does displace, an increase in the leak rate would be experienced such that the plant could be shut down to address the source of the leakage.

7.4.2 Steam Line Break

For the initial evaluation of potential leak rate in the event of severing of the tubes, calculations were performed for assumed radial gaps if the tube displaced axially upward relative to the sleeve. For a radial gap of [ ][a,c], corresponding to elevating the hardroll length of the tube to correspond to the hydraulically expanded length of the sleeve, the projected leak rate was found to be ~25 gpm, References 8 and 9. If the tube displacement is limited to less than or equal to about 1.1", the ~95% confidence value for tangent point contact, the lower end of the hardrolled region of the tube would still be in contact with the upper end of the hardrolled region of the sleeve. For leakage evaluation purposes, prior calculations assumed that a gap on the order of [ ][a,c], and would thus be expected to leak at a rate of 2.5 gpm. In actuality, no gap would be expected to be present for displacements less than 1.03" and the expected leak rates would be substantially less than the estimated value of 2.5 gpm. Testing has been performed for tubes machined away at the top of the hardroll lower transition, References 8 and 9. Leak rate values under these circumstances were found to be relatively insignificant when compared to the makeup capacity of the plant hydraulic system. The maximum leakage from any single indication was estimated to be bounded between 0.01 and 0.033 gpm. These estimates may be considered to bound the leak rate if as little as ~1/4" of sleeve-to-tube hardroll interference remains. Using the maximum value as an average for all such tubes results in a total leak rate from 1000 leaking HEJ sleeved tubes of 33.0 gpm. The total IPC leak rate which might be expected from the limiting D.C. Cook or Kewaunee SG is

estimated to be less than 1 gpm. Therefore, about 1000 or more HEJ sleeved tubes with PTIs could remain in service, without expecting total leakage during a postulated SLB to exceed the 10CFR100 limit. If only the results from the three valid tests are used, i.e., 0.0, $6 \cdot 10^{-6}$, and 0.0124 gpm, respectively, four times the maximum leak rate (assuming a displacement of about 0.8") would be 0.05 gpm. Conservatively considering this maximum leak rate to apply to all sleeved tubes leads to a total leak rate for 665 HEJ sleeved tubes of 33.0 gpm. It is to be emphasized that the *average* total leak rate from the 665 sleeved tubes considered here would be expected to be significantly less than the 10CFR100 limiting leak rate.

More accurate estimates of the total leak rate could be developed using Monte Carlo simulation techniques, however, based on the conservatisms utilized for the deterministic estimates, e.g., the probability of experiencing multiple severed tube conditions was considered to be unity, such results would be expected to be significantly less than those reported herein.

7.5 Tubes Interior to Stayrod Locations

Tubes interior to stayrods have no immediate outboard neighbors. Therefore the clearance to the nearest restraint is significantly larger than for tubes with outboard neighbors, and would be expected to exceed the hop-off distance from the PTI to the top of the sleeve. Thus, the leak rate based repair boundary developed in this section is not applicable to tubes immediately interior to the stayrods.

7.6 Distribution of Indications in the Kewaunee SGs Sleeved Tubes

The distance from the bottom of the hardroll upper transition to the elevation of the indications in the Kewaunee SG tubes was measured for each indication near the elevation of the hardroll. A summary of the measured distances for each SG and for the combined SGs is provided in Table 7-3. Histogram and cumulative frequency plots of the distribution of indications in SGs "A" and "B" are provided on Figure 7-3 and Figure 7-4 respectively. The combined distribution and cumulative frequency information for both SGs is provided on Figure 7-5.

A total of 630 indications were considered in this evaluation. The average distance was found to be 1.32" with a standard deviation of 0.10". The median distance was found to be 1.32". The skew and kurtosis (normalized) were found to be 0.20 and 0.58 respectively. These last three values indicate the distribution to be relatively normal. An inspection of the plotted cumulative frequency curves indicates the distributions to be nearly symmetrical about the 50% value for the measured populations, thus supporting the judgment that the distributions are nearly normal. Hence, the probability of an indication being located within the 95% confidence bound on the potential displacement is relatively small. To be located above the average value of the potential displacement, the indication would have to be located ~4.5 standard deviations away from the mean elevation. The distribution of indications in the Kewaunee SGs confirms the expectation that very few indications would be expected to occur at elevations where significant leakage could occur during a postulated SLB.

7.7 Plant Operation Considerations

Other factors which would be expected to have a beneficial effect on the total leak rate that could be experienced are:

1) Adoption of a normal operation leakage limit of 150 gpd.

2) Implementation of nitrogen 16 (N16) monitors for monitoring SG leakage.

3) Enhanced training of operators to respond to faulted events.

7.8 Summary and Conclusions

Analyses have been performed which indicate that the total leakage that could reasonably be expected from the sleeved tubes with indications in the D.C. Cook, Kewaunee, and Point Beach 2 SGs during a postulated SLB would be small relative to the makeup capacity of the charging system. A comparison of the distance a severed tube end could be expected to move during normal operation or during a postulated SLB relative to the distance from the bottom of the HEJ hardroll upper transition to the indications in the D.C. Cook, Kewaunee, and Point Beach 2 sleeved tubes indicates that it is unlikely that any of the tubes could become disengaged from their respective sleeves if those tubes are constrained by the presence of a structurally capable outboard neighbor. For an outboard neighbor to be considered as structurally capable, it may not, if sleeved, have circumferential degradation evident above the bottom of the HEJ hardroll lower transition. Tubes which are plugged may not have been so removed from service on account of circumferential degradation. Axial degradation has no significant effect on the axial strength of active or inactive tubes, hence the presence of axial degradation alone is not considered cause to consider an outboard neighbor as not structurally viable.

This section documented the development of a geometry based repair boundary for PTIs in HEJ sleeved tubes. The resulting repair boundary is independent of the repair boundary developed in previous sections based on the structural integrity of the joint. Since the result obtained, 1.1", is the same as the structural repair boundary, it essentially demonstrates a defense in depth against the occurrence of a tube separation. The application of the repair boundary results in expected leakage during normal operation and postulated steam line break (SLB) events within limits based on 10CFR (Code of Federal Regulations), Part 100 criteria. The conclusion of the evaluation is that based on geometry considerations alone it is acceptable to leave HEJ sleeved tubes with PTIs in service that satisfy the following requirements:

1) The distance from the bottom of the HRUT to the PTI is greater than or equal to 1.1".

2) The tube is located on the interior of the tube bundle.

3) The tube is not located adjacent to and inboard of a stay rod.

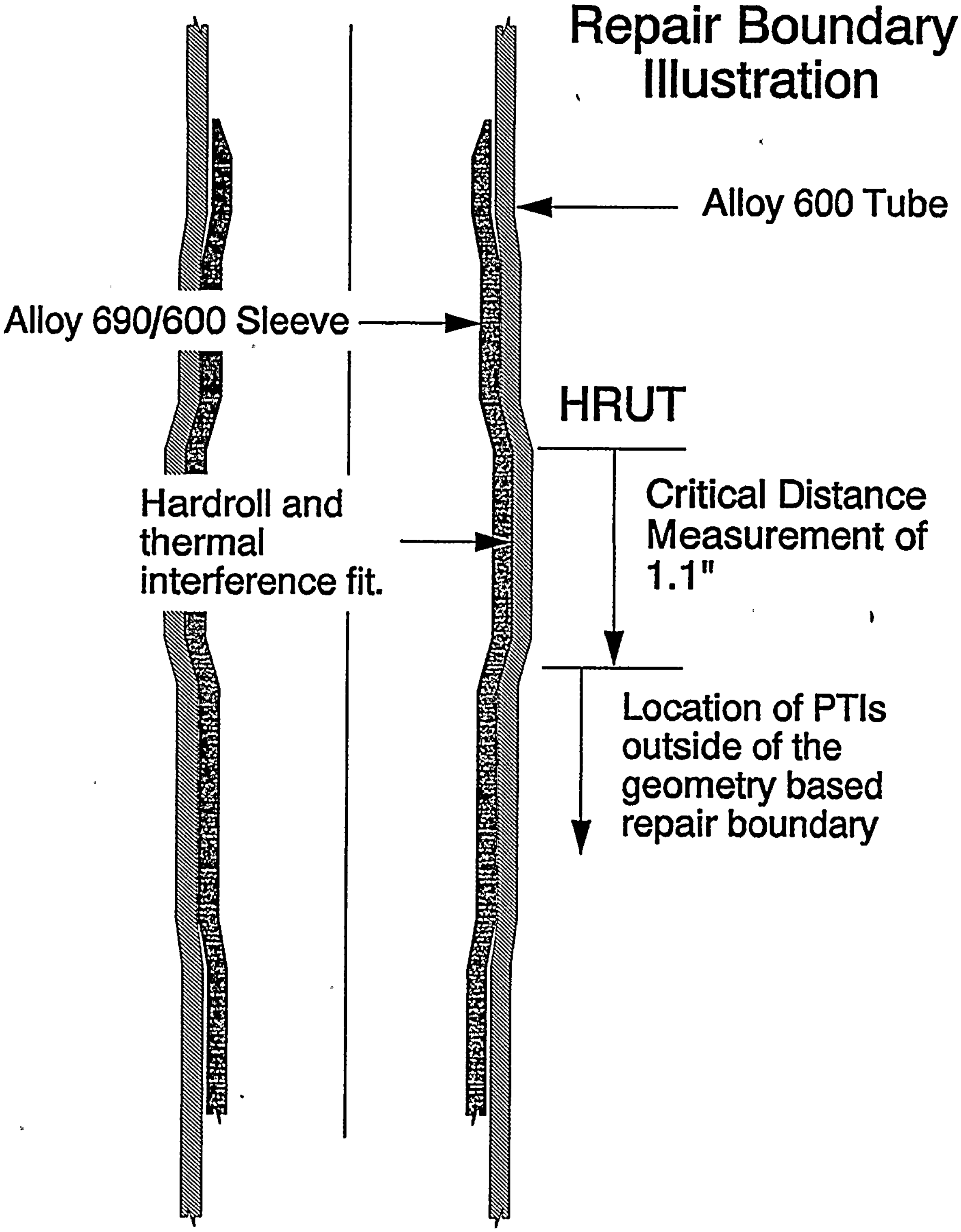
4) The outboard neighboring tube is structurally capable, i.e., it can be expected to provide restraint against upward motion of the affected tube if the affected tube is considered to be severed at or below 1.1" from the bottom of the hardroll upper transition.

For example, a review of Kewaunee Nuclear Power Plant data indicates that the first three requirements are satisfied for all sleeved tubes in the SGs. Thus, only satisfaction of the last requirement would need to be specifically demonstrated if geometry was the only basis for the repair boundary. However, the development of the geometry based boundary is secondary to the structural based boundary, so requirements 2) through 4) would not be considered to be generally applicable.

Table 7-1: Tube U-Bend Apex Clearance		
Dimension	Normal Operation	Steam Line Break
Nominal		a,c
Pressure Difference		
Average		
Standard Error		

Table 7-2: Tangent Point Clearance		
Dimension	Normal Operation	Steam Line Break
50% Confidence		a,c
60% Confidence		
90% Confidence		
95% Confidence		
99% Confidence		
99.5% Confidence		
99.9% Confidence		

Table 7-3: Distribution of the Distance of the Indications from the Bottom of the Hardroll Upper Transition			
Parameter	SG "A"	SG "B"	Both SGs
Count	426	212	638
Average	1.32	1.31	1.32
Standard Deviation	0.092	0.106	0.100
Maximum	1.63	1.75	1.75
Minimum	1.04	1.00	1.00
Median	1.32	1.30	1.32
Skew	0.01	0.52	0.20
Kurtosis	0.18	1.03	0.58



HEJ-CRIT.WPG

Figure 7-1: Illustration of the leak based criterion for HEJ sleeved tubes.

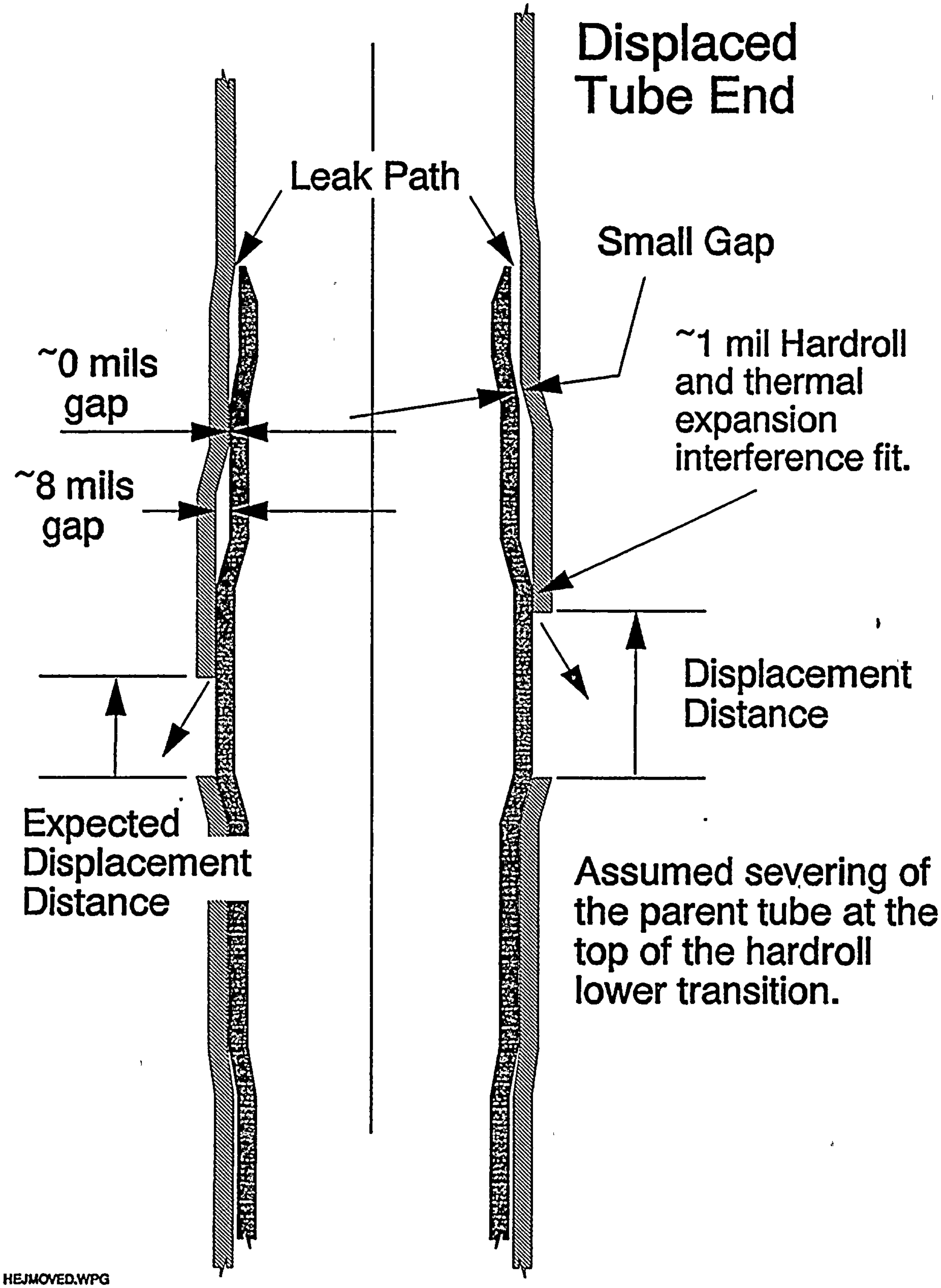


Figure 7-2: Leak path for a moved tube segment relative to the sleeve.

