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SAFETY EVALUATION REPORT RELATED TO POINT BEACH UNIT 1 STEAM GENERATOR TUBE DEGRADATION DUE TO DEEP CREVICE CORROSION

INTRODUCTION

Inservice inspections of the Point Beach Unit 1 steam generators performed during the August 1979 and October 1979 outages indicate extensive general intergranular attack (IGA) and caustic stress corrosion cracking on the external surfaces of the steam generator tubes within the thickness of the tube sheet. This condition appears to have developed rapidly during the last twelve (12) months as evidenced by small primary to secondary generator tube leaks occurring on September 20, 1978 and March 1, August 5, and August 29, 1979. Ninety-seven (97) tubes were plugged as a result of the August 1979 inspection, and 145 tubes were plugged as a result of the October 1979 inspection. Of the 145 tubes plugged in the October inspection, 134 tubes were deemed defective due to the crevice corrosion phenomenon.

Following the October 1979 inspection, the NRC staff met with representatives of Wisconsin Electric Power Company (the licensee) and their Westinghouse consultants on November 5, and again on November 20, 1979 to discuss the operational experience at Point Beach Unit 1 and the present condition of the steam generators. This included a discussion of the Point Beach Unit 1 operating history, results of the August and October 1979 steam generator inspections, results of laboratory examinations of tubes pulled during the October 1979 outage, laboratory tests and calculations to demonstrate tube integrity, and

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the plans for remedial actions. Information provided by the licensee and Westinghouse at these meetings has formally been documented by letter dated November 23, 1979, from S. Burstein to H. R. Denton.

At the request of the NRC, Point Beach Unit 1 has not been returned to power pending a thorough safety evaluation by the NRC staff. A safety evaluation was deemed appropriate in view of the degradation which presently exists within the tubesheet crevices and because of the likelihood for continued tube degradation and new leaks, unless remedial measures are taken to retard the progress of the steam generator tube degradation.

OPERATIONAL HISTORY

Water Chemistry

Point Beach Unit 1 began commercial operation in December 1970 using phosphate secondary chemistry control. In addition to continuous feed, phosphates were batch-fed to the steam generators. Steam generator blowdown was performed intermittently. Numerous condenser leaks were experienced until modifications were made to the condensers in 1971. Sodium to phosphate (Na/PO_4) levels were generally high and free caustic was present in the secondary coolant through January 1972.

From January 1972 to September 1972, phosphate concentrations were increased using the same batch and continuous feeding methods. The periods of operation with free caustic were reduced and the Na/PO_4 ratios were generally controlled between 2.0 and 2.6. The unit was shut down for its first refueling in September 1972.

Following completion of the refueling and maintenance outage in March 1973, the phosphate feed system was modified to allow better control and continuous blowdown was initiated. In early 1974, the Na/PO_4 control ratios were adjusted to between 2.3 and 2.6. During the April 1974 refueling shutdown, the steam generators were sludge lanced. Tube lane blocking devices were installed in June 1974 to improve circulation and sludge removal.

In September 1974, an online conversion to all volatile treatment (AVT) was performed by discontinuing phosphate feed and initiating maximum steam generator blowdown. Online conversion was marginally successful, however, and free caustic was confirmed in November 1974. During November, a 48-hour shutdown and soak were performed for phosphate removal. The unit was sludge lanced and returned to power with AVT treatment.

During 1975, operation with AVT chemistry indicated free caustic was present during operation and sodium phosphate hideout return was present during unit shutdown. During 1976 and 1977, levels of free caustic generally decreased although free caustic was frequently detected. Sodium and phosphate continued to be detected during unit shutdowns. In 1978 and 1979, free caustic was normally below detection limits and sodium and phosphate, although still present, were much lower during unit shutdown. The continuing improvement in AVT chemistry control from 1975 to present has been due in large part to increased attention to condenser leakage and the continuing development of leakage detection capability.

The controlling parameter for he various corrosion mechanisms that lead tc tube degradation appears to be related to steam generator secondary water chemistry control. The predominant method of chemistry control at Point Beach Unit 1, prior to 1975, was coordinated pH-phosphate control. In late 1974, Point Beach Unit 1 converted from phosphate control to all-volatile treatment (AVT). Wisconsin Electric sludge lanced the steam generators and made minor changes to improve circulation.

The purpose of the chemistry changeover from phosphate chemistry control to AVT was principally to arrest tube thinning (wastage) that primarily occurred near but always above the tubesheet. The Unit 1 steam generators experienced significantly reduced rates of wall thinning following the chemistry conversion.

The objective of using phosphate control was to buffer inleakage of impurities from the condenser and to prevent formation of boiler scale on the steam generator tubes. Control of caustic level was also of concern. In fact, improper use of phosphate often leads to caustic stress corrosion. With the changeover to AVT control, caustic stress corrosion has remained a concern. Stress corrosion cracking after conversion from phosphate to AVT control is related to previous phosphate concentration and possibly to makeup water contamination. Plants with only short periods of phosphate control have not experienced operational problems due to wall thinning or caustic stress corrosion cracking.

