UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
WISCONSIN ELECTRIC POWER COMPANY	)	Docket No. 50-301
(Point Beach Nuclear Plant,	)	
Unit 2)	)	(10 CFR 2.206)

DIRECTOR'S DECISION UNDER 10 CFR 2.206

By petition dated March 12, 1980, Wisconsin's Environmental Decade, Inc. (DECADE) requested that the Commission enter an order to show cause and an order enjoining operation of Point Beach Nuclear Plant, Unit 2, because of steam generator tube degradation at the facility. The petition was referred to the Office of Nuclear Reactor Regulation to be treated as a request for action under 10 CFR 2.206 of the Commission's regulations. Notice of receipt of the petition was published in the Federal Register on April 9, 1980 (45 F.R. 24293).

I

DECADE cites as the basis for its request previous filings dated November 14, 1979, November 26, 1979, December 17, 1979, January 8, 1980, and February 8, 1980. These earlier filings address the Petitioner's concerns regarding the consequences of a LOCA coincident with steam generator tube ruptures in light of significant tube degradation which has occurred at Point Beach Unit 1 within the tubesheet crevices and the more recent finding of defects at or slightly above the top of the tubesheet. 1/

DECADE contends that while it had previously been believed that no significant tube problem existed at Point Beach Unit 2, the experience at Unit 2

1/ The substantive issues raised in these filings have previously been addressed in Staff Safety Evaluations dated November 30, 1979 and April 4, 1980 for Point Beach Unit 1. See Attachments A&B.

on February 28, 1980 ("one tube ruptured with a leak rate reported at 1400 gpd") and subsequent eddy current test (ECT) inspections which identified 35 other tubes with defects, "all of which were above the tubesheet", invalidates any basis for continued operation of that facility.

The Staff has evaluated the steam generator tube leak which occurred at Point Beach Unit 2 on February 28, 1980, and the results of the subsequent steam generator inspection conducted at the facility during March 1980. For the reasons set forth in the attached Safety Evaluation Report, (Attachment C), and summarized below, I find that the Unit 2 steam generators have been adequately inspected and that the condition of the steam generators is adequate to assure continued safe operation of Point Beach Unit 2.

II

Unit 2 has previously experienced wastage and stress corrosion cracking at and above the tubesheet affecting in excess of 200 tubes, 2/ of which 36 had been plugged. As discussed in the attached SER, the Staff believes these defects to be in a generally stable condition, i.e., they are not developing at a significant rate. No special operating restrictions, such as those imposed at Point Beach Unit 1, have been required or imposed.

The 1400 gpd (gallons per day) primary to secondary leak which occurred recently at Unit 2 was a relatively small leak similar to those which have occurred at other PWR units as a result of through wall cracks. The term "rupture" is generally reserved for tube failures involving a sudden and violent opening of the tube generally accompanied by large plastic deformation and high leakage (e.g.,

---

2/ The Point Beach Unit 2 steam generators each contain 3260 U-tubes.

fishmouth tube burst). No tube ruptures have occurred at the Point Beach Unit 2 facility. 3/

The findings of the March 1980 steam generator inspection at Unit 2 are addressed in the attached Safety Evaluation. Deep crevice cracking at Point Beach Unit 2 is clearly at an early stage compared to the situation at Point Beach Unit 1 (and other units), and continued operation of Point Beach Unit 2 is supported by the evaluation and conclusions previously set forth for Unit 1 (see Attachment A). Should significant deep crevice cracking activity develop sometime in the future, the Staff would not expect this activity to occur above the top of the tubesheet. This is supported by results of laboratory examinations of five tube samples removed from Point Beach Unit 1 and one sample (containing the deep crevice indication) removed from Unit 2 indicating that the general intergranular attack occurring within the tubesheet does not extend outside of the tubesheet. The need for additional tube removals for laboratory examination will be considered by the Staff should the deep crevice cracking phenomenon continue to develop at Unit 2.

As discussed in the attached Safety Evaluation, the Staff has concluded that the finding of approximately 500 indications at the top of the tubesheet, including approximately 250 indications of 20% or greater, and 32 indications of 39% or greater, is not indicative of a new or highly active corrosion mechanism occurring at or above the tubesheet. This is supported by a reevaluation of eddy current tapes from previous inspections for those tubes containing 39% indications or greater indicating that the majority of these indications have been present

---

3/ A tube rupture (180,000 gpd) did occur at the Point Beach Unit 1 facility on February 26, 1975. That tube failure was determined to be the result of wastage and stress corrosion cracking above the tubesheet.

in previous inspections dating back to the period 1974 to 1977. Previous inspections dating back to this period have identified the region within a few inches of the tubesheet to be the scene of wastage thinning and/or stress corrosion cracking degradation which recent data indicates is not developing at a significant rate. The staff attributes the finding of the top of the tubesheet indications in March 1980 to the enhanced capability of multifrequency ECT to discriminate relatively small amplitude defect signals from the tubesheet entry signal, relative to previously employed single frequency ECT.