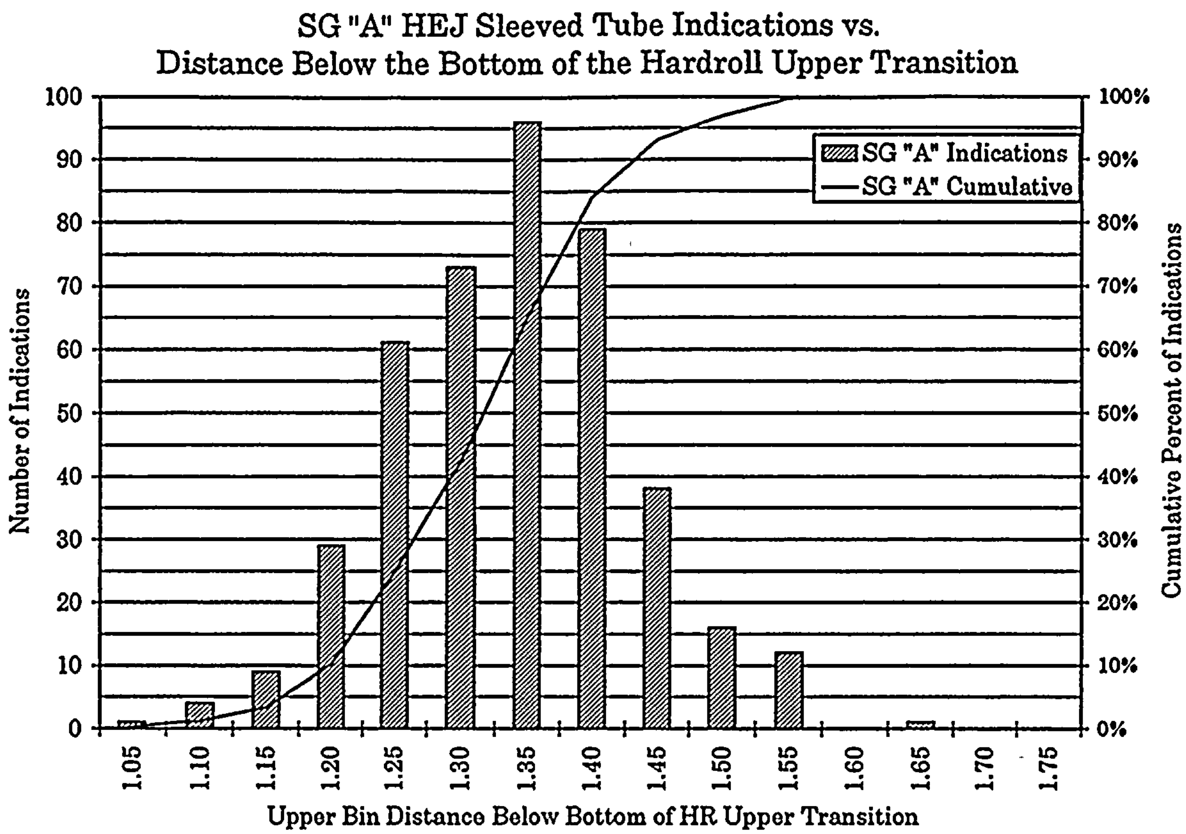


Figure 7-3

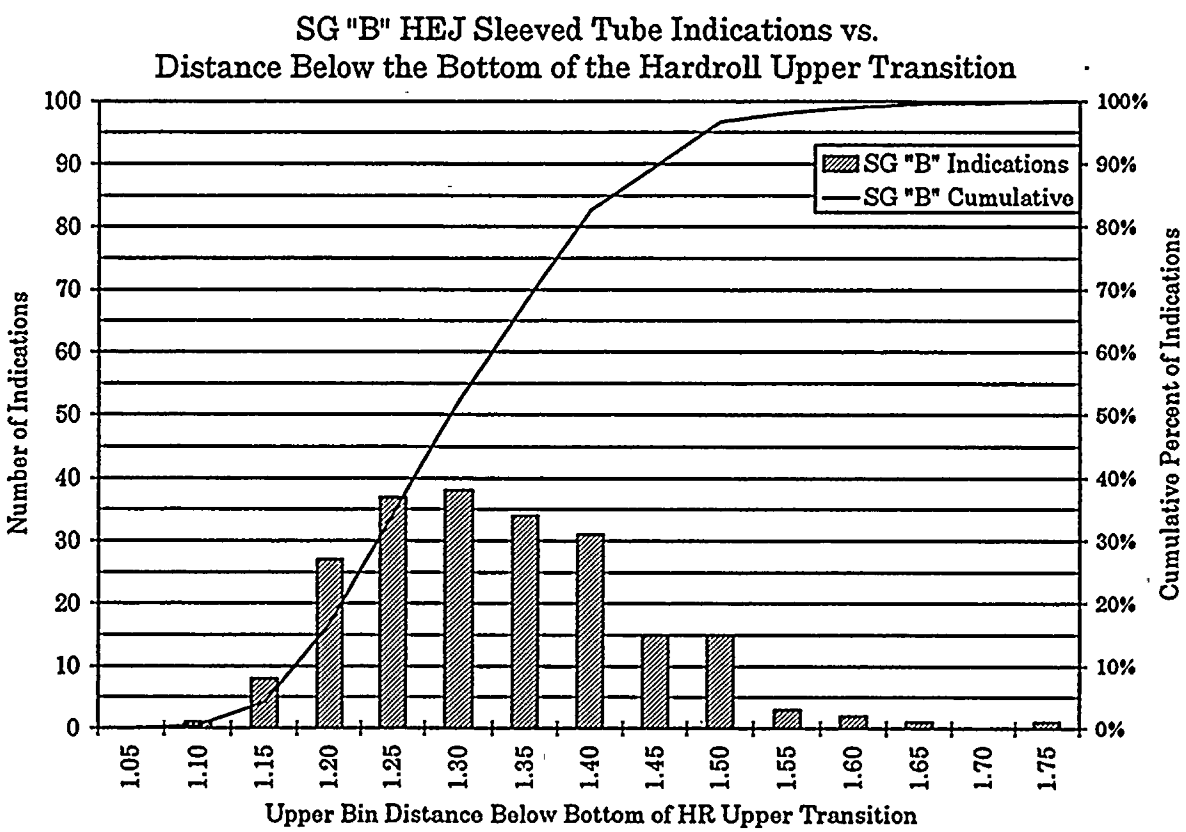


Figure 7-4

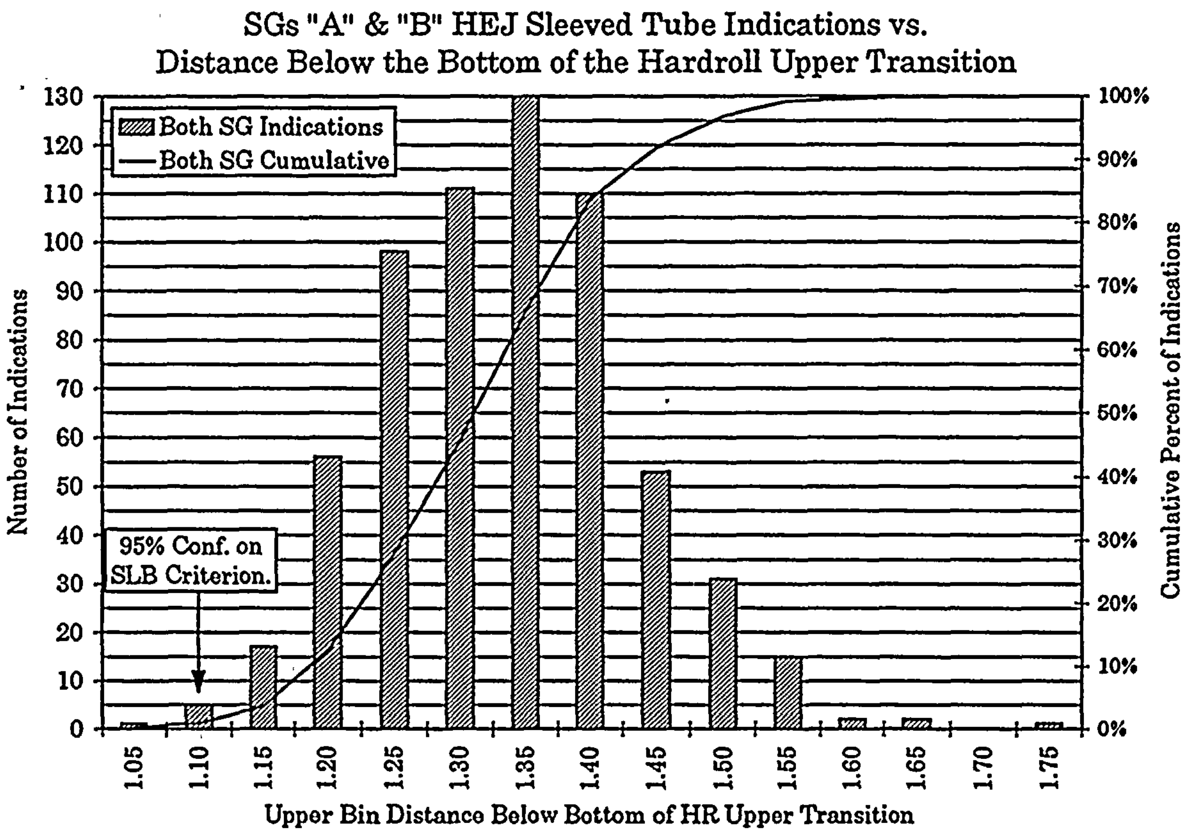

SGs "A" & "B" HEJ Sleeved Tube Indications vs.
Distance Below the Bottom of the Hardroll Upper Transition
Both SG Indications
Both SG Cumulative
95% Conf. on
SLB Criterion.
Number of Indications
Cumulative Percent of Indications
0
10
20
30
40
50
60
70
80
90
100
110
120
130
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
1.05
1.10
1.15
1.20
1.25
1.30
1.35
1.40
1.45
1.50
1.55
1.60
1.65
1.70
1.75
Upper Bin Distance Below Bottom of HR Upper Transition

Figure 7-5

8.0 Repair Boundary for Parent Tube Indications

8.1 Compliance with draft RG 1.121 Tube Integrity Criteria

To remain consistent with the licensing basis addressing structural integrity, the repair boundary must be located such that the sleeved tube meets the structural integrity (burst) requirements of RG 1.121. For the case of the repair boundary established in this document for a HEJ sleeved tube, an RCS release rate equal to those for a postulated tube burst is only possible if a circumferential separation of the parent tube occurs and is followed by upward motion of the separated end by a distance on the order of 3". Separation of the tube can only occur if the pressure end cap loads exceed the residual holding strength of the joint. Testing of prototype and field specimens has demonstrated that the residual strength of the separated joint is on the order of greater than 4000 lbs. The maximum load applied during normal operation of the most limiting plant is 724 lbs. Thus, a margin of safety relative to normal operation is on the order of 5.5 versus the RG 1.121 requirement of a margin of 3. The axial load applied during a postulated SLB is 1060 lbs. Thus, the margin of safety during postulated accident conditions is about 3.8 versus the RG 1.121 requirement of 1.43.

In order for the tube to experience leak rates on the order of those associated with a steam generator tube rupture described in the FSAR, the parent tube must experience axial motion of ~3" (for degradation in the HEJ HRLT). At this point the tube and sleeve would no longer be in close proximity and an unrestrained leak path would be produced. Reactor coolant system leak rates approaching those assumed in the FSAR could be realized. The diameter restrictions of the sleeve itself will limit the flow through the sleeve to values less than assumed in the FSAR. The nominal tube ID flow area is approximately 36% greater than the flow area based on the sleeve ID. For tube axial displacements less than ~3" and greater than ~1.5", the primary to secondary leakage is restricted by the close proximity of the tube hardrolled region and the sleeve hydraulically expanded region. For this condition, leak rates would be expected to be on the order of one third to one half of the normal makeup capacity. For axial displacements of less than ~1.5", intimate contact between the tube and sleeve is provided by the installed diameters in the rolled region. The attendant leak rate would be expected to be about an order of magnitude less than that for a displacement of 1.5" to 3". It must be stressed that the repair boundary of 1.1" below the bottom of the HRUT based on residual strength considerations would be expected to result in motion being precluded from occurring. Furthermore, the repair boundary of 1.1" below the bottom of the HRUT based on geometric constraint considerations results in there being a very low probability that such motions would occur in the unlikely event that the residual strength was not sufficient to preclude motion.

8.2 Offsite Dose Evaluation For a Postulated Main steam Line Break Event Outside of Containment but Upstream of the Main Steamline Isolation Valve

As stated in Section 3.0, the postulated SLB event is the most limiting faulted condition with regard to offsite dose potential. Following the SLB any primary-to-secondary leakage is assumed to be entirely released to the environment. Equilibrium primary and secondary side activities are calculated based on the Technical Specification limit.

NUREG-0800 is used to calculate the maximum allowable primary-to-secondary leakage limit during the event such that offsite doses remain within the licensing basis. Similar calculations have shown that the accident initiated Iodine spiking case is usually limiting. Doses are limited to 10% of the 10 CFR 100 limit of 300 Rem thyroid dose. For example, the maximum faulted loop leakage for Point Beach Unit 2 is found to be 25 gpm in the faulted loop, assuming 150 gpd leakage in each steam generator prior to the event with a maximum RCS activity level of 1.0 micro Curies per gram dose equivalent Iodine-131. For Cook Unit 1, the value has been determined to be 12.6 gpm, and was approved by the NRC as part of the Voltage Based Interim Tube Support Plate Plugging Criteria for Cook Unit 1. Each tube permitted to remain in service due to application of the criteria will be assumed to contribute to the total leakage. If the total projected leakage exceeds the calculated maximum permissible value, tubes will be repaired or removed from service so that the projected SLB leakage value is reduced below the maximum permissible limit. As an alternative to tube repair, the RCS technical specification activity level can be reduced. For Point Beach Unit 2, lowering the allowable activity level to 0.25 micro Curies per gram dose equivalent Iodine-131 supports a maximum leakage value of approximately 100 gpm.

8.3 Evaluation of Other Steam Loss Accidents

The MSLB event outside of containment would be expected to represent the most severe static loading and dynamic response condition upon the steam generator. No U.S. plant has ever experienced a double ended guillotine rupture of a main steam pipe. Plants have experienced however, random instances where a steam line relief valve or safety valve have stuck open. Of these two, the safety valve would have a greater dynamic response upon the system. This event, however, produces a limited response compared to the double ended SLB, and the plant response to this condition would be bounded by the SLB condition response.

In addition to a postulated SLB event or a spurious opening of a safety valve, the following moderate frequency accidents:

1) uncontrolled rod withdrawal from full power,
2) loss of reactor coolant flow,
3) loss of load, and

4) loss of normal feedwater

would result in higher than normal primary to secondary pressure differentials across the steam generator tubes. All of these events are rapidly occurring transients and lead to rapid closure of the steam line isolation valves and to a relatively rapid decrease of the differential pressure. Thus, the postulated SLB event presents the most severe loading to an HEJ sleeved tube with PTIs.

8.4 HEJ Inspection Requirements

A review of the current inspection criteria suggests that the HEJ parent tube be inspected using probes capable of detecting substantial axial and/or circumferential PTIs in the region of the sleeve/tube joint. As a minimum, the probes used should demonstrate the capability of detecting 40% to 60% deep EDM axial and circumferential notches.

To assist in establishing a data base for continued evaluation, indications left in service in the sleeve regions subject to repair criteria should be inspected at the subsequent refueling outage. To assure that the data will be consistent from inspection to inspection the convention of locating parent tube indications relative to the bottom of the HRUT should be used defining the location of the PTIs.

9.0 Summary of Sleeve Degradation Limit Acceptance Criteria

9.1 Structural Considerations

Based upon the information previously identified in this report, the following structural considerations are considered to be validated:

9.1.1 Crack Indications Below the Upper Hardroll Lower Transition

Any crack indication, either circumferential or axial, is allowed to remain in service if the elevation of the uppermost portion of the crack is located below 1.1" below the bottom of the HRUT.

9.1.2 Sleeved Tube with Degradation Indications with Non-Dented Tube Support Plate Intersections

For indications in the upper hardroll lower transition, circumferential crack extent is limited to 179° at BOC. A 179° BOC throughwall crack is considered representative of a 224° EOC crack. The measured RPC angle should be assumed throughwall over its entire indicated length. Circumferential indications to which this angle limit applies are limited to the lower transition region only, and do not apply to indications in the hardroll flat area or higher.

Any circumferential crack indication existing above the lower transition with a depth estimate of 40% or greater will be removed from service or repaired, consistent with current criteria.

Axial cracks are permitted to remain in service if the uppermost part of the crack is located no less than 1/2 inch below the bottom of the upper hardroll transition.

Any axially oriented crack existing less than 1/2 inch below the bottom of the upper hardroll transition will be removed from service or repaired, consistent with current criteria.

9.1.3 Dented Tubes

The HEJ repair boundary identified in this report does not rely on the resistive effects of dented tube support plate intersections to react any portion of the tube end cap load.

9.2 Leakage Assessment

For PTIs located below the HRLT, SLB leakage would be expected to be negligible and can be excluded from SLB leak rate calculations. For circumferential indications below 1.1"

below the bottom of the HRUT, but within the HRLT, SLB leakage would be expected to be limited to ~0.02 gpm per indication.

9.3 Defense In Depth and Primary to Secondary Leakage Limits

The repair boundary identified in this report results in margins which significantly exceed the burst criteria of RG 1.121 and leakage requirements relating to offsite dose evaluation. The Technical Specification normal operating primary-to-secondary leak rate limit will be lowered to 150 gpd per SG (0.1 gpm). The leak rate used in the evaluation for each plant will be selected to represent the expected leakage from an HEJ which has experienced a complete circumferential separation at the elevation of the repair boundary. This level of leakage is readily detectable by plant leakage detection systems. The available axial translation limits of the tube and the relation of these limits to leakage limits are also addressed. Section 7.0 of this report has demonstrated that the *maximum* amount of axial motion that a postulated circumferentially separated tube could be expected to experience is 1.1". Based on the distribution of indication elevations observed at Kewaunee, a postulated movement of 1.1" would still result in a length of intimate tube/sleeve contact. If the tube were postulated to move an amount on the order of, say, 2", the maximum primary to secondary leakage would be limited to about 30 gpm at SLB pressure differentials, being limited by the thin gap created between the tube ID in the hardroll region and the sleeve OD in the hydraulically expanded region. This would be an extremely unlikely event since the sleeve/tube joint would have to have insufficient residual strength and the tube would have had to have been installed at a lower extreme deviation from its nominal U-bend elevation at the same time as its outboard neighbor having been installed at an upper extreme deviation from it nominal U-bend elevation. Such a situation would not be likely to have been overlooked during fabrication, and could be expected to have resulted in contact of the tubes in the U-bend, which would have been detected during the NDE of the tubes during prior inspection outages. Finally, the prototype testing program demonstrated that the axial friction force between the postulated separated tube and sleeve increases as the amount of slippage increases further reducing the likelihood of a tube/sleeve separation.

10.0 References

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6. WCAP-11669 (Proprietary), "Zion Units 1 and 2 Steam Generator Sleeving Report (Mechanical Sleeves)," Westinghouse Electric Corporation (1987).

7. WCAP-12623 (Proprietary), "American Electric Power D. C. Cook Unit 1 Steam Generator Sleeving Report (Mechanical Sleeves)," Westinghouse Electric Corporation (1990).

8. WCAP-14157 (Proprietary), "Technical Evaluation of Hybrid Expansion Joint (HEJ) Sleeved Tubes With Indications Within the Upper Joint Zone," Westinghouse Electric Corporation, August, 1994.

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Appendix A
Review of Prior Amendment Requests
for HEJ Sleeved Tubes

1.0 Discussion/Chronology of Prior Amendment Requests

When HEJ sleeved tube PTIs were first detected at Kewaunee in the Spring of 1994, analyses and tests were performed to characterize the effect of the degradation on the strength of the joint. Since no tubes had been removed for destructive examination, it was assumed that the degradation was in the form of circumferential cracking. A meeting was held with the NRC on April 19, 1994, during the inspection outage, to discuss the non-destructive examination techniques, the results of the non-destructive examinations, the results of structural analyses and tests performed on HEJs with simulated circumferential degradation below the hardroll in the parent tube, and to propose and amendment request to allow selected HEJ sleeved tubes to remain in service. It was demonstrated HEJs with circumferential cracks below the HRLT of any extent, i.e., up to 360°, met the structural requirements of draft RG 1.121, i.e., a margin of 3 relative to burst during normal operation and a margin of 1.43 relative to burst during a postulated SLB. Leak testing results were presented that indicated that a leak rate of < 1 gpm would be expected during a postulated SLB from all of the tubes with indications if they were allowed to remain in service. Thus, it was proposed that any indications below the HRLT be allowed to remain in service. Based on a structural analysis of circumferential cracks at the top of the HRLT, it was also recommended that tubes with projected crack lengths < 240° at the end of the next cycle be allowed to remain in service. The NRC advised Wisconsin Public Service on April 20, 1994 that insufficient time was available to properly review the request for an amendment to the operating license. Therefore, the amendment request was not submitted to the NRC for approval.

In August, 1994, in preparation for a Fall outage, the Wisconsin Electric Power Company submitted an amendment request to the NRC to allow HEJ sleeved tubes to remain in service with PTIs below the hardroll. References 8 and 9 were included with that submittal in support of the request for an operating license amendment to allow selected HEJ sleeved tubes with PTIs to remain in service at Point Beach Unit 2. The technical bases of the submittal were similar to those developed for Kewaunee, i.e., RG 1.121 criteria would be met for any indications below the bottom of the HRLT, as would HEJs with indications with projected lengths of less than 226° in the HRLT. To support the angular extent criteria, additional existing data relative to the growth of crack in tubes were collated; these indicated that crack growth rates of 45° per cycle in the circumferential direction and 20% of the tube wall thickness per cycle in the radial direction could be considered as bounding. A series of requests for additional information (RAIs) were issued by the NRC which were responded to via References 11 and 12. The license amendment request was denied based on the conclusion documented in the safety evaluation report (SER), Reference 13, prepared by the office of Nuclear Reactor Regulation of the NRC.

A meeting with the NRC, initiated by Wisconsin Public Service (WPS, Kewaunee), Reference 14, was held on February 1, 1995, to verify a mutual understanding of the concerns expressed in the SER, and to discuss each of the Wisconsin Electric Power Company (WEP, Point Beach) responses to the RAIs. The conclusions reached at that meeting relative to unresolved NRC concerns were:

1. that the database employed for the potential growth calculations was insufficient for estimating the incubation time and growth rate of parent tube flaws (PTIs),

2. that the qualifications of the NDE probes used for the inspection of the parent tubes did not include a sufficient number of cracked tube specimens as opposed to the use of machined flaws in ASME NDE standards to calibrate the probes,

3. that the level of detection and the accuracy of sizing PTIs in the upper transitions of the HEJs might not be sufficient to support the application of the criteria, and,

4. that the appearance of PTIs at the lower transition(s) is indicative of a tube that is prone to developing PTIs at the upper transitions.

Thus, taken as a whole, the NRC was concerned that undetected PTIs at the upper transitions of tubes with PTIs in the lower transition(s) could grow during the operating cycle to the extent that the structural integrity of the tube would be less than that required by the RG 1.121 at the end of the operating cycle.

Another meeting between WPS and the NRC, Reference 15, was held on April 13, 1995, during the inspection outage at Kewaunee, to discuss PTIs detected using a + Point eddy current inspection probe (the previous inspection of the parent tubes was conducted using a Zetec I-coil eddy current inspection probe). Information was presented that the probe had been qualified to EPRI guidelines using both ASME standards and cracked HEJ sleeved tube specimens which had been fabricated by Westinghouse. Summary information was also presented to show that of over 930 total PTIs found at three plants, there were no instances of the simultaneous appearance of PTIs at the lower and upper transitions. It was thus argued that PTIs in the lower transitions should not be cause to remove the sleeved tube from service. However, since much of this information was developed during the outage, there was insufficient time for the NRC to conduct a thorough review of the information and tubes with PTIs within the HEJ region were removed from service.

2.0 Summary of Structural Integrity and Leak Rate Evaluations

In order to quantify the effect of the tube indications on the operating performance of HEJs with PTIs, test and analysis programs were performed, References 8 and 9, aimed at:

1) characterizing the effect of the observed indications on the axial strength of the joint, and

2) estimating the leak rate that could be expected during normal operation and under postulated SLB conditions for the case of a tube perforated below the hardroll.