A second significant effect on the conversion to AVT upon wastage has occurred due to a change in the character of steam generator sludge deposits. With a phosphate feed, the sludge is coarse, granular material that forms a cohesive mass on the tubesheet. Operation with AVT after a period of phosphate treatment results in a finely divided sludge of dense particles that are more easily removed by water-lancing procedures. This sludge is similar in metal composition to the phosphated sludge because the iron impurities in the feedwater are unchanged. The improved ability to remove the "AVT sludge" minimizes wastage of steam generator tubes.

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Tube Integrity - Plugging History

Wastage and Caustic Stress Corrision: - The early history of tube degradation at Point Beach Unit 1, since beginning commercial operation in December 1970 with a phosphate secondary water chemistry, was highlighted by the accumulation of a substantial amount of sludge deposits on the tubesheets, and the occurrence of wastage and caustic stress corrosion located for the most part just above the tubesheet in both steam generators. By September 1972, a total of 178 tubes in both steam generators had been plugged. However, only two tubes required plugging in the subsequent April 1974 inspection, apparently reflecting improved control of sodium to phosphate (Na/PO_4) ratios and free caustic in the secondary water.

The changeover to AVT secondary water chemistry in September 1974 was performed on-line and without an intermediate sludge lancing, so that the sludge deposits remained essentially in place during the first few months of AVT operation until the first sludge lancing in November 1974.

On February 26, 1975, following the change over to AVT, a tube rupture occurred resulting in a 125 gpm primary-to-secondary leak. Subsequent inspection indicated that a combination of wastage and caustic stress corrosion cracking (SCC) had occurred resulting in the tube failure located a few inches above the tubesheet. A total of 157 tubes were plugged as a result of the inspection performed following the tube rupture incident. Subsequent operating experience at Point Beach Unit 1 (since February 1975) indicates that the wastage and caustic SCC phenomenon above the tubesheet have essentially been arrested.

<u>Denting</u>: - Denting was first detected in November 1975, at Point Beach Unit 1, and currently affects the tube to tube support plate intersections of approximately 100 tubes. Of these, ten tubes were plugged in November 1977, and one in September 1978. The criteria for plugging includes the plugging of all tubes restricting the passage of a .540" eddy current probe, and the surrounding tubes.

The degree of denting at Point Beach Unit 1 is considered to be only moderate, and flow slot hourglassing has not been observed to date. The eddy current inspections performed in August and October 1979 indicated no progression in denting since the September 1978 inspection.

<u>Deep Crevice Cracking</u>: - The most recent concerns regarding the integrity of steam generator tubes at Point Beach Unit 1 involve corrosion damage to tubes within the thickness of the tubesheet. This phenomenon, known as "deep crevice cracking", affects early generation of Westinghouse designed steam generators in which the tubes were not fully expanded in the tubesheet. This "deep crevice cracking" involves both caustic intergranular attack and cracking within the tubesheet crevice. This phenomenon can affect steam generators which have converted from phosphate to AVT secondary water chemistry, such as Point Beach Unit 1, or have operated exclusively on AVT.

Although we are aware that the "deep crevice corrosion" phenomenon has been observed in at least seven other Westinghouse designed plants (San Onofre Unit 1, H. B. Robinson Unit 2, R. E. Ginna Unit 1, and Prairie Island Unit 2, and three foreign units) the Point Beach Unit 1 situation is unique in terms of the extent and the rapid progression in the last twelve (12) months.

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The eddy current testing did not

The "deep crevice cracking" phenomenon at Point Beach Unit 1 was first detected in November 1977, and has caused several small tube leaks (1.5 gpm) in the last twelve months. Prior to the August 1979 inspection, a total of 22 tubes were plugged because of deep crevice cracking.

DISCUSSION

August 1979 Steam Generator Inspection

Following a return to power on August 5, 1979 after being shutdown to repair a high pressure turbine steam leak and to make a temporary repair to the auxiliary feedwater line, a 1.45 gpm (2088 gpd) leak developed in steam generator A. This leakage exceeded the Technical Specification limit of .35 gpm (500 gpd), and the plant was shutdown. Subsequent hydrostatic leak testing and eddy current testing (ECT) revealed three leaking tubes which failed within the thickness of the tubesheet (tubesheet crevice region). In addition, the 100% eddy current inspection of the hot leg tubes in both steam generators A and B indicated 52 tubes and 45 tubes, respectively, with deep crevice cracking indications in excess of the 40% plugging limit. These crack indications generally occurred in the "kidney" shaped region of low flow velocity. No cold leg indications were found. Six percent of the hot leg tubes were probed around the U-bend to the cold leg side. The remaining tubes were probed through the first support plate. The eddy current testing was performed with a 400 KHz probe.

The eddy current testing in August did not indicate any progression in wastage or caustic stress corrosion cracking above the tubesheet since the previous inservice inspection in September 1978, nor did the six percent tube sample indicate progression of tube denting.