III

Based on the foregoing, I have determined that there is reasonable assurance that the Point Beach Unit 2 facility can continue to operate without undue risk to the public health and safety. Consequently, DECADE's request for an order to show cause and an order enjoining operation of the Point Beach Unit 2 facility is denied.

A copy of this decision will be placed in the Commission's Public Document Room at 1717 H Street, N.W., Washington, D. C. 20555 and in the Local Public Document Room at the Library of the University of Wisconsin, Stevens Point, Wisconsin 54481. Additionally, a copy of this decision will be filed with the Secretary of the Commission for review by the Commission in accordance with 10 CFR 2.206(c) of the Commission's regulations.

As provided in 10 CFR 2.206(c) of the Commission's regulations, this decision will constitute the final action of the Commission 20 days after the date of issuance, unless the Commission on its own motion institutes the review of this decision within that time.

Harold R. Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

Dated at Bethesda, Maryland
this 10th day of June, 1980.

Attachments:

A - Safety Evaluation Report Related to Point Beach Unit 1 Steam Generator Tube Degradation Due to Deep Crevice Corrosion - 11/30/79

B - Same Subject Report as Attachment A - 4/4/80

C - Same Subject Report as Attachments A & B

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

ATTACHMENT A

NOV 30 1979

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

dupe of 7912200079 33pp.

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 the various corrosion mechanisms that lead to 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 p ibly 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.

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, apparent reflecting improved control of sodium to phosphate (Na/PO_4) ratios and free causti 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.

Denting: - 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.

Deep Crevice Cracking: - 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.

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 EC 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 tube-sheet 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.

Mechanical Testing: - 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%.

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.

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 tube-

sheet 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.

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.

NOV 30 1979

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.

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.

ATTACHMENT B

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

April 4, 1980

dupe of
8004230017
17pp

INTRODUCTION

In accordance with the Confirmatory Order dated November 30, 1979, Point Beach Unit 1 was shutdown on February 29, 1980 for steam generator hydrostatic testing and eddy current inspection after having completed the authorized operating period of sixty (60) effective full power days (EFPD's) since the restart subsequent to the October 1979 steam generator inspection. The evaluation herein provides an update of the SER issued in support of the Confirmatory Order to reflect the operating experience at Unit 1 since the Order was issued, and the results of the steam generator inspection obtained during the February 29, 1979 outage. The background information and results of two consecutive inspections (August and October, 1979) as discussed in the November 30, 1979 SER are incorporated into this evaluation by reference.

BACKGROUND

CONFIRMATORY ORDER DATED NOVEMBER 30, 1979

Inservice inspections of the Point Beach Unit 1 steam generators performed during the August and October 1979 outages indicated extensive general intergranular attack (IGA) and stress corrosion cracking on the external surfaces of the steam generator tubes within the thickness of the tubesheet (generally referred to as "deep crevice corrosion"). In view of these findings and of the apparent high rate at which this corrosion phenomenon was developing, the licensee agreed to certain conditions to assure safe operation of Unit 1 for a period of sixty (60) effective full power days. This commitment was formalized by a Confirmatory Order dated November 30, 1979, amending the Operating License to include, in part, the following conditions:

1. a) Hydrostatic testing to be performed within 30 EFPD's.

   b) Hydrostatic testing and eddy current inspection within 60 EFPD's. Submittal of the proposed eddy current inspection program for NRC staff review. Eddy current inspection results also to be submitted, with no resumption of power until the Director, Office of Nuclear Reactor Regulation determines in writing that the results are acceptable.

2. More restrictive limits on primary to secondary steam generator leakage.

3. More restrictive limits on primary coolant activity.

4. Unit 1 not to be operated with more than 18% of tubes plugged in either of the steam generators.

While not covered under terms of the Confirmatory Order, the licensee implemented additional measures in an attempt to retard further tube degradation. These measures included 1) a crevice flushing program to remove harmful chemicals from the tubesheet crevices, 2) reduced operating temperature and pressure, 3) continued close surveillance of feedwater chemistry and condenser tube leakage, and 4) sludge lancing to be performed within 12 months of the return to power.

DEFECTS AT OR ABOVE TUBESHEET

The Safety Evaluation issued in support of the November 30, 1979 Confirmatory Order reflected the staff's understanding that the extensive degradation observed during the August and October 1979 inspections involved general intergranular attack and cracking within the tubesheet crevices, exclusively. Subsequent to the Confirmatory Order, however, the staff became aware of five (5) tubes with defect indications at or above the tubesheet which had not been addressed in the November 30 SER.