Characterization of the axial strength of the joint in the event of tube degradation of the type indicated in the Kewaunee and Point Beach tubes (no indications have been determined to be present in the Cook 1 tubes at present) was explored via axial tensile (pull out) testing and hydraulic proof testing. Additional analyses results were reported in References 11 and 12. A summary of the test and analysis programs is provided in the following sections. The results are applicable to the four U.S. plants with installed HEJs. Plant operating parameters relative to structural integrity evaluations are presented in Table A-1. The largest operating primary-to-secondary differential pressure (1535 psi) occurs in the SGs at Kewaunee. The smallest differential pressure (1225 psi) occurs at Point Beach 2. The differential pressure at Cook 1 is 1453 psi.

2.1 Structural Integrity Tests

Two types of structural tests were performed, tensile strength tests and hydraulic proof tests (References 8 and 9). Prototypic HEJ test specimens, see Figure A-1, were fabricated using Alloy 600 tubing and both Alloy 600 and Alloy 690 sleeve material.[1] The initial tensile strength tests were performed on prototypic HEJ sleeved tube specimens with the lower portion of the tube completely machined away at various postulated crack elevations. For specimens where the tubes were completely removed by machining at the elevation corresponding to the bottom of the HRLT, i.e., ~1.25 inches below the bottom of the HRUT, the structural capability of the joints were approximately twice the most limiting RG 1.121 3ΔP end cap loading. For specimens where the tubes were completely removed by machining at the elevation corresponding to the approximate mid-span of the hydraulically expanded region, i.e., ~2.25" the bottom of the HRUT, the structural capability of the joints were ~3.5 to 4 times the most limiting RG 1.121 3ΔP end cap load.

A second series of tests were conducted for HEJ sleeved tubes with simulated throughwall circumferential PTIs of less than 360° arc. The results from these tests were documented in Reference 8. In these tests, the sleeves were installed in tube samples using prototypic techniques. The tubes were first slit 100% throughwall over varying arc lengths from 120° to 240° at axial locations as near to the top of the HRLT as practical. The structurally prototypic specimens were installed in a tensile testing machine and axially loaded to failure at a temperature of 600°F with no internal pressure. The specimens were configured such that the tube end was attached to the movable crosshead of the machine and the sleeve end was attached to the stationary base. Upon loading, the bending moment caused by the centroid of the remaining ligament being non-coincident with the axis of the tube, the loading axis, caused a small lateral deflection of the tube and sleeve in the direction of the slit. This small deflecting resulted in additional locking of the tube to the sleeve such that, in most cases, even

[1] The tensile tests demonstrated that the performance of Alloy 600 thermally treated sleeves (utilized in the 1983 Point Beach 2 sleeving campaign) was similar to that of Alloy 690 sleeves.

with a 240° throughwall slit, the sleeve failed in tension at about ten times the normal operation end cap load. For the specimens that did fail in the tube ligament, the failure loads were approximately twice the ultimate tensile capacity of the ligament material. Thus, the additional friction force developed at the hardroll interface of the sleeve and the tube exceeded the most limiting RG 1.121 requirement. In summary, an HEJ sleeved tube with a PTI with a non-symmetric remaining ligament(s) of about 90° has a structural integrity in excess of the most limiting RG 1.121 requirements.

The structural proof tests were performed on specimens which had been fabricated for leak testing. Following the leak tests, the sleeved tubes were machined to simulate a 360° circumferential throughwall crack at the inflection point of the hard roll. All of the samples were then pressurized to a differential pressure of 3657 psi. The pressure was then gradually increased until slipping of the joint was noted. Initial slippage of the tubes was generally detected after an increase in the pressure of about 200 to 700 psi. The maximum pressures, i.e., those achieved when the tube was ejected ftom the sleeve, were not recorded, but did approach pressures on the order of three time normal operating pressure differentials.

2.2 Structural Integrity Analyses

The structural analyses presented in References 8, 11, and 12 considered a model of the degraded tube cross-sectional area subjected to the applied loads as shown in Figure A-2. The purpose of the analyses was to support the application of an ARC which included consideration of PTIs located at the top of the HRLT. Such indications are not a subject of this report. The criterion supported by this report is that all PTIs located below a distance of 1.1" below the bottom of the HRUT can be left in service regardless of depth or circumferential extent.

It is worth noting that the analyses demonstrated that tubes with LTL material properties would meet the RG 1.121 3ΔP structural requirement if they were cracked 224° throughwall. The acceptable throughwall angle is reduced to 196° if the remaining ligament is also assumed to be cracked 50% throughwall from the ID of the tube. The model employed assumed that no friction force, e.g., due to magnetite packing or corrosion product buildup within the tube-to-tube support plate crevices, would add to the resistance to axial motion of the tube or to reduce the applied load transmitted to the tube-to-sleeve joint.

Reference 11 noted that in addition to a postulated SLB event or spurious opening of a safety valve, the following moderate frequency accidents:

1) uncontrolled rod withdrawal from full power,
2) loss of reactor coolant flow,
3) loss of load, and
4) loss of normal feedwater

would result in higher than normal primary to secondary pressure differentials across the steam generator tubes. The maximum pressure differential across the tubes that may be

experienced for steam generator loss of secondary side pressure events is 2560 psid. For items 1) through 4), the maximum pressure differential across the tubes would be expected to be less than 1800 psid. All of these events lead to closure of the steam line isolation valves and to a relatively rapid decrease of the differential pressure. Thus, the postulated SLB event presents the most severe loading to an HEJ sleeved tube with PTIs.

2.3 Leak Rate Tests and Analyses

References 8 and 9 documented the results of elevated temperature leak tests that were performed using prototypic HEJ specimens which had the tube portion machined away at the midpoint and that the bottom of the HRLT. The specimens with the tube removed at the bottom of the HRLT exhibited leak rates on the order of 0.0012 gpm, with maximum of 0.008 gpm, at SLB conditions. The specimens with the tube removed at the midpoint of the HRLT[2] exhibited a maximum leak rate of 0.016 gpm at SLB conditions, thus, also demonstrating a significant resistance to primary-to-secondary leakage. These tests suggest that the presence of a "lip" of tube material below the top of the HRLT provides sufficient leakage restriction. The proposed amendment would establish that any indications of tube degradation greater than 1.1" below the bottom of the HRUT would be acceptable for continued service, providing a "lip" of approximately 0.1", and would also provide the geometric configuration such that neither significant tube axial displacement nor significant tube leakage would be expected during a postulated SLB event.

Leak rate tests were also conducted using HEJ sleeved tube specimens with throughwall slits extending about 240° around the circumference of the tube. The slits were located at the top of the HRLT, i.e., approximately 1.0 to 1.03" below the bottom of the HRUT. The maximum leak rate at 600°F was found to be 0.015 gpm at a differential pressure of 2450 psi. Based on the observation that one of the specimens may have exhibited leakage from one of the test fittings, a bounding SLB leak rate of 0.033 gpm per indication was established for 240° throughwall slits in the hardroll lower transition.

References 8 and 9 also documented the results of elevated temperature leak tests that were performed using specimens fabricated by sectioning and removing the tube section at the top of the HRLT. Since the acceptance of PTIs at the top of the HRLT is not a subject of this report, the results are not applicable and no discussion is necessary.

2.4 Crack Growth Rate Evaluations

An assessment of the potential growth of the PTIs in both the circumferential and radial directions was provided in References 8, 11, and 12. The distribution of PTIs initially reported at Kewaunee was analyzed to determine if there was any apparent difference between the SGs. The average, minimum, and maximum circumferential extents were similar, as were the standard deviations, and it was concluded that the distributions in each SG represented samples from the same parent population. Since the phenomena had not been previously

[2] Approximately 1.12 to 1.13 inch below the bottom of the HRUT.

reported, there was no historical database that could be used to estimate growth rates. For growth in the circumferential direction, an assumption was made regarding initiation and the average growth rate was estimated to be ~35° per year. For analysis purposes, a rate of 45° per year was assumed. This was noted to be greater than a 95% confidence bound for ODSCC for observed growth at another plant that was operating at 614°F. In addition, the published data on crack growth rates of Alloy 600, of References 21, 22, 23 and 24, and Belgian data, were quoted to support the rate assumed of 45° per year as being conservatively bounding. It was also noted that the estimated rate was about three standard deviations above the mean of observed TTS data.

There also was, and still is, no directly measured data for the radial growth rate of circumferential PTIs in HEJ sleeved tubes. Reference 12 presented information radial growth information for tubes based on field observations at McGuire, Doel 4, Arkansas Nuclear One, and Maine Yankee in support of a bounding rate of 21% per year in 7/8" nominal diameter tubes. Information from PWSCC of mechanical plugs was evaluated which indicated radial growth rates on the order of ~17% to ~23% per year in 7/8" diameter tubes depending on the material activation energy. Using the tube developed rate, it was concluded that 360° PTIs with depths of 53% (Kewaunee) to 58% (Point Beach 2) at the BOC would not exceed the RG 1.121 $3\Delta P_{NOp}$ structural limit at the end of a one year cycle. Using the mechanical plug growth rates, 360° PTIs with depths of 51% (Kewaunee) to 56% (Point Beach 2) would not be expected to exceed the RG 1.121 limits at EOC. Although it has been demonstrated by field experience that the occurrence of a PTI at the HRLT or HELT does not imply the presence of another PTI at either the HRUT or the HEUT, undetected PTIs at such locations would not be likely to violate the RG 1.121 requirements at the EOC.

3.0 Summary

Prior submittals for license amendments requested approval for the implementation of multiple criteria to deal with the occurrence of PTIs as a function of the location of the PTIs in the HEJ. These are summarized in the following paragraphs.

1. For indications below the bottom of the HRLT, it was demonstrated that PTIs of any extent did not result in degradation of the joint such that the requirements of RG 1.121 would not be met at the end of an, or any, operating cycle. This was also demonstrated for indication up to the middle of the HRLT. It was further demonstrated by test that the total leak rate from all such indications would not lead to a violation of the radiological release limits during a postulated SLB event.

2. For indications at the top of the HRLT it was demonstrated that indications on the order of 2/3 of the circumference of the tube, with the remaining ligament degraded to the detection level of the NDE, could be tolerated without exceeding the requirements of RG 1.121 at the end of the operating cycle. The acceptance criteria for the beginning of the cycle length and depth of such indications were based on assumed conservative growth rates in the circumferential and radial directions. It was demonstrated by test and analysis that a significant number of throughwall PTIs could be

allowed to remain in service without expecting leak rate limits to be exceeded.

The information presented in the main section of this report resulting from the destructive examination of the Kewaunee tubes continues to support the application of a criterion based on item 1. The results from the destructive examination of the Kewaunee tubes do not support the implementation of criteria based on item 2, even though the indications were not through wall and had a residual strength in excess of RG 1.121 requirements. Since the indications extended 360° around the tube, effective circumferential growth rates of at least 50° per year were experienced as a result of the presence multiple initiation sites. However, the information obtained does not contradict the radial growth rate developed in support of item 2. Finally, the information obtained does support the detection thresholds previously considered for both the + Point and CECCO 3 probes.

Table A-1: Operating Parameters for U.S. Plants with Installed HEJs

Plant	SG	Loops	P_P (psia)	P_S (psia)	ΔP (psi)	T_{hot} (°F)	T_{cold} (°F)
Point Beach 2	44	2	2000	775	1225	596.7	541.7
Cook 1	51	4	2100	647	1453	582.0	518.0
Kewaunee	51	2	2250	715	1535	591.2	531.8
Zion 1	51	4	2250	725	1525	592.2	532.2

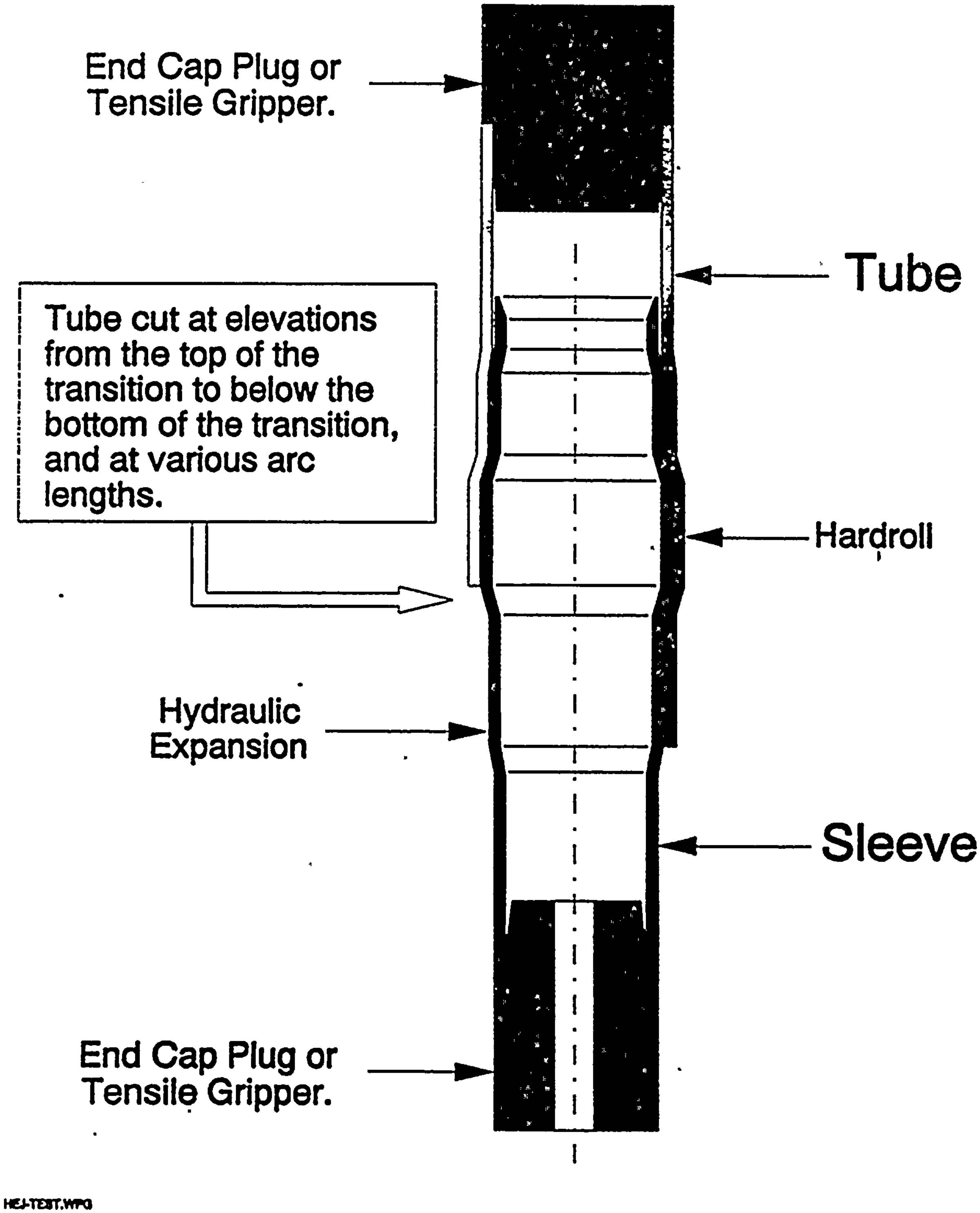
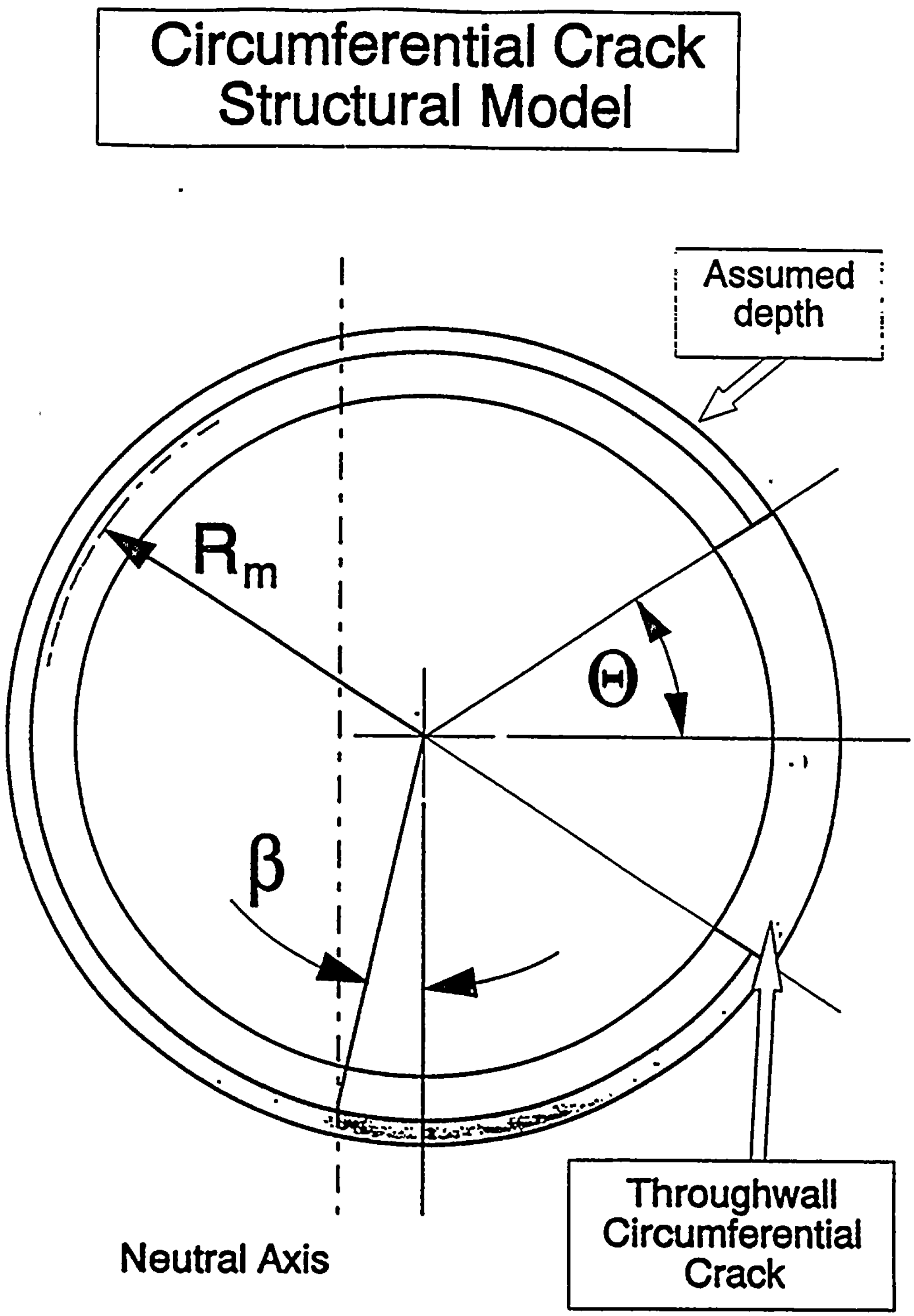


Figure A-1: HEJ specimen used for tensile testing.



CIRCSECT.WPG

Figure A-2: Structural model for a tube with a circumferential throughwall crack.