The unit was returned to power on August 19, 1979, following the steam generator repair outage. However, on August 29, 1979 the Unit was again shutdown due to a 324 gpd leak which is less than the Technical Specification limit of 500 gpd. This leak had existed since the August 19 restart, increasing at the rate of approximately 40 gpd per day. Subsequent inspection and a review of the tape record of the 100% eddy current inspection performed during the earlier outage showed that the leaking tube was one of two tubes with eddy current indications exceeding the plugging limit but inadvertently left unplugged. These indications (ECT indication for leaker was 88%) were apparently overlooked during the licensee's data evaluation effort and were not identified as pluggable.

The leaking tube was plugged and the unit was returned to service on September 2, 1979.

October 1979 Steam Generator Inspection

For the October 1979 refueling outage, the licensee had originally scheduled 75 tubes in each steam generator for eddy current inspection as part of a continuing monitoring program. These tubes were located in the kidney shaped zone of the hot leg side where the deep crevice cracking phenomenon had been observed previously. Based upon the number of tubes with pluggable indication (>40% of the tube wall thickness removed), the sample size was first increased to 200 tubes, and finally to 100% of the tubes in both steam generators per Technical Specification requirements. In all, 77 tubes in steam generator A and 68 tubes in steam generator B were plugged. This included, for steam generator A, two (2) tubes with no indications that were pulled for laboratory analysis, three (3) tubes with defects less than the plugging limit (all tubes with detectable indications were plugged), and two (2) tubes which were plugged by mistake. The 68 tubes plugged in steam generator B included three (3) tubes with defects less than the plugging limit and one plugged by mistake.

To assure that all tubes containing detectable ECT indications were actually plugged, the eddy current tapes were reviewed by two qualified engineers or technicians. In addition, tubesheet photographs were taken and hydrotesting was performed to detect mis-located plugs.

As a result of the October 1979 steam generator inspection, a total of 10.1% of the tubes in steam generator A and 9.8% of the tubes in steam generator B have been plugged. The previously NRC-approved LOCA-ECCS analysis was only valid for tube plugging up to 10% in each steam generator. Therefore, the licensee submitted for NRC approval a revised analysis to demonstrate acceptable ECCS performance during LOCA for tube plugging up to 18%. The acceptability of this report is addressed in Appendix B of this SER.

Whereas eddy current testing during the previous steam generator inspection in August 1979 had been performed for the most part using the single frequency (400 KHz) probe, all eddy current testing in October 1979 was performed using a multifrequency (10, 100, and 400 KHz) probe. Basically, the multifrequency technique provides enhanced capability for the discrimination of defects against noise or interference effects (e.g., support plates). However, since both techniques involve the collection of data at 400 KHz, it was possible to perform a direct comparison of the August and October 1979 eddy current test results. A reevaluation of the eddy current tapes from the August 1979 inspection revealed the following distribution of degradation for tubes identified as having greater than 20% indications in October 1979:

Category	400 KHz Data-August 1979	No. of Tubes SG A	No. of Tubes SG B
1.	No detectable indications	12	12
2.	Noisy signals - no estimate possible	37	29
3.	Tape Record unavailable for review	6	5
4.	Eddy current signals >40%	17	13
5.	Eddy current signals <40%	0	1
6.	Tubes not compared	1	7
	No. tubes plugged per Oct. 79 ECT data	73	67

Thus, the number of tubes plugged in October 1979 is not necessarily wholely indicative of additional tube degradation occurring since August 1979, but could reflect enhanced capability to detect tube defects using the multi-frequency eddy current technique.

The average eddy current indications obtained for each of the above five tube categories are as follows:

Category	Average % ECT Indication (10/79) SG A	Average % ECT Indication (10/79) SG B
1.	73	80
2.	84	84
3.	78	75
4.	86*	75*
5.	-	36

* were 84% for S/G-A and 69% for S/G-B, respectively, in August, 1979

The following tables describe the distribution of eddy current indication by their depth of penetration and their location or elevation within the tubesheet crevice for both the August and October 1979 inspections.

DISTRIBUTION OF INDICATIONS (percent)

By Depth of Wall Penetration

	40-49%	50-59%	60-69%	70-79%	80-89%	90-100%
SG A	1	2.5	3.4	12.1	40.5	40.6
SG B	2.6	1.8	8.8	14.1	34.1	38.6

By Location in Tube Crevice ("from tube end)

	0-4"	5-9"	10-14"	15-19"	20"-top of tube sheet
SG A	0	15.2	16.0	26.4	42.4
SG B	3.6	23.2	27.7	21.4	24.1

No crevice indications extending above the tubesheet have been observed to date.

Laboratory Examinations

Segments of three tubes were pulled during the October 1979 outage for further study of the deep crevice cracking phenomenon. One tube (R15-C45; i.e., Row 15, Column 45) was taken from the "kidney" shaped zone of previous deep crevice corrosion activity and contained an 89% eddy current indication. The second tube (R22-C37) was also taken from "kidney" shaped zone, but contained no field eddy current indication. The third tube (R20-C73) was taken outside the zone of previously observed activity, and which also did not exhibit eddy current indications during field examinations.

Tube R15-C45 was cut just below the first support plate, but broke at the location of the indicated defect during removal. The break occurred under a pulling force of about 25,600 pounds without significant plastic elongation.

Tubes R22-C37 and R20-C73 were cut below the first and second support plates, respectively, and required force applications of 25,400 and 13,000 pounds for removal. These pulling loads induced in excess of 10% elongation of the tubes.

These tubes were delivered to the Westinghouse R&D Center where they were subjected to intensive analyses including laboratory ECT, radiography, metallography, microanalysis, and testing for mechanical properties and integrity.

Metallurgical Examination: - Metallographic examination revealed a general condition of (uniform) intergranular attack (IGA) within the crevice regions of each of the three tubes examined. Various microanalytical techniques indicate this condition to be a result of a residual caustic materials remaining from phosphate chemical treatment and possibly from earlier condenser tube leakage. No intergranular attack or cracks were found in the tube specimens above the tube sheet.

Tube R15-C45, which showed an 89% in-plant eddy current indication, exhibited uniform IGA 40% through wall and cracks about 90% through wall adjacent to the location of the in-plant eddy current indication, thereby confirming the in-plant eddy current signal. This was also confirmed by SEM fractography of the fracture surface.

Tubes R22-C37 and R20-C73 showed uniform IGA about 10% and deeper crack penetration to 50% and 33% of the wall, respectively. For tube R20-C73, a metallographic sample was taken which extended 3/4" above and below the top of the tubesheet, with no IGA observed along the entire length.

The results for Tubes R22-C37 and R20-C73 are of particular interest since they exhibited no eddy current indications during in-plant inspection. However, the local crack penetration was detected during laboratory eddy current examination, and it is therefore likely that these cracks were developed under the high tensile loads during the tube removal process.

The licensee and Westinghouse conclude that the eddy current testing is currently not able to detect intergranular corrosion within the tubesheet. Significant (>20 percent through wall) cracks or tube wall penetrations in the tubesheet area are, however, detectable by eddy current testing. The conditions within the tubesheet crevices are such that the tubing material affected by intergranular corrosion is held in place by the tubesheet itself and the crevice condition shows a minimum of grain dislocations or material loss. As a result, the grains in the suspect region remain in physical and electrical contact providing a continuous path for eddy currents induced in the tubewall when the eddy current test is performed. The material, therefore, may show no eddy current indication of the corrosion within the tubesheet crevices unless there is cracking through a portion of the tube wall.

<u>Mechanical Testing:</u> - Specimens were removed from R15-C45 and R22-C37 for mechanical tests. Tensile tests, lead plug tests, and burst tests were performed.

The tensile test results indicated that the properties of the base core material which has not seen general intergranular attack is similar to virgin material in terms of strength and ductility.

Lead plug burst tests were run on specimens from tube R15-C45 for the purpose of determining the diametral expansion of the tube prior to failure. The results demonstrate that the tube has sufficient ductility to expand into contact with the tubesheet within the crevice.

Burst tests were performed with specimens from tubes R15-C45 and R22-C37 with the following results:

1. Samples removed from the intergranularly attacked region of each tube (at least 5 inches below top of tubesheet) exhibited burst pressure of 5100 psi and 6800 psi for tubes R15-C45 and R22-C37, respectively. The maximum pressure applied during a MSLB will be approximately 2000 psi.

2. A 5 inch tube sample from Tube R22-C37 at a location extending down to 2 1/2 inches below the top of the tubesheet exhibited a burst strength in excess of 11700 psi. Thus, there was no degradation in burst strength relative to that for a virgin tube. This corresponds with the result of the metallurgical examination which indicated no intergranular attack above the tubesheet.

Tube Integrity

On the basis of test results and analysis, the licensee concludes:

Inside the Tubesheet

1. 10% remaining wall thickness (i.e. not penetrated by IGA or cracks) is required to ensure that a double ended tube failure will not

occur during a postulated main steam line break (MSLB), and is indicated to exist by the condition of the tubes examined and the test results.

2. Ductility will allow a degraded tube to expand to contact tubesheet (i.e. no tube burst during MSLB).

3. Tube collapse during LOCA is highly unlikely since tube ovalization during collapse would be constrained by the tubesheet.

4. The maximum leak rate as a result of a crack within the tubesheet is governed by the annular gap. Tube breaks 0.15 inch or more below the top of the tubesheet will not pull out of the tubesheet during MSLB because of the restraint of the tube bundle. For breaks within 0.15 inches of the top of the tubesheet, leak rates will be large enough to allow detection during normal operation.

Outside the Tubesheet

1. The conditions of the tubes examined and the test results indicate that intergranular attack does not occur outside the tubesheet crevices.

2. 40% remaining wall is required to resist pressure loading during a LOCA, and is indicated to exist.

3. Test results show that the leak-before-break criteria is valid and will require timely shutdown and corrective actions.

Remedial Actions

The licensee plans to, or already has, implemented the following interim measures to provide additional assurance of continued safety:

1. A hydrostatic test has been successfully performed at 800 psi secondary to primary pressure. Such test pressure exceeds the pressure which might be imposed on the steam generator tubes in the event of a loss-of-coolant accident.