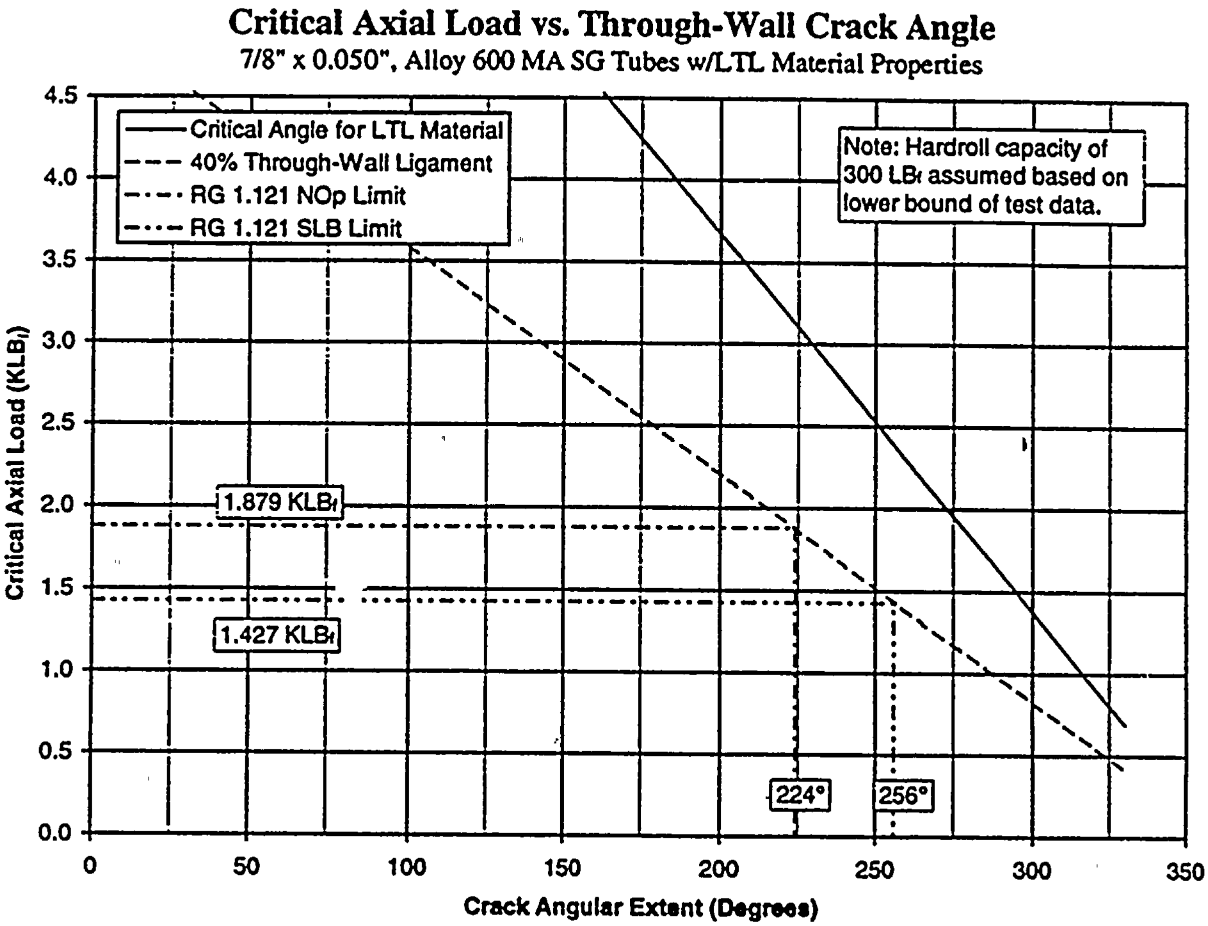

Critical Axial Load vs. Through-Wall Crack Angle
7/8" x 0.050", Alloy 600 MA SG Tubes w/LTL Material Properties
Critical Angle for LTL Material
40% Through-Wall Ligament
RG 1.121 NOp Limit
RG 1.121 SLB Limit
Note: Hardroll capacity of 300 LBf assumed based on lower bound of test data.
1.879 KLBf
1.427 KLBf
224°
256°
Critical Axial Load (KLBf)
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0
50
100
150
200
250
300
350
Crack Angular Extent (Degrees)

Figure A-3

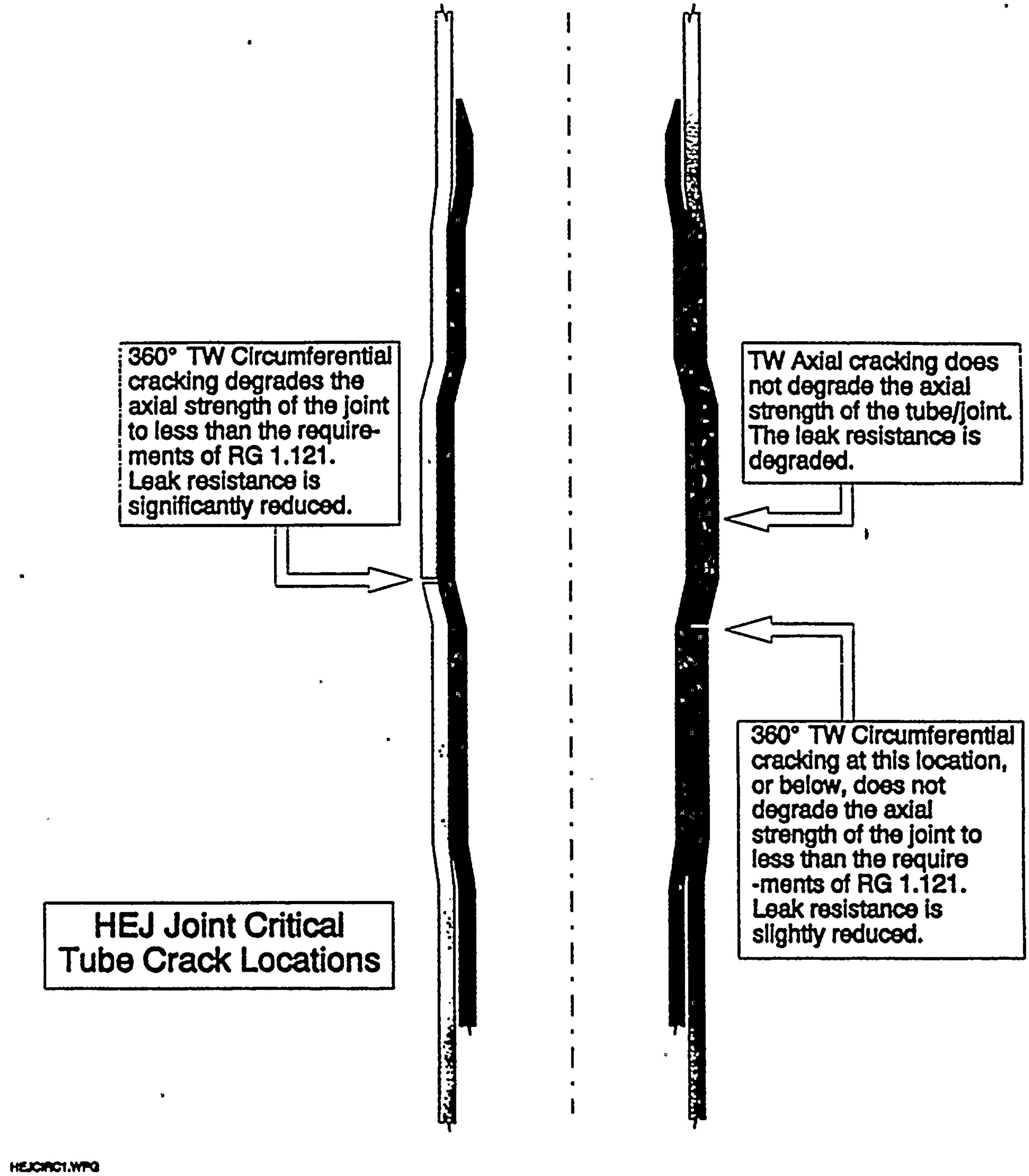


Figure A-4: Critical tube crack locations in a HEJ.

ATTACHMENT 2 TO AEP:NRC:10820

Donald C. Cook Nuclear Plant
Individual Plant Examination

Human Reliability Analysis Summary of Methodology
Changes and Example Calculations

This attachment includes a summary of the changes made in the human reliability analysis methodology and example calculations.

I. SUMMARY OF METHODOLOGY CHANGES

After a complete comparison of the original (Revision 0) AEPSC human reliability methods to the THERP [Reference 1] methods was performed, the AEPSC methods were updated to be more consistent with the THERP method and to reflect newer information. Below is a summary of the major inconsistencies identified and their resolution in the revised (Revision 1) human reliability analysis:

Human reliability action specific to sequences:

Revision 0: A simplifying assumption was utilized that an operator action, such as establishing primary feed and bleed, was independent of the accident sequence.

Revision 1: Sequence specific human error probabilities were calculated based on differences in timing, stress, dependence, and possible recoveries, using THERP.

Dependence Modeling:

Revision 0: Dependence modeling was used infrequently.

Revision 1: Prior human action failures were assessed for modeling of dependent failures of subsequent actions, both within a modeled action and between different modeled actions.

Performance shaping factors in diagnosis:

Revision 0: Training and stress performance shaping factors were utilized for the diagnosis error frequencies.

Revision 1: The EPRI methodology [Reference 2] was used for diagnosis, which is consistent with THERP.

Explicit consideration of timing:

Revision 0: For most cases, timing was only considered in a qualitative manner, with the diagnosis error rate being frequently based on the time needed to complete the action.

Revision 1: Timing was used to check if there was adequate time available to perform the action and any recovery actions. Workload was also considered as influencing the stress level.

Consistent use of second person checking:

Revision 0: Credit was generally taken for checking, to the extent needed to determine an acceptably accurate final result (i.e., once a human error failure path was found to be not the dominant path, further credits were not taken). Thus, known actions such as second person checking were inconsistently used.

Revision 1: These credits were only used when the checking actions were clearly proceduralized (e.g., checker initials required), or on a case by case basis when it could be shown that the person actually makes a habit of reviewing what the operator was doing.

Training performance shaping factors:

Revision 0: Training performance shaping factors were included for execution type errors to address the impact of improved training and procedures.

Revision 1: These generic training shaping factors were not used. Training was only considered on a case by case basis. Section 3.3 (attached) is an example of how operator training and practices were credited.

References

1. "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," A. D. Swain and H. E. Guttmann, NUREG/CR-1278, 1983.

2. "An Approach to the Analysis of Operator Actions in Probabilistic Risk Assessment," EPRI TR-100259, EPRI Project 2847-01, Final Report, June, 1992.

II. EXAMPLE CALCULATIONS

The following portions from the Donald C. Cook Nuclear Plant's Human Reliability Analysis, Revision 1, are included with this attachment:

Section 3.3	High Pressure Cold Leg Recirculation (HPR) Event Tree Level HEP Calculation
Section 3.5	Depressurization to Allow Low Pressure Injection (OLI) Event Tree Level HEP Calculation
Attachment HPR	Marked up procedure pages for Section 3.3
Attachment OLI	Marked up procedure pages for Section 3.5
Figures E-8 through E-11	HPR fault trees HPR1, HPR2, HPR3 and HPR4 (only more complex fault trees, i.e., those with AND gates, are included)

Both HPR and OLI are good examples of how dependencies were treated in the analysis. The different types considered were dependencies between personnel, steps within a human failure event, and steps in different human failure events. Both cognitive and execution error dependence were considered.

The HPR fault trees are much more detailed than the majority of the HRA fault trees due to dependence with switchover to containment spray recirculation (CSR), which is performed at the same time. These switchover actions had common cognitive errors (i.e., totally dependent), and some common execution errors. These common cognitive and execution errors were quantified as totally dependent by using the same identifiers in the corresponding fault trees.

As described in Section 3.5.6, for a Medium LOCA event, OLI is required about the same time as switchover to recirculation. As many factors influence which comes first, it was conservatively assumed that OLI precedes switchover and switchover was considered totally dependent on OLI.

For more information on the assumptions used in the analysis, see Section 3.3.3 of Attachment 1 of this submittal. Results are summarized in Tables 3.3-2 and 3.3-3 of Attachment 1 of this submittal.

3.3 HPR - HIGH PRESSURE COLD LEG RECIRCULATION

3.3.1 Application

Small LOCA (SLO) with success of auxiliary feedwater (AF4) - HPRA (JMR)
SLO with failure of auxiliary feedwater (AF4) - HPRB (JMR)

Medium LOCA (MLO) with success of auxiliary feedwater (AF4) - HPRC (JMR)

Transient with Steam Conversion Systems Available (TRA) - HPRD (JAJ)
Transient without Steam Conversion Systems Available (TRS) - HPRE (JAJ)

Large Steam Line/Feedline Break (SLB) - HPRF (JAJ)

Loss of Offsite Power (LSP) - HPRG (JAJ)

Steam Generator Tube Rupture (SGR) - HPRH (JAJ)

Station Blackout (SBO) with success of AFT, success or failure of RCC, success of AFC, XHR, CNU, RRI, and AF1, and success or failure of CSI - HPRS (JMR)
SBO with success of AFT, success or failure of RCC, success of AFC, XHR, CNU, and RRI, failure of AF1, success of PBB, and success or failure of CSI - HPRT (JMR)
SBO with success of AFT, success or failure of RCC, failure of AFC, success of XHR, CNU and PBB, and success or failure of CSI - HPRU (JMR)
SBO with failure of AFT, success of XHR, CNU, and PBB, and success or failure of CSI - HPRV (JMR)

Loss of CCW or ESW with success of RCP and RR2 - HPRW (JMR)

3.3.2 Description

High pressure cold leg recirculation is required for several top events following successful ECCS high pressure injection when RWST reaches the low level setpoint of 32%. The transfer to recirculation is required to ensure a continued source of flow is available to the RCS so that core cooling is maintained following depletion of the RWST inventory. In the HPR phase, the water that is spilled from the break collects in the lower containment, flows through course and fine mesh strainers into the recirculation sump. The CCPs and SI pumps then take suction from the recirculation sump via the residual heat removal system. During the manual switchover from the injection phase to the recirculation phase, both the RHR and SI pumps discharge line cross-tie valves are shut. This provides two separate trains of injection during the recirculation phase.

3.3.3 Success Criteria and Timing Analysis

Success of this event requires one of two SI pumps and one of two CCPs to inject to one of three intact cold legs with the pump suction supplied by one of two RHR trains operating in the recirculation mode. If this top event fails, late core damage with the RCS at high pressure is postulated to occur.

The Event Tree Notebook provides justification for the time to switchover from accident initiation and the amount of time the operator has to complete the switchover based on useable volume of the RWST for each application of this top event. A summary of these success criteria times is presented below. Refer to the Event Tree Notebook for additional information.

For medium LOCA (MLO) and small LOCA (SLO), the time from accident initiation until switchover is required would be approximately 30 minutes, assuming all safeguards pumps initially operating. This assumes containment spray is actuated early in the accident. The time to switchover would be longer if there are equipment failures or if spray actuation is delayed. Once RWST level reaches 32% and switchover is initiated, the operators will have 17 minutes to complete the switchover to high pressure recirculation before any of the safeguards pumps cavitate due to air entrainment (Reference 1).

For steam generator tube rupture (SGR) events, containment spray actuation would be expected about 30 minutes following initiation of primary bleed (See Success Criteria Notebook, Table 28). Switchover to high pressure cold leg recirculation would then be required about 30 minutes after this. This relative timing would also be expected for transient events in which bleed and feed recovery is used due to unavailability of feedwater for decay heat removal. Once RWST level reaches 32% and switchover is initiated, the operators will have 17 minutes to complete the switchover to high pressure recirculation before any of the safeguards pumps cavitate due to air entrainment. This time is the same as that for MLO and SLO since containment spray actuation is expected following initiation of bleed and feed. This timing analysis is also applicable to TRA, TRS and LSP events in which bleed and feed recovery is used due to the unavailability of feedwater for decay heat removal.

For SLB events, the time from accident initiation for a large secondary break inside containment until switchover is conservatively assumed to be approximately 30 minutes. This assumes containment spray is actuated early in the accident if the break is located inside containment. Similar to MLO and SLO, once RWST level reaches 32% and switchover is initiated, the operators will have 17 minutes to complete the switchover to high pressure recirculation before any of the safeguards pumps cavitate due to air entrainment.

For SBO events, depending on the amount of RCP seal leakage and the resulting need for containment spray injection, the time at which switchover to cold leg recirculation would be required could be as short as 30 minutes after spray and high pressure injection are actuated to several hours if spray actuation is not required. The timing requirements for completing the switchover to cold leg recirculation is 17 minutes, similar to MLO and SLO, since high pressure injection may also be actuated.

For SSW and CCW events, the timing analysis is the same as that of SBO, recirculation may be required within 30 minutes of event initiation and completion of the switchover actions within 17 minutes.

3.3.4 Procedures

Upon a small LOCA causing a reactor trip and SI actuation, the operators will enter E-0. At step 25, they will transfer to E-1, and at step 14 of E-1, they will transfer to ES-1.2.

The Emergency Operating Procedure used to perform switchover to cold leg recirculation is

ES-1.3, TRANSFER TO COLD LEG RECIRCULATION, Rev. 2

ES-1.3 is entered from:

a) E-1, LOSS OF REACTOR OR SECONDARY COOLANT, Rev. 5, Step 15, on low RWST level.

b) ECA-2.1, UNCONTROLLED DEPRESSURIZATION OF ALL STEAM GENERATORS, Rev. 4, Step 9, on low RWST level.

c) Other procedures whenever RWST level reaches the switchover setpoint.

For a small LOCA with success of AFW, entry into ES-1.3 will occur from the caution statement at the beginning of ES-1.2, and the RWST low level alarm provides cognitive recovery. This transition could also be from the foldout page for E-1 and ES-1.2, but this is conservatively not credited. Although the check for RWST level is performed in different procedures, depending on the initiating event, the action is the same for all cases. The Cue Table is applicable to all listed applications.

3.3.5 Critical and Recovery Actions

The following are the primary tasks which must be completed for satisfying the success criteria of the HPR actions:

1. Monitor for low RWST level and the need for establishing cold leg recirculation (Caution statement before ES-1.2) (cognitive)

2. Reset SI (Step 1 of ES-1.3)

3. Align West RHR for recirculation (Step 4 of ES-1.3)

4. Align CCPs and SI pumps for recirculation (Step 5 of ES-1.3)

5. Align east RHR pump for recirculation (Step 6 of ES-1.3)

See Table 3.3-1, Cue Table for HPR for identification of symptoms for establishing high pressure cold leg recirculation.

See Table 3.3-2, Subtask Analysis for HPR for identification of critical or relevant recovery actions associated with cold leg recirculation.

3.3.6 Assumptions

See sections 3.3.8, 3.3.9 and 3.3.10.

3.3.7 Significant Operator Interview Findings

1. Switchover to recirculation takes top priority above all other actions. Whenever the RWST level reaches 32%, they will stop what they are doing and immediately go to ES-1.3. The unit supervisor and RxO will not be interrupted with other tasks, and

others in the control room know to not get in the way.

2. The unit supervisor, who is reading the procedure, will watch each step performed by the RxO, and wait until completion of the step (i.e., until valves have transferred to correct position) before going on to the next step.

3. There will be at least two others in the control room who will be going through the procedure and ensuring that the steps are carried out completely (i.e., the extra US and the STA). The SS, ASS and BOPO may also be watching.

4. Whenever the operators start a pump or close a suction valve, they will watch the pump amps and discharge flow. This is second nature to the operators.

5. Most unit supervisors will actually start switchover before the RWST has reached 32%, so they have do not have to hurry, and will not have to deal with the confusion of the RHR pumps tripping on low-low RWST level. They are encouraged to start early.

3.3.8 Calculation of Cognitive Error

A cognitive model was used to address diagnosis type errors (Reference 21). Tables 3.3-3 and 3.3-4 contain the calculation of the cognitive human error probability, pc, that the operators fail to recognize the need for switchover to high pressure recirculation. Pc was calculated in Table 3.3-3 to be 3.1E-03, without recovery. The recovered value of pc was calculated in Table 3.3-4 to be 1.5E-04.

3.3.9 Calculation of Execution Error

For the calculation of execution errors, the tables from Chapter 20 of Reference 2 were used. (T20-x refers to Table 20-x of Reference 2.) The critical actions identified in Table 3.3-2 were reviewed to determine the dominant critical actions to be quantified. Critical actions are not dominant if they are recovered by other procedure steps or if they follow a mechanical failure because the human error probability would be multiplied by another human error probability or a mechanical failure probability. Attachment HPR is a copy of the relevant portion of ES-1.3, with dominant critical steps circled. The reasons why the other critical steps (identified in Table 3.3-2) are not dominant are also included.

3.3.9.1 Step 4, Align West RHR Pump for Recirculation:

4a Stop & lockout W RHR PP

Errors of Omission:

Omit step/page:

1.3E-03 (T20-7 #3, Assumption G)

Step 4 of procedure

Errors of Commission:

Select wrong control when it is dissimilar to adjacent controls:

negligible (Table 20-12, #1A (Item 1A has been added by Swain since NUREG/CR-1278))

The RHR trains are delineated, the ammeter is directly above the control, and no similar ammeters are on the West RHR panel.