2. A primary to secondary hydrostatic test has been successfully performed at 2000 psi. This test pressure exceeds that which could develop during a steamline or feedwater line break and, thus, demonstrates the tubes' ability to maintain their integrity during such events.

3. Upon NRC approval of the Technical Specification change requested by letter dated November 2, 1979, the reactor coolant system would be operated at the nominal pressure of 2000 psia rather than 2250 psia. This would reduce internal pressure stresses during operation approximately 15%.

4. (a) Within 30 effective full power days, a 2,000 psi primary to secondary hydrostatic test and a 800 psi secondary to primary hydrostatic test will be performed. Should any significant leakage develop as a result of either test, the leaking tubes will be identified and plugged.

(b) Within 60 effective full power days, the same primary to secondary and secondary to primary hydrostatic tests will be repeated, and an eddy current examination of the steam generator tubes will be performed. This eddy current program will be submitted to the NRC for Staff review.

5. Primary coolant activity for Point Beach Nuclear Plant Unit 1 will be limited in accordance with the provisions of Sections 3.4.8 and 4.4.8 of the Standard Technical Specifications for Westinghouse Pressurized Water Reactors, Revision 2, July 1979, rather than Technical Specification 15.3.1.C. The acceptability of this action is addressed in Appendix C of this SER.

6. Close surveillance of primary to secondary leakage will be continued and the reactor will be shut down for tube plugging on detection and confirmation of any of the following conditions:
   a. Sudden primary to secondary leakage of 150 gpd (0.1 gpm) in either steam generator;
   b. Any primary to secondary leakage in excess of 250 gpd (0.17 gpm) in either steam generator; or
   c. An upward trend in primary to secondary leakage in excess of 15 gpd (0.01 gpm) per day, when measured primary to secondary leakage is above 150 gpd.

7. The reactor will be shutdown, and leaking steam generator tubes plugged, and an eddy current examination performed if any of the following conditions are present:

   a. Confirmation of primary to secondary leakage in either steam generator in excess of 500 gpd (0.35 gpm); or

   b. Two leaking tubes are identified within a 20-day period.

   This eddy current program will be submitted to the NRC for Staff review.

8. The NRC Staff will be provided with a summary of the results of the eddy current examinations, including a description of the quality assurance program covering tube examination and plugging. This summary will include a photograph of the tubesheet of each steam generator which will verify the location of tubes which have been plugged.

9. The licensee has completed a review of Emergency Operating Procedure 3A, Revision 9, dated March 29, 1978, and has confirmed that this procedure is appropriate for use in the case of a steam generator tube rupture. This procedure has been reviewed and found acceptable by NRC.

10. The licensee will complete a retraining program for all licensed reactor operators and senior reactor operators in the conduct of EOP-3A, the steam generator tube rupture procedure, before return to power operation.

In addition, the licensee plans to also implement the following measures in an attempt to retard further tube degradation:

1. The reactor coolant system hot leg temperature will be reduced to approximately 557 F. This will result in lower secondary steam pressure and, hence, lower power output due to limited flow capability of main turbine control valves. Maximum output under these conditions is expected to be 83% full power or 413 MWe net. Testing will be performed to assure main steam moisture carryover does not exceed design value of 0.25%.

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2. Close surveillance of feedwater chemistry conditions and condenser tube leakage will continue.

3. Sludge lancing will be performed within 12 months of return to power.

With regard to Item 1 above, deep crevice corrosion has not been observed to date on the cold leg side. The primary coolant temperature on the cold leg side is 542 F at 100%. It is hoped, therefore, that reduced temperature operation will be effective in retarding the rate of deep crevice corrosion on the hot leg.

EVALUATION

The staff has met on two separate occasions, November 5 and 20, 1979, with the licensee and their consultants to review the inspection results (both August and October, 1979 inspections) and to discuss the condition of the Point Beach Unit 1 steam generators and the measures which have been taken to assure their safe operation. In addition, the staff has also reviewed information submitted by the licensee on November 2, 1979 in response to our concerns regarding the apparent increase in the rate of deep crevice corrosion at Point Beach Unit 1. This information includes results of two successive 100% inspections of all the steam generator tubes using both single frequency and multi-frequency eddy current techniques, results of laboratory examinations of tube specimens that were removed from the tubesheet crevice regions, and results of analysis of degraded tube behavior under normal operating and postulated accident conditions.

Several levels of defense are generally relied upon to ensure steam generator tube integrity. These are inservice inspection, preventive tube plugging, and a primary to secondary leak rate limit.*

The following evaluation addresses the areas of inservice inspection, preventive tube plugging, primary-to-secondary leak rate limit, mechanical tube integrity and the licensee's proposed remedial actions.

Inservice Inspection and Preventative Tube Plugging

The licensee has performed a 100% inspection of the steam generator tubes using multi-frequency ECT, and all tubes with ECT indications in the crevice zone have been plugged. The 100% inspection of the steam generator tubes represents a total inspection of the tube crevice regions, and the multi-frequency ECT is the most sensitive technique currently available for this type of inspection. The plugging criteria were conservative in that it included tubes with any ECT indication in the crevice region. Furthermore, improved QA and QC procedures have been implemented to assure that all the tubes containing pluggable indications are indeed plugged. However, the accuracy of the ECT technique is somewhat diminished in the tubesheet region and cannot be fully relied upon to detect every tube degraded by deep crevice corrosion. This appears to be particularly true for tubes subject to general intergranular attack, but which do not contain cracks. Partially through wall cracks of significance are generally detectable, even in the tubesheet region,

*As discussed in NUREG-0523, "Summary of Operating Experience with Recirculating Steam Generators". However, the bases for continued operation presented in this document did not consider deep crevice corrosion as it was not identified as a significant mode of tube degradation prior to publication.

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with the improved sensitivity associated with the multi-frequency ECT probe. It is unlikely that the general attack (IGA) will penetrate completely through the tube wall without a loss of some wall material, and where significant loss of wall material occurs, it is generally detectable by the ECT.

Primary-to-Secondary Leak Rate Limits

The third level of protection involves limits on the primary to secondary leakage rate. These limits are established to assure that (1) the occurrence of leaks during normal operation will be detected and (2) corrective action will be taken before any individual through-wall crack becomes large enough to open up during postulated accident conditions and affect the ability of the ECCS system to cool the core during a LOCA or result in unacceptable radioactivity releases during a MSLB. For straight section tubes wih no radial restraint, a 0.35 gpm (500 gpd) limit assures that any individual through-wall crack is less than the critical flaw size which could burst under loads associated with postulated accident.

For through-wall cracks which may exist within the tubesheet, leakage during postulated accidents will be severely restricted by the tight annular region between the tube and tubesheet.

Mechanical Tube Integrity

Because of the nature of deep crevice cracking, the mechanical integrity of the degraded tubes offers an additional level of protection. Because the deep crevice cracking is peculiar to the local chemistry conditions in the tube to tubesheet crevice, the phenomenon will be limited to that area. This is confirmed by the location of all the defects which have been observed during inservice ECT inspection, and by the laboratory examinations and mechanical testing of tube samples removed from Point Beach Unit 1. The mechanical tests demonstrate that material beneath the depth of general grain boundary attack and crack penetration exhibit similar mechanical properties as the virgin material and is sufficiently ductile to allow the tube to expand to contact the tubesheet. Therefore, under MSLB, the constraint provided by the tubesheet eliminates the potential for tube burst.

Regarding postulated LOCA conditions, it is the licensee's conclusion that the tubesheet constraint against tube ovalization accompanying collapse reduces the possibility of collapse within the tubesheet. Independently simulated collapse tests were conducted on unrestrained tubes with defects as large as 75% to 80% wall thinning and 1.5 inches in length. The lowest collapse pressure observed in these tests is 1760 psi which is well in excess of the pressure differential expected during a LOCA. These tests indicate that tube collapse would not be expected during a LOCA. These independent test results can be extrapolated to envelop the conditions within the tubesheet region.

The independently simulated collapse tests resulted in small openings in the tubes which would have corresponding leak rates much smaller than would be expected from a burst tube. The secondary to primary in-leakage rate would be further limited by the restricted flow through the tube to tubesheet crevice. An NRC staff evaluation indicates that critical overheating of the fuel during a LOCA could only occur for leakage rates in excess of 1300 gpm. A large number of tube failures (collapses) would therefore be necessary before the secondary to primary leak rate would result in steam binding and adversely affect the ability of the ECCS to cool the core.*

Licensee's Proposed Bases For Continued Operation

The licensee has proposed a program to provide additional assurance of continued safety. This program includes (1) performing periodic primary to secondary hydrostatic tests to monitor the tubes' ability to maintain their integrity under various differential pressure loadings, (2) imposing a primary to secondary leak rate limit that is more restrictive than the current Technical Specification limit, (3) increasing the frequency of ECT inspections beyond that required by the Technical Specifications, and (4) adopting more restrictive reactor coolant activity limits.

The staff agrees that hydrostatic pressure tests prior to returning to power and periodically during operation will provide a positive indication and increased confidence in steam generator tube integrity. These tests are conducted in a quasi-static mode that adequately models postulated accident conditions. Similarly, the proposed decrease in the primary-to-secondary leak rate limit will provide conservative limits which will require timely plant shutdown and corrective actions. Inservice inspection by ECT techniques is intended to identify tubes which require plugging or are expected to require plugging prior to the next inspection. Therefore, the inservice inspection and tube plugging criteria are

*This is discussed in more detail in Appendix A of this SER.

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tied together by the margin left for continued degradation and by the rate of degradation. The decreased effectiveness of ECT in the tubesheet region, and the limited data base for defining the rate of corrosion indicate that more frequent inspections are necessary. Therefore, the staff is in agreement with the licensees proposal that ECT inspection of the steam generators should be conducted more frequently as described on page 16 of this SER. The increased frequency of inspection will ensure that tubes with large defects will be detected and removed from service and that the rate of degradation will be carefully monitored.