4c open recirc sump to W RHR/CTS pump valve

Errors of Omission:

Omit step/page:

1.3E-03 (T20-7 #3, Assumption G)

Step 4 of procedure

Errors of Commission:

Select wrong control when it is dissimilar to adjacent controls:

negligible (Table 20-12, #1A (Item 1A has been added by Swain since NUREG/CR-1278))

This control is different from adjacent controls because it is metal and has a key in it.

Total error probability for Steps 4a & c:

1.3E-03 + 1.3E-03 = 2.6E-03

4d Start W RHR PP

Errors of Omission:

Omit step:

1.3E-03 (T20-7 #3, Assumption G)

Step 4 of procedure

Errors of Commission:

negligible, see Errors of Commission for Step 4a

3.3.9.2 Step 5, Align SI Pumps and CCPs for Recirculation

5i open SI pump suction from west RHR HX valve and
5j open SI pump suction crosstie to CCP valves

These two steps were considered as one perceptual unit. These are adjacent procedure steps and the valve controls are all right next to each other (i.e., these actions are not separated by time or location).

Errors of Omission:

Omit step/page:

1.3E-03 (T20-7 #3, Assumption G)

Step 5 of procedure

Errors of Commission:

Select wrong control on panel from array of similar appearing controls:

1.3E-03 (T20-12 #3)

All safety injection suction and discharge valves are in one area on SI control panel.

Total error probability for Step 5:

2.6E-03

3.3.9.3 Step 6, Align East RHR Pump for Recirculation:

6b Stop & lockout East RHR PP

Errors of Omission:

Omit step/page:

1.3E-03 (T20-7 #3, Assumption G)

Step 6 of procedure

Errors of Commission:

Select wrong control when it is dissimilar to adjacent controls:

negligible (Table 20-12, #1A (Item 1A has been added by Swain since NUREG/CR-1278))

The RHR trains are delineated, the ammeter is directly above the control, and no similar ammeters are on the East RHR panel.

6d   open recirc sump to East RHR/CTS pump valve

Errors of Omission:

Omit step:

1.3E-03 (T20-7 #3, Assumption G)

Step 6 of procedure

Errors of Commission:

Select wrong control when it is dissimilar to adjacent controls:

negligible   (Table 20-12, #1A (Item 1A has been added by Swain since NUREG/CR-1278))

This control is different from adjacent controls because it is metal and has a key in it.

Total error probability for Steps 6b & d:

1.3E-03 + 1.3E-03 = 2.6E-03

6e   Start East RHR PP

Errors of Omission:

Omit step:

1.3E-03 (T20-7 #3, Assumption G)

Step 6 of procedure

Errors of Commission:

negligible, see Errors of Commission for Step 6b

6f   Open CCP suction from East RHR HX valve

Errors of Omission:

Omit step:

1.3E-03 (T20-7 #3, Assumption G)

Step 6 of procedure

Errors of Commission:

Select wrong control on panel from array of similar appearing controls:

1.3E-03 (T20-12 #3)

It is clearly labeled on the boric acid charging and letdown panel. It is at the bottom left of the panel.

3.3.10 Calculation of Total Human Error Probability for Failure to Switchover to HPR

The cognitive and execution error probabilities were calculated in sections 3.3.8 and 3.3.9 to be:

pc'(HPRA) = 1.5E-04	
pe(steps 4a&c) = 2.6E-03	(without stress, dependence or recovery)
pe(step 4d) = 1.3E-03	(without stress, dependence or recovery)
pe(step 5) = 2.6E-03	(without stress, dependence or recovery)
pe(steps 6b&d) = 2.6E-03	(without stress, dependence or recovery)
pe(step 6e) = 1.3E-03	(without stress, dependence or recovery)
pe(step 6f) = 2.6E-03	(without stress, dependence or recovery)

In order for alignment of the east RHR train (step 6) to recover for an error in aligning the west train (step 4), the operators must recognize that there is not adequate flow from the west RHR pump train before aligning the high head pumps (step 5). The high head pumps are expected to fail quickly without a suction source (per operator interviews). A high level of dependence is assumed, therefore, for the operators recognizing that there is a problem with the east RHR train before they align the high head pumps in step 5. This was modelled by a high dependence failure of noticing failed step 4, so performing step 6 before step 5 (i.e., human error probability = 0.5). A high level of dependence is conservative, however, as the operator and unit supervisor will be watching pump amperes when suction sources are closed (e.g., for the high head pumps) and when the RHR pumps are started (per operator interviews). The ammeters are right above the pump controls in the control room. Also, the unit supervisor watches what the operator is doing, and waits for completion of one step before moving on to another (which can be significant, as it takes about 30 seconds for the RWST suction valves to close).

A moderate level of dependence was assumed between failure of step 4 and the initial tasks in step 6. Although steps 4 and 6 are similar, they are different procedure steps, on different pages, and unless the operators realize they failed step 4, step 5 will be performed between them. An extremely high level of stress is assigned to all step 6 actions, though, as these actions are only critical if the operators failed in step 4.

Per operator interviews, a minimum of two people will be watching the unit supervisor and operator go through the switchover using a copy of the procedure. Whenever switchover is occurring, it is top priority, and almost everything else has come to a stop. The STA does not want to get in the way, so he will be going through the procedure and watching what is going on, as well as the extra unit supervisor. The unit supervisor is not interrupted during switchover, therefore, the extra unit supervisor will be free to watch the switchover. Several more people may also be watching, but this is conservatively not credited. If it is under an hour after event initiation, the shift supervisor may still be busy with his E-plan duties. The assistant shift supervisor may be busy in his role as contingency director, and the BOPO may not be paying close enough attention to catch a mistake.

Only one recovery was given to the extra unit supervisor and STA. A low level of dependence was assumed between them and the unit supervisor and RxO because they are not interacting at all with the US and RxO; they are standing back and fulfilling a supervisory type role. This combined effort was equated to that of the shift supervisor in Table 20-4, Reference 2.

Per table 20-16, HEPs should be multiplied by two for moderately high stress for step-by-step tasks, and by 5 for extremely high stress for step-by-step tasks. Per Table 20-17, if the basic human error probability (BHEP) is greater than .01, the equations to use for low, moderate, and high dependence are: (1+19N)/20, (1+6N)/7, and (1+N)/2, respectively. Per Table 20-21, if the BHEP is less than or equal to .01, HEPs of .05, .15 and .5 should be used for low, moderate, and high dependence, respectively.

Recovery due to extra unit supervisor and STA following procedure and actions = 0.05

These parameters and assumptions are used below to determine the total human error probability for failure to switchover for high pressure recirculation under different conditions.

<u>HPRA: Switchover to high pressure recirculation upon a small LOCA and successful AFW (AF4)</u>

(CSI status is not addressed. If CSI failed, operators would have even more time to perform HPR, and it would not be required until much later into the event. The corresponding decrease in stress would be negated by the added stress the operators experience if they notice CSI has failed.)

A moderately high level of stress was assumed for steps 4 and 5. This is a procedure that is well known and practiced by the operators, and they are not concentrating on doing anything else during this procedure, as it takes top priority.

pc'(HPRA) = 1.5E-04	(HPRA-LPR-CSRHE)
pe'(steps 4a&c) = 2.6E-03 * 2 = 5.2E-03	(REC--4A&C-MHHE)
pe'(step 4d) = 1.3E-03 * 2 = 2.6E-03	(REC----4D-MHHE)
pe'(step 5) = 2.6E-03 * 2 = 5.2E-03	(REC-----5-MHHE)
pe'(steps 6b&d) = 2.6E-03 * 5 with MD	(REC--6B&D-EHHE-M)
= (1 + 6*1.3E-02)/7 = 1.5E-01	
pe'(step 6e) = 1.3E-03 * 5 = 6.5E-03	(REC----6E-EHHE)
pe'(step 6f) = 2.6E-03 * 5 = 1.3E-02	(REC----6F-EHHE)
pe'(recognize to do step 6 before step 5) = HD = 0.5	(REC-6THEN5--HE-H)
Recovery, execution errors (extra US and STA) = 0.05	(REC-US-STA--HE-L)

The total human error probability (THEP) for failing to switchover to high pressure recirculation upon a small LOCA and successful AFW (AFW) is calculated as shown in fault tree HPR1:

THEP(HPRA) = pc' + [pe'(step 4) * pe'(step 6) + pe'(step 5)] * recovery(extra US or STA)

THEP(HPRA) = 1.5E-04 + [(5.2E-03 + 2.6E-03) * (0.5 + 1.4E-01 + 6.5E-03 + 1.3E-02) + 5.2E-03] * 5.0E-02

THEP(HPRA) = 6.7E-04

HPRB: Switchover to high pressure recirculation upon a small LOCA, failure of AFW (AF4), and success of primary bleed and feed (PBF1)

(CSI status is not addressed. If CSI failed, operators would have even more time to perform HPR, and it would not be required until much later into the event. The corresponding decrease in stress would be negated by the added stress the operators experience if they notice CSI has failed.)

For this scenario, the operators will transition from Step 18 of E-0 to FR-H.1 to complete PBF. Due to adverse containment conditions, the operators will immediately go to step 18 of FR-H.1. They should still be in FR-H.1 when RWST level reaches 32%. The caution statement after step 25 of FR-H.1 will be their cue to monitor the RWST level, with cognitive recovery provided by the alarm. It is assumed that the RxO monitoring the RWST level will have a high work load, as they will be busy with PBF and subsequent actions in FR-H.1. The only change in pc' from pc'(HPRA) will be to tree b. The new end path will be l due to the high work load, which is not recovered.

pc'(HPRB) = 7.5E-04 + 3.0E-07
pc'(HPRB) = 7.5E-04 (HPRB-LPR-CSRHE)

The extremely high level of stress from primary bleed and feed is conservatively assumed to still exist. Otherwise, the actions have the same failure probabilities as HPRA.

pe'(steps 4a&c) = 2.6E-03 * 5 = 1.3E-02	(REC--4A&C-EHHE)
pe'(step 4d) = 1.3E-03 * 5 = 6.5E-03	(REC----4D-EHHE)
pe'(step 5) = 2.6E-03 * 5 = 1.3E-02	(REC-----5-EHHE)
pe'(steps 6b&d) = 2.6E-03 * 5 with MD	(REC--6B&D-EHHE-M)
= (1 + 6*1.3E-02)/7 = 1.5E-01	
pe'(step 6e) = 1.3E-03 * 5 = 6.5E-03	(REC----6E-EHHE)
pe'(step 6f) = 2.6E-03 * 5 = 1.3E-02	(REC----6F-EHHE)
pe'(recognize to do step 6 before step 5) = HD = 0.5	(REC-6THEN5--HE-H)
Recovery, execution errors (extra US and STA) = 0.05	(REC-US-STA--HE-L)

The total human error probability (THEP) for failing to switchover to high pressure recirculation upon a small LOCA, failure of AFW (AF4), and success of PBF is calculated as shown in fault tree HPR2:

THEP(HPRB) = pc' + [pe'(step 4) * pe'(step 6) + pe'(step 5)] * recovery(extra US or STA)

THEP(HPRB) = 7.5E-04 + [(1.3E-02 + 6.5E-03) * (0.5 + 1.4E-01 + 6.5E-03 + 1.3E-02) + 1.3E-02] * 5.0E-02

THEP(HPRB) = 2.0E-03

HPRC: Switchover to high pressure recirculation upon a medium LOCA and successful AFW (AF4)
(CSI status is not addressed. If CSI failed, operators would have even more time to perform HPR, and it would not be required until much later into the event. The corresponding decrease in stress would be negated by the added stress the operators experience if they notice CSI has failed.)

This is the exact same scenario as HPRA, except for the size of the LOCA. For this event, however, this difference in LOCA size is irrelevant, as the timing and flow through the procedures should be the same.

The total human error probability (THEP) for failing to switchover to high pressure recirculation upon a medium LOCA and successful AFW (AFW) is the same as HPRA:

THEP(HPRC) = THEP(HPRA) = 6.7E-04

HPRD: Switchover to high pressure recirculation after a transient with steam conversion systems available (TRA), followed by loss of auxiliary feedwater (AF1), a loss of alternate secondary cooling sources (AFW from the other Unit and main feedwater-MF1, and SG depressurization combined with condensate-OA5), and success of primary feed and bleed (PBT). In this scenario, the operator initiates a LOCA when primary feed and bleed is started. Because of this, switchover to recirculation will occur approximately 30 minutes after Containment Spray Injection actuates. Containment Spray Injection actuates a short time after the rupture disk on the primary pressure relief tank blows out. This timing is similar to the development in the small LOCA event tree (SLO) on the path where high pressure injection (HP2) succeeds and auxiliary feedwater (AF4) succeeds, leading to high pressure recirculation about a half hour later. Thus, equation HPRD equals HPRA, and fault tree HPR1 is used.

For the branch where primary bleed and feed succeeds, but containment spray injection fails, HPRD is also assigned because the development is similar to that described above, only the containment spray injection fails to actuate extending the timing.

HPRE: Switchover to high pressure recirculation after a transient with failure of steam conversion systems (TRS), followed by loss of auxiliary feedwater (AF1), and success of primary feed and bleed (PBT). In this scenario, the operator initiates a LOCA when primary feed and bleed is started. Because of this, switchover to recirculation will occur approximately 30 minutes after Containment Spray Injection actuates. Containment Spray Injection actuates a short time after the rupture disk on the primary pressure relief tank blows out. This timing is similar to the development in the small LOCA event tree (SLO) on the path where high pressure injection (HP2) succeeds and auxiliary feedwater (AF4) succeeds, leading to high pressure recirculation about a half hour later. Thus, equation HPRE equals HPRA, and fault tree HPR1 is used.

For the branch where primary bleed and feed succeeds, but containment spray injection fails, HPRE is also assigned because the development is similar to that described above, only the containment spray injection fails to actuate extending the timing.

HPRF: Switchover to high pressure recirculation after a large steam/feedwater line break (SLB), followed by successful high pressure injection (HP3) and successful isolation of the faulted SG (MS1) but loss of auxiliary feedwater (AFS), countered by success of primary feed and bleed (PBS). In this scenario, the operator initiates a LOCA when primary feed and bleed is started. Because of this, switchover to recirculation will occur approximately 30 minutes after Containment Spray Injection actuates. Containment Spray Injection actuates a short time after the rupture disk on the primary pressure relief tank blows out. This timing is similar to the development in the small LOCA event tree (SLO) on the path where high pressure injection (HP2) succeeds and auxiliary feedwater (AF4) succeeds, leading to high pressure recirculation about a half hour later. Thus, equation HPRF equals HPRA, and fault tree HPR1 is used.

For the branch where primary bleed and feed succeeds, but containment spray injection fails, HPRF is also assigned because the development is similar to that described above, only the containment spray injection fails to actuate extending the timing.

HPRG: Switchover to high pressure recirculation after a transient loss of offsite power (LSP), followed by loss of auxiliary feedwater (AF1), and success of primary feed and bleed (PBL). In this scenario, the operator initiates a LOCA when primary feed and bleed is started. Because of this, switchover to recirculation will occur approximately 30 minutes after Containment Spray Injection actuates. Containment Spray Injection actuates a short time after the rupture disk on the primary pressure relief tank blows out. This timing is similar to the development in the small LOCA event tree (SLO) on the path where high pressure injection (HP2) succeeds and auxiliary feedwater (AF4) succeeds, leading to high pressure recirculation about a half hour later. However, there may be one train equipment unavailable depending on the diesel generator (DG) response. If two diesel generators succeed, then HPR equals HPRA. If only one diesel generator succeeds, then HPR equals HPRA (in timing) but with only one train available. Although the case for the two DG success is more likely (~95%), the case of success of only one DG (~5%) leads to more restrictive modeling and has conservatively been applied. Thus, equation HPRG equals HPRA Steps 4 and 5, as calculated in fault tree HPR4.

For the branch where primary bleed and feed succeeds, but containment spray injection fails, HPRG is also assigned because the development is similar to that described above, only the containment spray injection fails to actuate extending the timing.

HPRH: Switchover to high pressure recirculation after a steam generator tube rupture (SGR), followed by loss of all auxiliary feedwater (AF2 and AF3), and success of primary feed and bleed (PBG). In this scenario, the operator initiates a LOCA inside of containment when primary feed and bleed is started. Because of this, switchover to recirculation will occur approximately 30 minutes after Containment Spray Injection actuates. Containment Spray Injection actuates a short time after the rupture disk on the primary pressure relief tank blows out. This timing is similar to the development in the small LOCA event tree (SLO) on the path where high pressure injection (HP2) succeeds and auxiliary feedwater (AF4) succeeds, leading to high pressure recirculation about a half hour later. Thus, HPRH equals HPRA, and fault tree HPR1 is used.

HPRS: Switchover to high pressure recirculation upon a SBO and success of AFT, success or failure of RCC, success of AFC, XHR, CNU, RRI, and AF1, and success or failure of CSI

Dependency upon CSI failure is not evaluated, because THEP for CSI is mostly due to errors of omission, which are independent for steps on different pages, with the remainder due to cognitive failures. If the operators failed to actuate CSI, switchover to recirculation is not necessary for 1.5 hours after this CSI failure. In this time, there are no other system failures. This amount of time, with no other major operator tasks, negates any cognitive dependency.

Early failure of RCS cooldown (RCC) is not addressed separately, as this action was performed several hours earlier (long before power restoration), errors of commission were due to the AEO (who will not be involved in HPR), and there have been numerous successes since this time. This early failure should not cause a higher level of stress at this time. RCC failure just mandated earlier power restoration, which was successful.

Per the Event Tree Notebook (Reference 1), with the containment spray and high head ECCS pumps injecting, there is 17 minutes available for switchover, and switchover will not be required until at least 30 minutes following completion RRI and CSI.

For this scenario, everything has been successful following power restoration, and at least 30 minutes have elapsed since operators finished RRI and CSI. Power has been back for an hour, and things are under control. The operators will transfer to E-1 (LOSS OF REACTOR OR SECONDARY COOLANT) at the end of ECA-0.2 (i.e., step 14).

The cue for the operators to monitor RWST level will be Step 15 of E-1. A low work load can be assumed at this time and recovery with the alarm can also be credited. This results in a value for pc' equal to that for HPRA. (The end state for tree e is all that changes (from b to c), but the value remains the same (3.0E-03).)

pc'(HPRS) = pc'(HPRA)

As things are under control, recovery due to the extra US/STA can be credited.

Therefore, the total human error probability for failing to switchover to high pressure recirculation upon a SBO and success of AFT, success or failure of RCC, success of AFC, XHR, CNU, RRI, and AF1, and success or failure of CSI is the same as that from HPRA.

THEP(HPRS) = THEP(HPRA)

Fault tree HPR1 is used.

HPRT: Switchover to high pressure recirculation upon a SBO and success of AFT, success or failure of RCC, success of AFC, XHR, CNU, and RRI, failure of AF1, success of PBB, and success or failure of CSI

Although the event tree displays PBB occurring before CSI, the operators must complete CSI before they transfer to any FRPs (i.e., PBF). Therefore, as these paths include success of PBF, there is no dependence to consider.

Failure of the containment spray system is not addressed separately. If CTS failed, operators would have even more time to perform HPR, and it would not be required until much later into the event (i.e., 2 hours following power recovery). The corresponding decrease in stress would be negated by the added stress the operators experience if they notice CTS has failed.

Early failure of RCS cooldown (RCC) is not addressed separately, as this action was performed several hours earlier (long before power restoration), errors of commission were due to the AEO (who will not be involved in HPR), and there have been numerous successes since this time. This early failure should not cause a higher level of stress at this time. RCC failure just mandated earlier power restoration, which was successful.

For this scenario, the operators will transition to FR-H.1 following completion of Step 10 of ECA-0.2. For hydrogen control, the operators may transfer to FR-Z.1 (per caution statement before step 27 of FR-H.1) and then return to FR-H.1. Eventually, the operators will leave FR-H.1 to transfer E-1 or to switchover to recirculation (ES-1.3). The caution statement in FR-H.1 (before step 26) should be their cue to monitor RWST level, with cognitive recovery provided by the alarm. It is assumed that the operator monitoring RWST level will have a high work load, as they will be busy with FR-H.1 and FR-Z.1. This results in a pc' equal to that for HPRB:

pc'(HPRT) = pc'(HPRB)

The extremely high level of stress from primary bleed and feed is conservatively assumed to still exist.