Measures for Reducing The Rate of Degradation

The licensee has also proposed various measures to be implemented in an attempt to retard further tube degradation. These measures include 1) a crevice flushing program to remove harmful chemicals from tubesheet crevices, and 2) reduced reactor coolant system operating pressure and temperature to reduce tube stresses and temperature.

Regarding the crevice flushing program, residual sodium and phosphate in the tubesheet crevice region will be removed by crevice-flushing techniques (i.e., a steam flashing technique to dissolve material in the crevice). This should help minimize further tube degradation in the deep crevice of the tubesheet.

Sodium, an alkaline forming species in boiler cooling water, is a principal element that causes intergranular corrosive attack of Inconel 600 alloy which leads to caustic stress corrosion cracking. Caustic stress corrosion cracking is dependent on temperature, hydroxyl-ion concentration and stress. Laboratory tests in NaOH solutions have shown that the time for stress corrosion cracking to occur in Inconel 600 alloy increases at temperatures below 550°F.

The licensee proposes to operate the Point Beach Unit 1 with a reactor coolant inlet temperature to the steam generators of 557 F with approximately a 10% reduction in pressure differential to reduce the stress level. The lower operating temperature will reduce the rate constant for intergranular corrosion. Also the lower stress levels will reduce the rate of crack growth. Operation of lower reactor coolant pressure (2000 psia) is currently under review by the NRC staff. The acceptability of this proposal will be addressed separately.

Regarding reduced reactor coolant system operating pressure and temperature, the only effect of the reduced temperature operation on the integrity of the major components will be a slight increase in the rate of radiation damage to the belt-line of the reactor vessel. This is expected to be a minor effect, but should be taken into consideration when evaluating the pressure-temperature limits in the technical specifications. On the basis of information available, it is estimated that the additional shift in RT_{NDT} would amount to about 50 F, if the lower temperature operation is continued to the end of life. Additional assurance that this effect will be properly evaluated will be obtained from the reactor vessel material surveillance program. The lower operating parameters are not expected to affect the design limit for steam quality; i.e. moisture carry over.

CONCLUSIONS

Based on the above evaluation, the staff has reached the following conclusions:

1. Eddy-current-testing cannot be relied upon to detect all deep-crevice corrosion degradation but the majority of the defects, particularly those that are significant, will be detected.

2. Hydrostatic pressure tests performed prior to and during operation will identify any significant remaining defects.

3. Conservative primary to secondary leak rate limits will provide assurance that in the event that large defects go undetected, or the corrosion rate accelerates, timely plant shutdown and corrective actions can be taken.

4. The constraint provided by the tubesheet and the mechanical properties of the tubes greatly decrease the probabilty of gross tube failure under normal operating or postulated accident conditions.

5. A maximum 60 effective full power day operating period prior to the next ECT inspection will provide adequate assurance that a large number of tubes will not simultaneously reach a point of incipient failure.

6. Remedial actions proposed by the licensee will mitigate the effects of postulated accidents and retard the rate of corrosion.

7. The condition that the plant will be shut down for ECT examination when two leaks are experienced in any 20-day period will provide an early indication of any accelerated degradation. This will add further confidence of steam generator tube integrity.

Finally, even if a few tubes went undetected by ECT and hydrotests, became severely degraded without leaking, and collapsed during a postulated LOCA, the resulting in-leakage would be tolerable because of the collapse failure mode and the large leak rates required to adversely affect ECCS performance.

Therefore, the staff has concluded that implementation of the remedial actions proposed by the licensee will assure safe operation of the unit for a conservatively established period of 60 effective full power days. At the end of this period an ECT inspection of the steam generators should be performed and results evaluated.

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APPENDIX A

CALCULATION OF SECONDARY-PRIMARY LEAKAGE

First addressing the out-leakage flow phenomenon the staff assumed a nominal crevice gap of 0.008 inch, the crack is located mid-depth (about 10 inches) below the top surface of tubesheet and primary-to-secondary Δp of 1500 psi, the leakage rate is calculated to be 9.5 gpm. Within 9 seconds of a LOCA, the pressure difference drops to zero psi primary-to-secondary, the leakage rate would then be zero. After this time the Δp reverses and the in-leakage takes place.

Under LOCA conditions that the in-leakage is of concern, this in-leakage rate is calculated to be 5.5 gpm under the following assumptions:

- Mass Flux G: 3800 lbm/ft^2 -sec
- Nominal Crevice Gap: 0.008 inch
- Saturation condition of secondary water at the maximum pressure difference of 800 psi.

In addition a conservative calculation was made which assumed guillotine tube rupture at .5 inches below top of tubesheet giving an in-leakage rate of 9.2 gpm. Based on the above two calculations, the in-leakage flow rate was estimated to be 7 gpm.

Therefore, a very large number of tubes has to be simultaneously broken in a guillotine manner to induce a large total in-leakage (>1300 gpm) to be of concern regarding the steam binding effect that may slow down the ECCS performance. Thus, the concern in the Wisconsin's Environmental Decade's Petition of November 14 and 26, 1979, regarding the APS study of steam binding is not an applicable concern in this case.

Further, these estimates are conservative in that the guillotine break has to be initiated from circumferential cracks which have not been observed, and the gaps are filled with sludge and not clean as assumed.

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APPENDIX B

ECCS Analysis for 18% Steam Generator Tubes Plugged

By letter dated November 19, 1979 (Reference 1), as supplemented November 26, 1979 (Reference 2), Wisconsin Electric Power Company (the licensee) submitted an Emergency Core Cooling System (ECCS) reanalysis for Point Beach Nuclear Plant, Unit 1. The analysis was performed assuming 18 percent of steam generator tubes plugged. It supersedes the previous ECCS analysis in which 10 percent of steam generator tubes were assumed to be plugged (Reference 3).

Evaluation

The recently experienced steam generator tube degradation required plugging of additional tubes and the level of the tubes plugged is now at the 10 percent limit assumed in the current ECCS analysis* (Reference 3). In order to allow for some additional tube plugging, the licensee has requested that the limit of steam generator tubes plugged be raised from 10 percent to 18 percent. In support of his request, the licensee has submitted a new LOCA analysis based on 18 percent of steam generator tubes plugged (Reference 1). The analysis was performed with the NRC approved February 1978 version of the Westinghouse Evaluation Model (References 4, 5, and 6) and it included the following assumptions:

Total Peaking Factor: 2.32
Primary Coolant System Pressure: 2280 psia
Core Inlet Temperature: 544°F (nominal value)

Although the submitted analysis was limited to a single break, the DEGCL with $C_D = 0.4$, the licensee has provided an acceptable justification by referencing

*10.1% in steam generator A; 9.8% in B.

the generic analysis which was performed for the whole break spectrum and which was previously submitted to the NRC (Reference 3).

The consideration of upper plenum injection (UPI) effect was not included in the present analysis. However, it was previously demonstrated (References 7 and 8) that this effect would cause a 60 F increase in peak clad temperature (PCT). In order to use the present ECCS evaluation model to analyze a postulated LOCA in the Point Beach plant and remain in compliance with 10 CFR 50.46, a limit of 2140 F on calculated peak clad temperature must be observed.

The results of the analysis are provided below:

Peak Clad Temperature: 2053°F

Local Zr-Water Reaction: 5.11 percent

Total Zr-Water Reaction: less than 0.3 percent

All these values are below the limits of 10 CFR 50.46 and are therefore acceptable.

Conclusion

Based on our review of the submitted documents, we conclude from the results of the ECCS analysis performed with the previously approved February 1978 version of the Westinghouse evaluation model that operation of Point Beach Unit 1 at a primary coolant pressure of 2250 psia and a peaking factor limit of 2.32 will be in conformance with the 10 CFR 50.46 criteria. We consider the ECCS analysis acceptable for allowing the plant to be operated with up to a maximum at 18 percent of steam generator tubes plugged.

References

1. Letter from Wisconsin Electric Power Company (S. Burstein) to NRC (H. R. Denton), dated November 19, 1979, transmitting: ECCS Reanalysis for 18% Steam Generator Tube Plugging Limit, Point Beach Nuclear Plant, Unit 1.

2. Letter from Wisconsin Electric Power Company (S. Burstein) to NRC (H. R. Denton), dated November 26, 1979.

3. Letter from Wisconsin Electric Power Company (S. Burstein) to NRC (H. R. Denton), dated March 20, 1979, transmitting: LOCA Reanalysis with 10% of Steam Generator Tubes Plugged, Point Beach Nuclear Plant, Units 1 and 2.

4. WCAP-9220-P-A, Westinghouse ECCS Evaluation Model, February 1978 Version, February 1978.

5. Letter NS-TMA-1981 from Westinghouse Electric Corporation (T. M. Anderson) to NRC (J. Stolz), dated November 1, 1978.

6. Letter NS-TMA-2014 from Westinghouse Electric Corporation (T. M. Anderson) to NRC (R. L. Tedesco), dated December 11, 1978.

7. Letter from Wisconsin Electric Power Company (S. Burstein) to NRC (E. G. Case), dated February 20, 1978.

8. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report on Interim ECCS Evaluation Model for Westinghouse Two-Loop Plants," March 1978.

APPENDIX C

REVISED REACTOR COOLANT ACTIVITY LIMITS

We have evaluated the potential radiological consequences of steam line breaks and steam generator tube ruptures for the Point Beach Unit No. 1 plant. The consequences of these accidents can be limited to small fractions of the 10 CFR 100 guidelines by appropriate limits on the fission product concentrations of the primary coolant. The present technical specifications do not include a specific limit on iodine concentration in the primary coolant. In response to the staff's request, the licensee has agreed to operate within the limits of the staff's Standard Technical Specification on primary coolant activity for Point Beach 1. With this Standard Technical Specification in place, we conclude that the consequences of postulated steam line break and steam generator tube rupture accidents would result in doses which would be a small fraction of the 10 CFR 100 guidelines.

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