Therefore, the THEP for failing to switchover to high pressure recirculation upon a SBO and success of AFT, success or failure of RCC, success of AFC, XHR, CNU, and RRI, and failure of AF1, success of PBB, and success or failure of CSI is the same as HPRB.

THEP(HPRT) = THEP(HPRB)

Fault tree HPR2 is used.

<u>HPRU: Switchover to high pressure recirculation upon a SBO, success of AFT, success or failure of RCC, failure of AFC, success of XHR and CNU, success of PBB, and success or failure of CSI</u>

See writeup for HPRT. Fault tree HPR2 is used.

This is the same scenario as described in HPRT. AFW has been lost (worse case scenario) for a couple hours before power recovery, and PBB must be initiated right after completion of CSI (i.e., step 10 of ECA-0.2).

Early failure of RCS cooldown (RCC) is not addressed separately, as this action was performed several hours earlier (long before power restoration), errors of commission were due to the AEO (who will not be involved in HPR), and there have been numerous successes since this time. This early failure should not cause a higher level of stress at this time. RCC failure just mandated earlier power restoration, which was successful.

HPRV: Switchover to high pressure recirculation upon a SBO, failure of AFT, success of XHR and CNU, success of PBB, and success or failure of CSI

Although the event tree displays PBB occurring before CSI, the operators must complete CSI before they transfer to any FRPs (i.e., PBF). Therefore, as this path includes success of PBF, there is no dependence to consider.

Failure of the containment spray system is not addressed separately. If CTS failed, operators would have even more time to perform HPR, and it would not be required until much later into the event (i.e., 2 hours following power recovery). The corresponding decrease in stress would be negated by the added stress the operators experience if they notice CTS has failed.

An extemely high level of stress is assumed, as a blackout with failure of the TDAFP is a severe incident for the operators, and switchover is required fairly early in the accident (about 2 hours from loss of power). (This level of stress is also assumed because it follows PBB.) As described in HPRT, a high work load is assumed for the RxO for calculation of pc'.

Therefore, the THEP for failing to switchover to high pressure recirculation upon a SBO, failure of AFT, success of XHR and CNU, success of PBB, and success or failure of CSI is the same as HPRT.

THEP(HPRV) = THEP(HPRT) = THEP(HPRB)

Fault tree HPR2 is used.

HPRW: Switchover to high pressure recirculation upon a loss of CCW or ESW and success of RCP and RR2

(CSI status is not addressed. If CSI failed, operators would have even more time to perform HPR, and it would not be required until much later into the event. The corresponding decrease in stress would be negated by the added stress the operators experience if they notice CSI has failed.)

HPR will not be required until very late into the event. Since the RCPs were tripped, seal failure is not actually expected until an hour or two into the event (see RCP, Section 3.25.2), at which time the containment sprays will be actuated. With both containment spray pumps operating, it takes at least 35 more minutes to reach the RWST low level. A charging pump is started (i.e., RR2A) within 30 minutes of the restoration of CCW/ESW. As a result, HPR is expected after a charging pump has been started in RR2A.

At this point, things are well under control. The small LOCA through the seals is under control and CCW/ESW has been restored. A low work load is considered for the operators by the time HPR is needed. The operators will probably still be in OHP 4022.016.004 when HPR is required, since they will not leave it until after the RCS is cooled and depressurized enough to start RHR. There is not a procedure step to warn the operators to monitor RWST level, but the operators know to monitor this. Only cognitive tree b applies (data not attended to) to this situation. End path l from tree b results in a cognitive value of 7.5E-04. No recovery is applied to this value. (Note: the path for high work load was conservatively followed, so this cognitive failure probability can be used for other scenarios.)

pc(HPRW) = 7.5E-04 (HPRW-CSR-COGHE)

It is assumed that only one train of CCW/ESW has been restored, so HPR recovery with the second train is not credible. The operators will go to Attachment A or B of ES-1.3 via step 2 or 3, since both trains of RHR/CCW are not available. The steps in these attachments are similar to the main procedure, except they will align the high head pumps to the one available train of RHR. The critical actions are still the same, with only the step numbers being different. Therefore, for simplicity, the same identifiers are used as before. (Steps 2 and 3 do not need to be evaluated because the operators would be well aware that both trains are not available, and an EOM of step 2 would be recovered by step 3 (as they are on different pages).) Due to the low work load and since things are under control, recovery with the extra US or STA is warranted.

pc(HPRW) = 7.5E-04	(HPRW-CSR-COGHE)
pe'(steps 4a&c) = 2.6E-03 * 2 = 5.2E-03	(REC--4A&C-MHHE)
pe'(step 4d) = 1.3E-03 * 2 = 2.6E-03	(REC----4D-MHHE)
pe'(step 5) = 2.6E-03 * 2 = 5.2E-03	(REC-----5-MHHE)
Recovery, execution errors (extra US and STA) = 0.05	(REC-US-STA--HE-L)

The total human error probability for failing to switchover to high pressure recirculation upon a loss of CCW or ESW and success of RCP and RR2 is calculated as shown in fault tree HPR3:

THEP(HPRW) = pc' + [pe'(step 4) + pe'(step 5)] * recovery(extra US or STA)

THEP(HPRW) = 7.5E-04 + [(5.2E-03 + 2.6E-03) + 5.2E-03] * 5.0E-02

THEP(HPRW) = 1.4E-03

3.3.11 HPR Fault Trees Summary

The basic events and cutsets (with support system failures (i.e., SUBs) set equal to 1.0E-03) for the HPR fault trees are listed below.

Fault tree HPR1
(used for HPRA, HPRC, HPRD, HPRE, HPRF, HPRH, HPRS)

```
VER 1.6
 hpr1.cut                                                        Ver. 1.71  7/25/95    9:07:40
  10     11  1.670E-03  0.000E+00  1.000E-09
               1  HPRA-LPR-CSRHE        1.5000E-04      0.0000E+00
               2  REC-US-STA--HE-L      5.0000E-02      0.0000E+00
               3  REC--4A&C-MHHE        5.2000E-03      0.0000E+00
               4  REC----4D-MHHE        2.6000E-03      0.0000E+00
               5  REC-----5-MHHE        5.2000E-03      0.0000E+00
               6  REC-6THEN5--HE-H      5.0000E-01      0.0000E+00
               7  REC--6B&D-EHHE-M      1.5000E-01      0.0000E+00
               8  REC----6E-EHHE        6.5000E-03      0.0000E+00
               9  REC----6F-EHHE        1.3000E-02      0.0000E+00
              10  SUB-HPR               1.0000E-03      0.0000E+00
               1.      1.00E-03     1   SUB-HPR
               2.      2.60E-04     2   REC-US-STA--HE-L    REC-----5-MHHE
               3.      1.50E-04     1   HPRA-LPR-CSRHE
               4.      1.30E-04     3   REC-US-STA--HE-L    REC--4A&C-MHHE      REC-6THEN5--HE-H
               5.      6.50E-05     3   REC-US-STA--HE-L    REC----4D-MHHE      REC-6THEN5--HE-H
               6.      3.90E-05     3   REC-US-STA--HE-L    REC--4A&C-MHHE      REC--6B&D-EHHE-M
               7.      1.95E-05     3   REC-US-STA--HE-L    REC----4D-MHHE      REC--6B&D-EHHE-M
               8.      3.38E-06     3   REC-US-STA--HE-L    REC--4A&C-MHHE      REC----6F-EHHE
               9.      1.69E-06     3   REC-US-STA--HE-L    REC----4D-MHHE      REC----6F-EHHE
              10.      1.69E-06     3   REC-US-STA--HE-L    REC--4A&C-MHHE      REC----6E-EHHE
              11.      8.45E-07     3   REC-US-STA--HE-L    REC----4D-MHHE      REC----6E-EHHE
```

Fault tree HPR2
used for HPRB, HPRT, HPRU, HPRV

```
VER 1.6
 hpr2.cut                                                        Ver. 1.71  7/25/95    9:07:41

  10     11  3.049E-03  0.000E+00  1.000E-09
               1  HPRB-LPR-CSRHE        7.5000E-04      0.0000E+00
               2  REC-US-STA--HE-L      5.0000E-02      0.0000E+00
               3  REC--4A&C-EHHE        1.3000E-02      0.0000E+00
               4  REC----4D-EHHE        6.5000E-03      0.0000E+00
               5  REC-----5-EHHE        1.3000E-02      0.0000E+00
               6  REC-6THEN5--HE-H      5.0000E-01      0.0000E+00
               7  REC--6B&D-EHHE-M      1.5000E-01      0.0000E+00
               8  REC----6E-EHHE        6.5000E-03      0.0000E+00
               9  REC----6F-EHHE        1.3000E-02      0.0000E+00
              10  SUB-HPR               1.0000E-03      0.0000E+00
               1.      1.00E-03     1   SUB-HPR
               2.      7.50E-04     1   HPRB-LPR-CSRHE
               3.      6.50E-04     2   REC-US-STA--HE-L    REC-----5-EHHE
               4.      3.25E-04     3   REC-US-STA--HE-L    REC--4A&C-EHHE      REC-6THEN5--HE-H
               5.      1.63E-04     3   REC-US-STA--HE-L    REC----4D-EHHE      REC-6THEN5--HE-H
               6.      9.75E-05     3   REC-US-STA--HE-L    REC--4A&C-EHHE      REC--6B&D-EHHE-M
               7.      4.88E-05     3   REC-US-STA--HE-L    REC----4D-EHHE      REC--6B&D-EHHE-M
               8.      8.45E-06     3   REC-US-STA--HE-L    REC--4A&C-EHHE      REC----6F-EHHE
               9.      4.23E-06     3   REC-US-STA--HE-L    REC----4D-EHHE      REC----6F-EHHE
              10.      4.23E-06     3   REC-US-STA--HE-L    REC--4A&C-EHHE      REC----6E-EHHE
              11.      2.11E-06     3   REC-US-STA--HE-L    REC----4D-EHHE      REC----6E-EHHE
```

Fault tree HPR3
used for HPRW

```
VER 1.6
 hpr3.cut                                                  Ver. 1.71  7/25/95   9:07:41

   6      5  2.398E-03  0.000E+00  1.000E-09
                1  SUB-HPR               1.0000E-03    0.0000E+00
                2  HPRW-CSR-COGHE        7.5000E-04    0.0000E+00
                3  REC-US-STA--HE-L      5.0000E-02    0.0000E+00
                4  REC--4A&C-MHHE        5.2000E-03    0.0000E+00
                5  REC----4D-MHHE        2.6000E-03    0.0000E+00
                6  REC-----5-MHHE        5.2000E-03    0.0000E+00
                1.     1.00E-03    1    SUB-HPR
                2.     7.50E-04    1    HPRW-CSR-COGHE
                3.     2.60E-04    2    REC-US-STA--HE-L    REC-----5-MHHE
                4.     2.60E-04    2    REC-US-STA--HE-L    REC--4A&C-MHHE
                5.     1.30E-04    2    REC-US-STA--HE-L    REC----4D-MHHE
```

Fault tree HPR4
used for HPRG

```
VER 1.6
 hpr4.cut                                                  Ver. 1.71  7/25/95   9:07:42

   6      5  1.799E-03  0.000E+00  1.000E-09
                1  SUB-HPR               1.0000E-03    0.0000E+00
                2  HPRA-LPR-CSRHE        1.5000E-04    0.0000E+00
                3  REC-US-STA--HE-L      5.0000E-02    0.0000E+00
                4  REC--4A&C-MHHE        5.2000E-03    0.0000E+00
                5  REC----4D-MHHE        2.6000E-03    0.0000E+00
                6  REC-----5-MHHE        5.2000E-03    0.0000E+00
                1.     1.00E-03    1    SUB-HPR
                2.     2.60E-04    2    REC-US-STA--HE-L    REC-----5-MHHE
                3.     2.60E-04    2    REC-US-STA--HE-L    REC--4A&C-MHHE
                4.     1.50E-04    1    HPRA-LPR-CSRHE
                5.     1.30E-04    2    REC-US-STA--HE-L    REC----4D-MHHE
```

TABLE 3.3-1 - CUE TABLE FOR HPR (High Pressure Cold Leg Recirculation) - SLO			
DIAGNOSIS	**CUE**	**SUCCESS CRITERIA**	**LOCATION**
Respond to RWST low level alarm	Alarm annunciator light	Respond to 1 of 1 alarm	Control room - SPY panel
Monitor RWST level	RWST level < 32%	Recognize symptoms requiring transfer to cold leg recirculation	Control room - SPY panel and BA panel

TABLE 3.3-2 - SUBTASK ANALYSIS FOR HPR (High Pressure Cold Leg Recirculation) - MLO, SLO, SGR, TRA, TRS, SLB, LSP, SBO, SSW, CCW

PROCEDURE		ACTION	INDICATION/ FEEDBACK	LOCATION	POTENTIAL ERRORS
NUMBER	STEP				
EOP ES-1.3, Rev. 2	1	Reset SI	SI status	Control room	Omit action Select wrong control for SI reset button
EOP ES-1.3, Rev. 2	4a	Stop 1 of 1 west RHR pump	Pump status	Control room	Omit action Select wrong controls for west RHR pump
EOP ES-1.3, Rev. 2	4b	Close 1 of 1 west RHR pump suction valve (1-IMO-320) Close 1 of 1 west RHR pump discharge crosstie valve (1-IMO-324)	Valve position	Control room	Omit actions Select wrong valve controls
EOP ES-1.3, Rev. 2	4c	Open 1 of 1 recirc sump valve to west RHR pump	Valve position	Control room	Omit action Select wrong controls for recirc sump valve

TABLE 3.3-2 - SUBTASK ANALYSIS FOR HPR (High Pressure Cold Leg Recirculation) - MLO, SLO, SGR, TRA, TRS, SLB, LSP, SBO, SSW, CCW

PROCEDURE		ACTION	INDICATION/ FEEDBACK	LOCATION	POTENTIAL ERRORS
NUMBER	STEP				
EOP ES-1.3, Rev. 2	4d	Start 1 of 1 west RHR pump	Pump status	Control room	Omit action Select wrong controls for west RHR pump
EOP ES-1.3, Rev. 2	5a, c	Reset and close 2 of 2 CCP miniflow valves	Valve switches	Control room	Omit actions Select wrong controls for CCP miniflow valves
EOP ES-1.3, Rev. 2	5d	Verify 2 of 2 North SI pump isolation valves open (1-ICM-260, 1-IMO-316)	Valve switches	Control room	Omit actions Check wrong status lights
EOP ES-1.3, Rev. 2	5e	Verify 2 of 2 south SI pump isolation valves open (1-ICM-265, 1-IMO-326)	Valve switches	Control room	Omit actions Check wrong status lights
EOP ES-1.3, Rev. 2	5f	Close 2 of 2 SI pump discharge crosstie valves (1-IMO-270, 1-IMO-275)	Pump status	Control room	Omit action Select wrong controls for crosstie valves

TABLE 3.3-2 - SUBTASK ANALYSIS FOR HPR (High Pressure Cold Leg Recirculation) - MLO, SLO, SGR, TRA, TRS, SLB, LSP, SBO, SSW, CCW

PROCEDURE		ACTION	INDICATION/ FEEDBACK	LOCATION	POTENTIAL ERRORS
NUMBER	STEP				
EOP ES-1.3, Rev. 2	5h	Close 2 of 2 SI pump recirculation valves to RWST (1-IMO-262, 1-IMO-263)	Valve switches	Control room	Omit actions
					Select wrong controls for SI pump recirc valves
EOP ES-1.3, Rev. 2	5i	Open 1 of 1 SI pump suction valve from west RHR Hx (1-IMO-350)	Valve switches	Control room	Omit actions
					Select wrong controls for SI pump suction valve
EOP ES-1.3, Rev. 2	5j	Open 2 of 2 SI pump suction crosstie valves to CCP (1-IMO-361, 1-IMO-362)	Valve switches	Control room	Omit actions
					Select wrong controls for SI pump suction valves
EOP ES-1.3, Rev. 2	5l	Close 1 of 1 SI pump suction valve from RWST (1-IMO-261)	Valve switch	Control room	Omit action
					Select wrong controls for SI pump suction valve

TABLE 3.3-2 - SUBTASK ANALYSIS FOR HPR (High Pressure Cold Leg Recirculation) - MLO, SLO, SGR, TRA, TRS, SLB, LSP, SBO, SSW, CCW					
PROCEDURE		ACTION	INDICATION/ FEEDBACK	LOCATION	POTENTIAL ERRORS
NUMBER	STEP				
EOP ES-1.3, Rev. 2	5m	Close 2 of 2 CCP suction valves from RWST (1-IMO-910, 1-IMO-911)	Valve switches	Control room	Omit 1 of 2 actions
					Select wrong controls for CCP suction valves
EOP ES-1.3, Rev. 2	5n	Verify 1 of 2 CCPs running in recirc mode	Pump status	Control room	Omit 2 of 2 actions
					Select wrong controls for CCPs
EOP ES-1.3, Rev. 2	5o	Verify 1 of 2 SI pumps running in recirc mode	Pump status	Control room	Omit 2 of 2 actions
					Select wrong controls for SI pump
EOP ES-1.3, Rev. 2	6b	Stop 1 of 1 east RHR pump	Pump status	Control room	Omit action
					Select wrong controls for east RHR pump

TABLE 3.3-2 - SUBTASK ANALYSIS FOR HPR (High Pressure Cold Leg Recirculation) - MLO, SLO, SGR, TRA, TRS, SLB, LSP, SBO, SSW, CCW

PROCEDURE NUMBER	PROCEDURE STEP	ACTION	INDICATION/ FEEDBACK	LOCATION	POTENTIAL ERRORS
EOP ES-1.3, Rev. 2	6c	Close 1 of 1 east RHR pump suction valve (1-IMO-310) Close 1 of 1 east RHR pump discharge crosstie valve (1-IMO-314)	Valve position	Control room	Omit actions Select wrong valve controls
EOP ES-1.3, Rev. 2	6d	Open 1 of 1 recirc sump valve to east RHR/CTS pump (1-ICM-305)	Valve position	Control room	Omit action Select wrong controls for recirc sump valve
EOP ES-1.3, Rev. 2	6e	Start 1 of 1 east RHR pump	Pump status	Control room	Omit action Select wrong controls for east RHR pump
EOP ES-1.3, Rev. 2	6f	Open 1 of 1 CCP suction valve from east RHR Hx (1-IMO-340)	Valve position	Control room	Omit action Select wrong controls for CCP suction valve

TABLE 3.3-3
WORKSHEET FOR CALCULATION OF p_c

Scenario: Small LOCA with success of ECCS high pressure injection (HP2), success of RCS cooldown using AFW (AF4), and success of containment spray injection (CSI)

HI: HPR - Switchover to high pressure cold leg recirculation

Cue(s): RWST at low level (alarm)

Duration of time window available for action (T_W): 340 Seconds.
17 min - 680 sec = 340 sec (per Reference 26, actions take 680 sec)

Approximate start time for T_W: 30 min

Procedure and step governing HI: Caution statement at beginning of ES-1.2

A. Initial Estimate of p_c

	p_c Failure Mechanism	Branch	HEP
p_ca:	Availability of information	a/b	neg.
p_cb:	Failure of attention The RxO should not have much distracting him at this point following a small LOCA (per operator interviews).	d	1.5E-4
p_cc:	Misread/miscommunicate data no data communicated - just instruction to watch level	n/a	n/a
p_cd:	Information misleading	a	neg.
p_ce:	Skip a step in procedure Caution statement is italicized and in all CAPS.	b	3.0E-3
p_cf:	Misinterpret instruction	a	neg.
p_cg:	Misinterpret decision logic	k	neg.
p_ch:	Deliberate violation	a	neg.

Sum of p_ca through p_ch = Initial p_c 3.1E-3

Total reduction in T_W = ______ min.

Effective T_W = ______ min.

Check here if recovery credit claimed on page 2: xx

Notes:
There are two RWST level indicators for the operators to use, a chart recorder and an indicator that is very easy to read.

TABLE 3.3-4
WORKSHEET FOR CALCULATION OF p_c RECOVERY FACTORS

Scenario: Small LOCA with success of ECCS high pressure injection (HP2), success of RCS cooldown using AFW (AF4), and success of containment spray injection (CSI)

HI: HPR - Switchover to high pressure cold leg recirculation

B. Recovery Factors Identified:

Alarm at low RWST level (did not credit this for b, because credit for alarm already in tree

C. Recovery Factors Applied to p_c

p_c Failure Mechanism	Initial HEP	Recovery Factor	Multiply by:	Final Value
$p_c a$				
$p_c b$	1.5E-4			1.5E-4
$p_c c$				
$p_c d$				
$p_c e$	3.0E-03	alarm T20-23(1)	.0001	3.0E-7

This is probably the only alarm going off, and at time much later than the initial alarms, so it will get more attention. Also, this red dot alarm is trained on as a high priority alarm.

p_c Failure Mechanism	Initial HEP	Recovery Factor	Multiply by:	Final Value
$p_c f$				
$p_c g$				
$p_c h$				

Sum of recovered $p_c a$ through $p_c h$ = Recovered p_c 1.5E-4

Time at which all recovery factors effective t=30 min

3.5 OLI - DEPRESSURIZATION TO ALLOW LOW PRESSURE INJECTION

3.5.1 Application

Medium LOCA (MLO) with failure of high pressure injection (HP2) - OLIA (JMR)

3.5.2 Description

Following the occurrence of a medium LOCA, if the high head pumps fail to start or fail to provide adequate cooling (HP2), the operators, by following emergency operating procedures, would be directed to depressurize the primary system to below the shutoff head of the RHR pumps to allow the RHR pumps to inject water to the core. The most effective means to perform this action is a rapid secondary depressurization (Reference 4a). If the RCPs are not all running, other actions include starting RCPs to provide forced two-phase flow through the core and/or opening the pressurizer PORVs to depressurize the RCS.

3.5.3 Success Criteria and Timing Analysis

Success of this event requires 450 gpm ($240x10^3$ PPH per EOPs) of AFW flow for the duration of the accident. Success criteria of improved core cooling and increasing vessel inventory is achieved by actions of dumping steam from at least two of four steam generators and/or at least two of three pressurizer PORVs. These actions will allow for the start (or verify running) of at least one of two RHR pumps.

The MLO Event Tree description in the Event Tree Notebook provides a detailed description of the timing analysis assumed for meeting the success criteria of this event. The success criteria is based on the identification of inadequate core cooling (ICC) symptoms (high core exit TC indication) at around 30 minutes following MLO event initiation (Reference 25, MLO-35 example). Upon identification of ICC symptoms, the operators should be ready to perform the rapid cooldown with little time delay and then perform the remaining actions. Operator actions are provided in EOP FR-C.1.

3.5.4 Procedures

The Emergency Operating Procedure used to perform this task is FR-C.1, RESPONSE TO INADEQUATE CORE COOLING, Rev. 4.

FR-C.1 is entered from F-0.2, Core COOLING Critical Safety Function Status Tree on a RED condition.

For this event, entry into FR-C.1 will occur from the STA recognizing the red path from F-0.2. Operators will review the red path summary from the foldout pages when they transfer to E-1 from step 25 of E-0 and when they transfer to ES-1.2 from step 14 of E-1, but this is conservatively not credited.

3.5.5 Critical And Recovery Actions

The following are the primary tasks which must be completed for success of the MLO event tree OLI top event:

1. Recognize core exit TC indications greater than 1200°F on the F-0.2, CORE

COOLING Critical Safety Function Status Tree or on the red path summary (Item 2b on foldout) (cognitive)

2. Start RHR pumps (Step 5 of FR-C.1) (Per operator interviews, the RHR pumps will probably still be running, but starting them is conservatively modelled.)

3. Initiate RCS cooldown at maximum rate using SG steam relief valves (conservatively not taking credit for condenser steam dump) (Step 13 of FR-C.1)

See Table 3.5-1, Cue Table for OLI for identification of symptoms for OLI actions.

See Table 3.5-2, Subtask Analysis For OLI for identification of critical or relevant recovery actions for OLI.

3.5.6 Assumptions

This action will be required at about the same time that switchover to recirculation will be required. Many factors influence which will come first, therefore, it is conservatively assumed that OLI precedes LPR and CSR. (This is conservative because OLI has a much higher THEP than LPR or CSR.)

3.5.7 Significant Operator Interview Findings

1. The STA will monitor the core exit thermocouple temperatures using the plant process computer, unless conditions are abnormal, upon which they will also monitor indication on the control room back panels.

2. The RCPs would be running when the operators reach step 12 of FR-C.1. (They will only stop the RCPs upon a medium LOCA if RCS pressure is less than 1250 psig and high head injection is available.) Since the pumps are already running when they reach this step ("Check if RCPs Should Be Started"), they will go on to step 13. Therefore, they will not open the pressurizer PORVs (RNO column for step 12).

3. The RHR pumps will probably still be running when the operators enter FR-C.1.

3.5.8 Calculation of Cognitive Error

A cognitive model was used to address diagnosis type errors (Reference 21). Table 3.5-3 contains the calculation of the cognitive human error probability, pc, that the STA fails to recognize the red path core cooling conditions. Pc was calculated in Table 3.5-3 to be 6.0E-03. Recovery was not applied to this value.

3.5.9 Calculation of Execution Error

For the calculation of execution errors, the tables from Chapter 20 of Reference 2 were used. (T20-x refers to Table 20-x of Reference 2.) The critical actions identified in Table 3.5-2 were reviewed to determine the dominant critical actions to be quantified. Critical actions are not dominant if they are recovered by other procedure steps or if they follow a mechanical failure because the human error probability would be multiplied by another human error probability or a mechanical failure probability. Attachment OLI is a copy of the relevant portion of FR-H.1, with dominant critical steps circled. The reasons why the other critical steps (identified in Table 3.5-2) are not dominant are also included.

Step 13, Initiate RCS Cooldown to 200°F:

13b Manually dump steam from intact SG(s) using steam relief valves

Errors of Omission:

Omit step/page:

4.2E-03 (T20-7 #4, Assumption G)

Step 13 of procedure

Errors of Commission:

Select wrong control when it is dissimilar to adjacent controls:

1.3E-03 (Table 20-12, #3)

The level and relief valve controls for the steam generators are well marked and different from adjacent controls on the steam generator panels. The only truly credible failure would be selecting the level control rather than the relief control.

3.5.10 Calculation of Total Human Error Probability for Failure to Depressurize (OLI)

The cognitive and execution error probabilities were calculated in sections 3.5.8 and 3.5.9 to be:

pc'(OLIA) = 6.0E-03
pe(OLI) = 5.5E-03 (without stress or dependence)

OLIA: Depressurize and Start RHR following a medium LOCA

An extremely high level of stress is assumed for red path recoveries. Per table 20-16, HEPs should be multiplied by two for moderately high stress for step-by-step tasks, and by 5 for extremely high stress for step-by-step tasks.

pc'(OLIA) = 6.0E-03 (OLI-----COG-HE)
pe'(OLIA) = 5.5E-03 * 5 = 2.8E-02 (OLI---13B-EHHE)

The total human error probability (THEP) for failing to depressurize following a medium LOCA and failure of high pressure injection is:

THEP(OLIA) = pc' + pe'

THEP(OLIA) = 6.0E-03 + 2.8E-02 = 3.4E-02

The corresponding fault tree is OLI1.

3.5.11 OLI Fault Trees Summary

The basic events and cutsets (with support system failures (i.e., SUBs) set equal to 1.0E-03) for the OLI fault tree are listed below.

Fault Tree OLI1
used for OLIA

```
VER 1.6
 oli1.cut                                                    Ver. 1.71  7/25/95   9:07:00

   2      2  3.383E-02  0.000E+00  1.000E-08
                1  OLI-----COG-HE         6.0000E-03     0.0000E+00
                2  OLI---13B-EHHE         2.8000E-02     0.0000E+00
                1.     2.80E-02     1     OLI---13B-EHHE
                2.     6.00E-03     1     OLI-----COG-HE
```

TABLE 3.5-1 - CUE TABLE FOR OLI (Depressurization and Low Pressure Injection) - MLO			
DIAGNOSIS	CUE	SUCCESS CRITERIA	LOCATION
Identify symptoms of inadequate core cooling on foldout page or on F-0.2, Core Cooling Status Tree	Core exit temperature > 1200°F - RED path	Recognize red path for core exit temperature > 1200°F, and transfer to FR-C.1	Control room

TABLE 3.5-2 - SUBTASK ANALYSIS FOR OLI (Depressurization and Low Pressure Injection) - MLO					
PROCEDURE		ACTION	INDICATION/ FEEDBACK	LOCATION	POTENTIAL ERRORS
NUMBER	STEP				
EOP FR-C.1, Rev. 4	5a (RNO)	Start RHR pumps	pump status	Control room	Omit action
					Select wrong controls for RHR pumps
EOP FR-C.1, Rev. 4	13b (RNO)	Dump steam at maximum rate using SG steam relief valves	steam relief valve position indication	Control room	Omit actions
					Select wrong controls for steam relief valves

TABLE 3.5-3
WORKSHEET FOR CALCULATION OF p_c

Scenario: Medium LOCA with success of accumulators and failure of high pressure injection

HI: OLI - Depressurization to allow low pressure injection

Cue(s): Red path conditions - foldout page or status tree

Duration of time window available for action (T_W): ________________ Seconds.

Approximate start time for T_W: 15 minutes

Procedure and step governing HI: F-0.2 Status Tree Red Path (i.e., STA)

A. Initial Estimate of p_c

	p_c Failure Mechanism	Branch	HEP
p_ca:	Availability of information	n/a	n/a
p_cb:	Failure of attention (assume low workload for STA) (per interview, STA will be watching computer screen for core exit thermocouple temperatures until things look abnormal, then they will check indicator on back panel -- per G. Parry, use front panel path for this tree)	e	3.0E-3
p_cc:	Misread/miscommunicate data	n/a	n/a
p_cd:	Information misleading	n/a	n/a
p_ce:	Skip a step in procedure (Status trees are monitored in particular order, and paths are graphically distinct using different colors and line types.)	b	3.0E-3
p_cf:	Misinterpret instruction	a	neg.
p_cg:	Misinterpret decision logic	k/l	neg.
p_ch:	Deliberate violation	a	neg.

Sum of p_ca through p_ch = Initial p_c 6.0E-03

Total reduction in T_W = ______ min.
Effective T_W = ______ min.

Check here if recovery credit claimed on page 2: _____

Notes:
Due to inconsistent useage of the foldout pages (per operator interviews), credit is conservatively not given to the US recognizing the red path from the foldout pages.

Attachment HPR

Title	Number
TRANSFER TO COLD LEG RECIRCULATION	01-OHP 4023. ES-1.3

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION:

- *ECCS RECIRCULATION FLOW TO RCS MUST BE MAINTAINED AT ALL TIMES.*
- *THE CONTAINMENT SUMP LEVEL (1-NLA-310/1-NLI-311) SHOULD BE GREATER THAN 97% OR THE CONTAINMENT LEVEL (1-NLI-320/1-NLI-321) SHOULD BE GREATER THAN 3% TO OPERATE ECCS IN THE RECIRCULATION MODE.*
- *ANY PUMPS TAKING SUCTION FROM THE RWST SHOULD BE STOPPED UPON RECEIPT OF THE RWST LEVEL LOW-LOW/RHR PUMP TRIP ALARM (ANN 105 DROP 24).*
- *FOLLOWING SI RESET, AUTOMATIC REINITIATION OF SI WILL NOT OCCUR UNTIL REACTOR TRIP BREAKERS ARE CLOSED.*
- *IF OFFSITE POWER IS LOST AFTER SI RESET, MANUAL ACTION MAY BE REQUIRED TO RESTART SAFEGUARDS EQUIPMENT.*
- *IF UNIT WAS IN MODE 4 AT THE ONSET OF THE TRANSIENT, THEN 1-RH-104E AND 1-RH-104W SHOULD BE VERIFIED OPEN.*
- *SWITCHOVER TO RECIRCULATION MAY CAUSE HIGH RADIATION IN THE AUXILIARY BUILDING.* | CS-1

NOTE:

- *FRPs should not be implemented prior to the completion of step 6.*
- *Foldout page should be open.*

R 1. Reset SI Recovered by Steps 4c & 6d - will not be able to open sump valves unless have reset SI.

___ 2. Check RHR Pumps - BOTH OPERABLE

<u>IF</u> neither RHR pump is OPERABLE, <u>THEN</u> go to ECA-1.1, LOSS OF EMERGENCY COOLANT RECIRCULATION, Step 1.

<u>IF</u> East RHR pump is INOPERABLE, <u>THEN</u> go to Attachment A.

<u>IF</u> West RHR pump is INOPERABLE, <u>THEN</u> go to Attachment B.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
___ 3.	Check CCW Pumps - BOTH OPERABLE	IF East CCW pump is INOPERABLE, THEN: a. Stop the East RHR pump and place in PULL-TO-LOCK. b. Go to Attachment A. IF West CCW pump is INOPERABLE, THEN: a. Stop the West RHR pump and place in PULL-TO-LOCK. b. Go to Attachment B.

CAUTION: WHEN CONTROL POWER IS RESTORED FOR VALVE OPERATION, THE CONTROL POWER MUST BE LEFT ON SO ASSOCIATED INTERLOCKS WILL BE OPERABLE.

___ 4. Align West RHR And CTS Pumps For Recirculation:

a. Stop the following pumps and place in PULL-TO-LOCKOUT position:

- West RHR pump
- West CTS pump

b. Close the following valves concurrently:

- R 1-IMO-320, West RHR pump suction valve Recovered by 4c - due to interlock.
- 1-IMO-225, West CTS pump suction valve from RWST
- 1-IMO-324, West RHR pump discharge crosstie valve normally closed (through injection and recirculation)

This Step continued on the next page.

HPR-2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
	c. Restore control power and open 1-ICM-306, Recirc sump to West RHR/CTS pump valve	c. Perform the following: 1) Open 1-IMO-225, West CTS pump suction valve from RWST. 2) IF West CTS pump was previously running, THEN restart the West CTS pump. IF NOT, THEN place the West CTS pump in NEUTRAL. 3) Go to Attachment B.
	d. Start the West RHR pump	d. IF the West RHR pump can NOT be started, THEN: 1) IF West CTS pump was previously running, restart the West CTS pump. IF NOT, THEN place West CTS pump in NEUTRAL. 2) Go to Attachment B.
	e. Check West CTS pump status - PREVIOUSLY RUNNING 1) Restart the West CTS pump 2) Verify ESW to/from West CTS heat exchanger valves - OPEN: • 1-WMO-715 • 1-WMO-717	e. Place West CTS pump in NEUTRAL

HPR-3

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION:
- *IF THE SI PUMP MINIFLOW VALVES ARE CLOSED, THEN THE SI PUMPS SHOULD BE STOPPED WHENEVER RCS PRESSURE APPROACHES THEIR SHUTOFF HEAD.*
- *IF RCS PRESSURE INCREASES TO 2000 PSIG, THEN A PRZ PORV SHOULD BE OPENED, AS NECESSARY, TO REDUCE RCS PRESSURE AND MAINTAIN MINIMUM CCP FLOW.*

NOTE: Minimum total BIT flow for CCP cooling is:
- *for 1 CCP - 150 gpm (160 gpm for adverse containment)*
- *for 2 CCPs - 275 gpm (280 gpm for adverse containment)*

___ 5. Align SI Pumps And CCPs For Recirculation:

R a. Reset both CCP miniflow valves: Recovered by 5c.

- 1-QMO-225
- 1-QMO-226

b. Check total BIT flow - GREATER THAN MINIMUM NEEDED FOR CCP COOLING

b. Perform the following:

1) Stop all but one CCP.

2) IF total BIT flow is greater than 150 gpm (160 gpm for adverse containment), THEN go to step 5c.

IF NOT, THEN open the associated CCP miniflow valve and go to step 5d.

WHEN RCS pressure is less than 1700 psig, THEN close all CCP miniflow valves.

c. Close both CCP miniflow valves:

- 1-QMO-225
- 1-QMO-226

These valves close upon SI signal initiation and only reopen when RCS pressure goes above 2000 psi (ie- they should already be closed).

This Step continued on the next page.

HPR-4

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
	d. Check the following valves for the North SI pump - OPEN • 1-ICM-260, North SI pump discharge to cold legs 1 & 4 normally open valve -AND- • 1-IMO-316, RHR and SI to RCS cold legs valve normally open valve	d. Manually open valves. • 1-ICM-260 • 1-IMO-316 IF either valve remains closed, THEN stop the North SI pump. Go to step 5g.
	e. Check the following valves for the South SI pump - OPEN • 1-ICM-265, South SI pump discharge to cold legs 2 & 3 normally open valve -AND- • 1-IMO-326, RHR and SI to RCS cold legs valve normally open valve	e. Manually open valves. • 1-ICM-265 • 1-IMO-326 IF either valve remains closed, THEN stop the South SI pump. Go to step 5g.
	f. Close SI discharge crosstie valves: • 1-IMO-270 • 1-IMO-275	These valves only need to be closed for a pipe rupture. Pipe rupture frequencies are insignificant.
	g. Check each SI pump flow - GREATER THAN 70 GPM: • 1-IFI-260 • 1-IFI-266	g. Stop affected SI pump(s). WHEN RCS pressure is less than 1425 psig (1150 psig for adverse containment), THEN start SI pump(s).
R	h. Restore control power and close SI pumps recirc to RWST valves: • 1-IMO-262 • 1-IMO-263	Recovered by Steps 5i and 6f due to interlocks.
	i. Open 1-IMO-350, SI pump suction from West RHR HX valve	i. Locally open 1-IMO-350. DO NOT PROCEED UNTIL 1-IMO-350 IS OPEN.

This Step continued on the next page.

HPR-5

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
j.	Open SI pump suction crosstie to CCP valves: • 1-IMO-361 • 1-IMO-362	
k.	Verify 1-IMO-360, SI pump suction crosstie CCPs - OPEN normally open valve	
l.	Restore control power and close 1-IMO-261, SI pump suction from RWST	only critical upon check valve failure, which is negligible
m.	Close CCP suction from RWST valves: • 1-IMO-910 • 1-IMO-911	only critical upon check valve failure, which is negligible
n.	Check CCP's - BOTH RUNNING	n. IF CCPs were stopped because of RWST low-low level, THEN perform the following: 1) Start one CCP. 2) Check total BIT flow - greater than 150 gpm (160 gpm for adverse containment) IF NOT, THEN open associated miniflow valve and go to step 5o. 3) Check RCS pressure - less than 1700 psig IF NOT, THEN go to step 5o. WHEN RCS pressure is less than 1700 psig, THEN restart all CCPs. 4) Start second CCP.

This Step continued on the next page.

HPR-6

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
	o. Check SI pumps - BOTH RUNNING	o. IF SI pumps were stopped because of RWST low-low level, THEN perform the following: 1) Check RCS pressure - less than 1425 psig (1150 psig for adverse containment) IF NOT, THEN go to step 6. WHEN RCS pressure is less than 1425 psig (1150 psig for adverse containment, THEN do step 5o. 2) Check SI pump discharge crosstie valves - closed: • 1-IMO-270 -OR- • 1-IMO-275 3) IF SI pump discharge crosstie is isolated, THEN start both SI pumps. IF NOT, THEN start only one SI pump.

HPR-7

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
6	Align East RHR And CTS Pumps For Recirculation:	
	a. Check RWST Level - LESS THAN 10%	a. Continue with step 7. WHEN RWST level drops to 10%, THEN do steps 6b through 6h.
	b. Stop the following pumps and place in PULL-TO-LOCKOUT position: • East RHR pump • East CTS pump	
	c. Close the following valves concurrently: R • 1-IMO-310, East RHR pump suction valve • 1-IMO-215, East CTS pump suction from RWST valve • 1-IMO-314, East RHR pump discharge crosstie valve	Recovered by Step 6d due to interlock Normally closed (through injection and recirculation)
	d. Restore control power and open 1-ICM-305, Recirc sump to East RHR/CTS pump valve	d. Restore control power and close 1-IMO-390, RHR pumps suction from RWST. Go to step 7.
	e. Start the East RHR pump	e. Go to step 6g.
	f. Open 1-IMO-340, CCP suction from East RHR HX valve	
	g. Check East CTS pump - PREVIOUSLY RUNNING 1) Restart the East CTS pump 2) Verify ESW to/from East CTS heat exchanger valves - OPEN • 1-WMO-711 • 1-WMO-713	g. Place East CTS pump in NEUTRAL
	h. Restore control power and close 1-IMO-390, RHR pumps suction from RWST	

HPR-8

Attachment OLI

Title	Number
RESPONSE TO INADEQUATE CORE COOLING	01-OHP 4023. FR-C.1

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
___ 4.	Verify ECCS Valve Alignment - PROPER EMERGENCY ALIGNMENT BY STATUS LIGHTS. • 1-SML-11A,B,C • 1-SML-12A,B,C	Manually align valves as necessary.

___ 5.	Verify ECCS Flow In All Systems:
	• BIT flow - ON SCALE:
	  • 1-IFI-51
	  • 1-IFI-52
	  • 1-IFI-53
	  • 1-IFI-54
	• SI pump flow - ON SCALE:
	  • 1-IFI-260
	  • 1-IFI-266
	• RHR HX outlet flow - ON SCALE:
	  • 1-IFI-310 or 311
	  • 1-IFI-320 or 321
		Perform the following:
		a. Start all available ECCS pumps:
		  • CCPs
		  • SI pumps
		  R • RHR pumps - recovered by step 14 (may already be running)
		b. Establish BIT flow from the positive displacement pump (PDP):
		  1) Locally open PDP suction and discharge valves:
		    • 1-CS-304
		    • 1-CS-306
		  2) Start the PDP.
		  3) Adjust 1-QRV-251, CCP flow control valve to allow PDP flow to the BIT.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE: Normal conditions are desired but not required for starting the RCPs.

per operator interviews, RCPs would still be running, so they would skip this step

___ 12. Check if RCPs Should Be Started:

a. Core exit TCs - GREATER THAN 1200°F.

a. Go to Step 13.

b. Check if an idle RCS cooling loop is available:

- Narrow range SG level - GREATER THAN 6% (22% FOR ADVERSE CONTAINMENT)
- RCP in associated loop - AVAILABLE AND NOT OPERATING

b. Perform the following:

1) Open all PRZ PORVs and block valves.

2) IF core exit TCs remain greater than 1200°F, THEN open other RCS vent paths to containment:

a) PRZ vent path valves:

- 1-NSO-61 and 1-NSO-62

-OR-

- 1-NSO-63 and 1-NSO-64

b) Reactor head vent path valves:

- 1-NSO-21 and 1-NSO-22

-OR-

- 1-NSO-23 and 1-NSO-24

3) Go to Step 13.

c. Start RCP in one idle RCS cooling loop.

d. Return to Step 12a.

CS-1

OLI-2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION: DURING COOLDOWN, STEAM FLOW OF GREATER THAN 1.42x10^6 PPH ON TWO OR MORE SGs WILL RESULT IN A STEAMLINE ISOLATION.

NOTE:

- *Partial uncovering of SG tubes is acceptable in the following steps.*
- *Both steam dump control selector switches should be momentarily placed in BYPASS INTERLOCK when Tavg decreases to 541°F.*

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
13.	Initiate RCS Cooldown To 200°F:	
	a. Transfer condenser steam dump to steam pressure mode	
	b. Dump steam to condenser from intact SG(s) at maximum rate	b. Manually or locally dump steam from intact SG(s) at maximum rate using steam relief valves.
	c. Check RCS hot leg temperatures - DECREASING	c. Cooldown using faulted or ruptured SG(s).

 CS-1

OLI-3

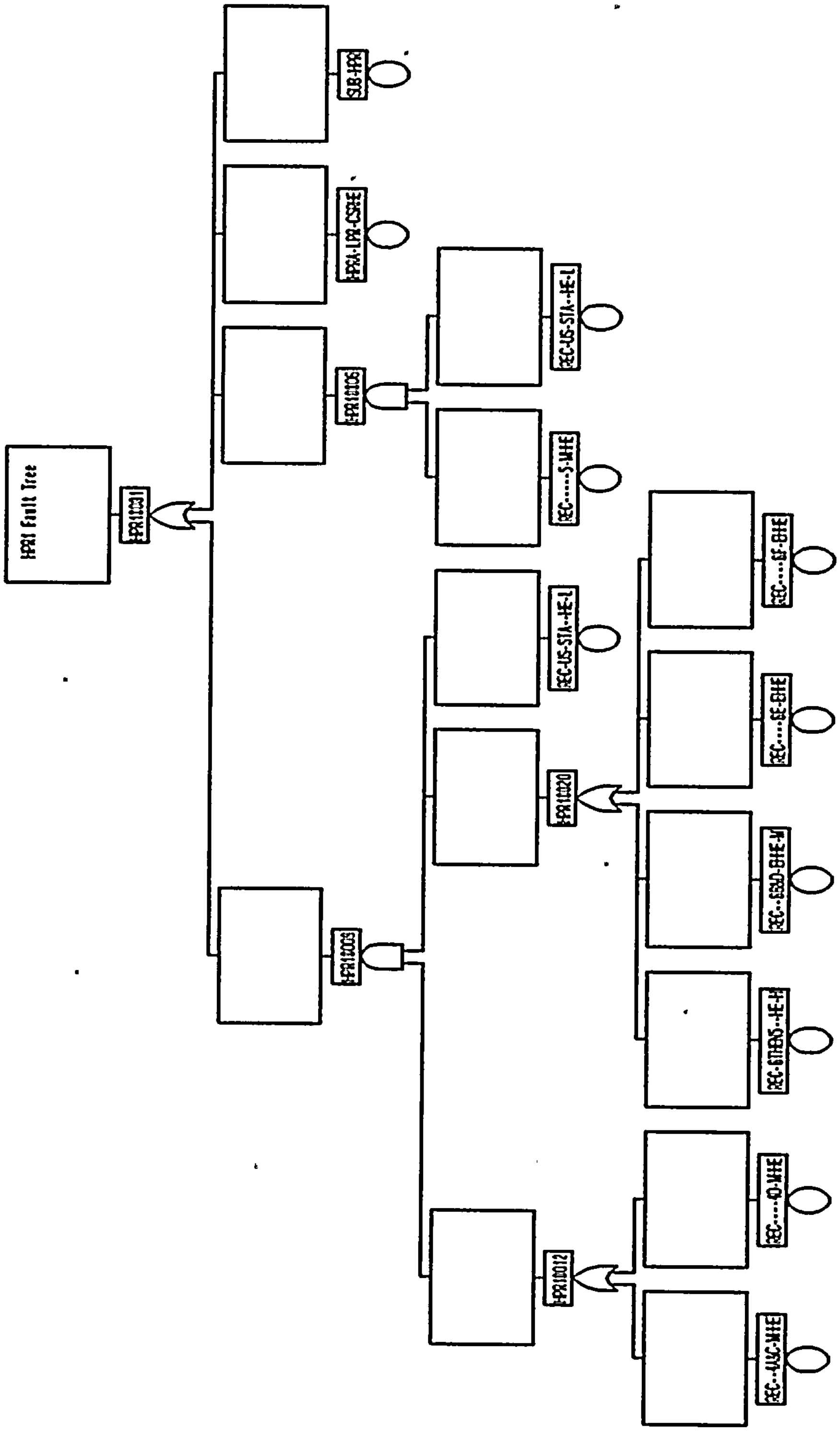
STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
___ 14.	Verify ECCS Flow: • BIT flow - ON SCALE • 1-IFI-51 • 1-IFI-52 • 1-IFI-53 • 1-IFI-54 -OR- • SI pump flow - ON SCALE • 1-IFI-260 • 1-IFI-266 -OR- • RHR HX outlet flow - ON SCALE • 1-IFI-310 or 311 • 1-IFI-320 or 321	Continue efforts to establish ECCS flow. IF BIT flow is NOT on scale AND core exit T/Cs are greater than 1200°F, THEN perform the following: a. Request an immediate Unit 2 shutdown. b. Request Unit 2 establish charging pump operation with suction from the RWST. c. WHEN Unit 2 charging is available and aligned to the RWST, THEN establish BIT flow from Unit 2. Refer to Attachment A.

Recovery for Step 5, since Charging and SI pumps have failed.

CS-1

OLI-4

FIGURE E-8
HPR1 FAULT TREE



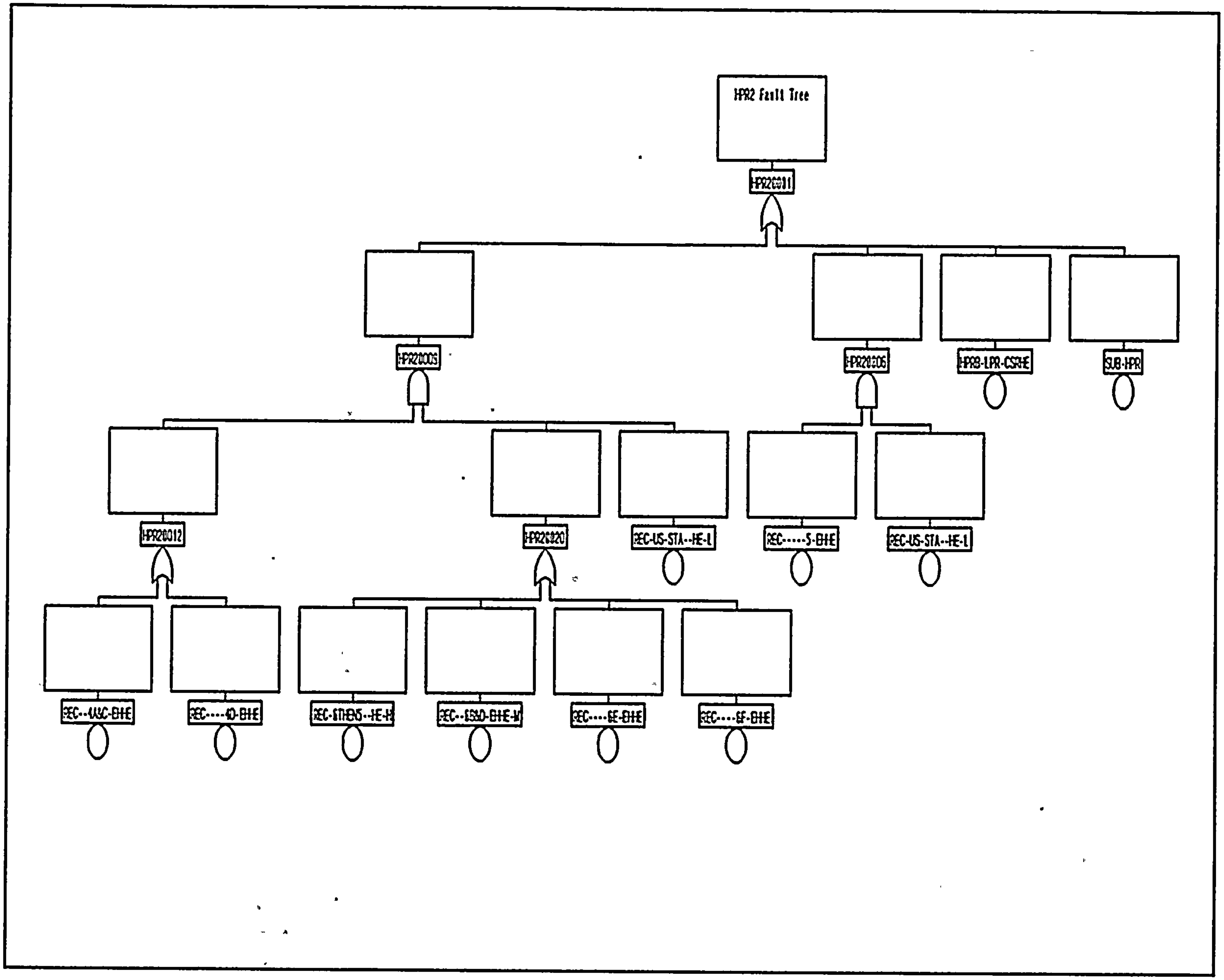


FIGURE E-9
HPR2 FAULT TREE

FIGURE E-10
HPR3 FAULT TREE

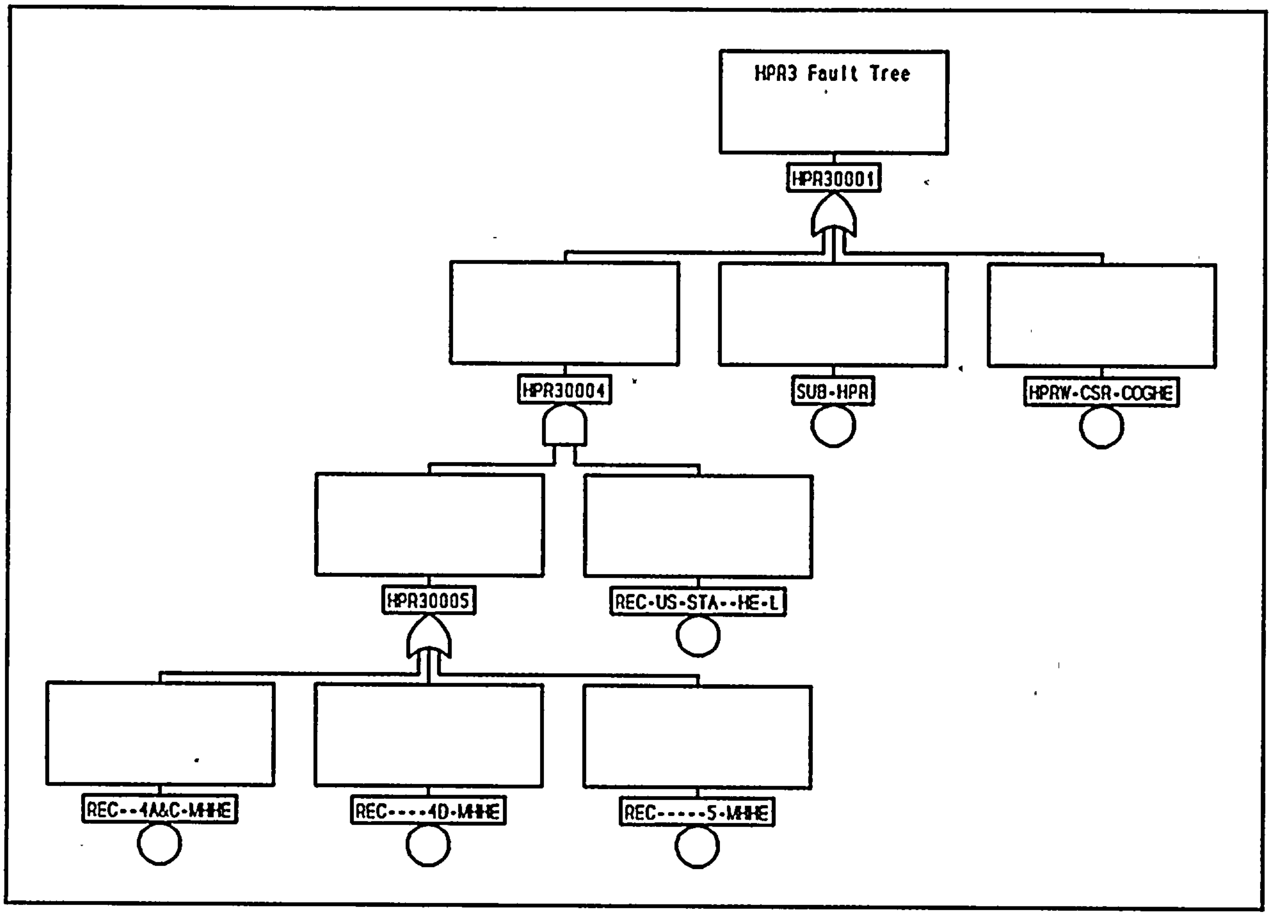
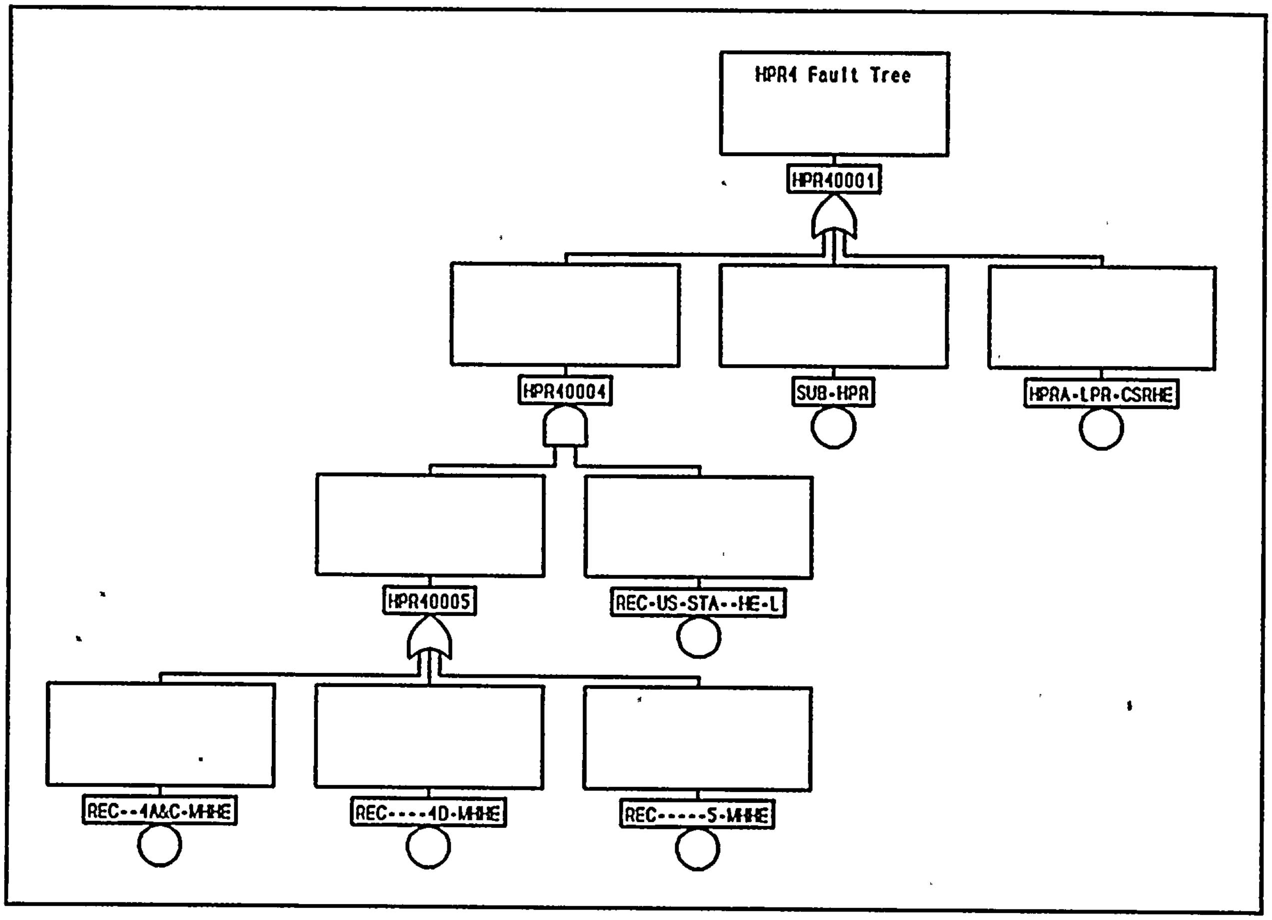


FIGURE E-11
HPR4 FAULT TREE



ATTACHMENT 1 TO AEP:NRC:10820

Donald C. Cook Nuclear Plant
Individual Plant Examination

Individual Plant Examination
Revision 1

COOK NUCLEAR PLANT

Bridgman, Michigan

INDIVIDUAL PLANT EXAMINATION
REVISION 1