In response to our request, the licensee submitted by letter dated December 21, 1979 additional details regarding the defects in these five tubes and an evaluation of their significance. The licensee reviewed the single frequency eddy current test results since 1975 for the subject five tubes and compared the signals of these past inspections to the same frequency signal obtained during the multi-frequency inspection in October 1979. This comparison showed that the signals have not changed through three or four inspections since 1975. On the basis of this review the licensee concluded that the defects observed in October 1979 at or above the tubesheet have remained essentially unchanged since at least 1975 and occurred as a result of earlier thinning or cracking rather than to the intergranular attack phenomenon currently being experienced in the tubesheet crevice area and which was only first observed in November, 1977.

In response to our request, the licensee submitted by letter dated December 21, 1979 additional details regarding the defects in these five tubes and an evaluation of their significance.

Based upon our review of this submittal and a subsequent conference call with the licensee on December 22, 1979, we concluded that (1) the eddy current indications at or above the tubesheet, which were observed during the October 1979 inspection, are old defects, possibly due to wastage or stress corrosion cracking, which were active mechanisms in 1975 and earlier, (2) these indications are not related to the active phenomenon of general intergranular attack and cracking currently being experienced in the tubesheet crevices, and (3) the staff conclusions set forth in the November 30, 1979 SER remained valid and that the unit could continue to be safely operated under terms of the Confirmatory Order. Nonetheless, we have continued our investigation into the significance of the defects found at or above the tubesheet, particularly with regards to eddy current capabilities to detect these defects and their safety significance. This matter is addressed in further detail in this evaluation.

OPERATING EXPERIENCE SUBSEQUENT TO THE CONFIRMATORY ORDER

Following the issuance of the Confirmatory Order, Point Beach Unit 1 was returned to power on December 1, 1979. On December 11, 1979, Unit 1 experienced a rapid increase in primary to secondary leak rate, to 260 gpd, and was forced to shutdown under terms of the Confirmatory Order. The source of the leak was identified as one leaking tube and two leaking plugs in steam generator B. Although not required by either the Technical Specifications or the Confirmatory Order, the licensee performed multifrequency eddy current examinations in both the A and B steam generators. A total of approximately 1900 tubes were inspected. The inspection bounded all areas of previously observed deep crevice corrosion by at least one row and column of tubes. The inspection boundaries were expanded when new indications were observed

near the boundary. A set of randomly selected tubes outside the boundaries were also inspected. Representatives from the NRC staff and consultants were at the site on December 16, 1979 to observe the inspection in progress. As a result of this inspection, twenty (20) tubes were plugged in steam generator A and fifteen (15) tubes were plugged in steam generator B. None of the observed indications occurred at or above the top of the tubesheet. The inspection program and results were formally documented in Licensee Event Report 79-021/0IT-0 dated December 22, 1979.

Prior to resuming power operation, 2000 psid primary to secondary and 800 psid secondary to primary hydrostatic tests were performed. No tube failures or additional leakage resulted from these tests.

Based upon our review of the December 11 tube leak occurrence and the inspection results we concluded that the conclusions reached in the November 30, 1979, SER remained valid and that the operating restrictions imposed by the Confirmatory Order continued to provide adequate assurance of safe operation.

Point Beach Unit 1 was returned to power on December 22, 1979 and operated to the completion of its authorized 60 EFPD operating period (on February 24, 1980) with only a very minor, but equivalent to a constant 30 gpd primary to secondary leak. This was within the trace amount of equivalent leakage normally experienced at this unit.

MARCH 1980 INSPECTION RESULTS

FIELD EDDY CURRENT TESTING

The eddy current testing (ECT) program implemented during the March 1980 steam generator inspection was submitted for NRC staff review by letter dated February 26, 1980. This program was modified to incorporate NRC staff comments. ECT of 100% of the tubes in regions of previously observed deep crevice corrosion activity (including the kidney shaped central bundle region) was performed within boundaries bounding previously observed defects by at least one tube row and column. Where defects were observed to occur at the boundary, the inspection was expanded to bound these defectives by one tube row and column. An additional 3% random sample was inspected on the cold leg side and also among tubes on the hot leg side in areas not being 100% inspected. Representatives of the NRC staff were on site during the inspection to monitor the inspection as it proceeded, and to facilitate timely decisions from NRC/NRR regarding the need for additional inspection or tube pulling for laboratory examination.

Multifrequency eddy current testing (ECT) conducted in accordance with the approved program revealed 18 defect indications on the hot leg side in steam generator A and 24 defect indications on the hot leg side in steam generator B. In addition, 3 tubes in S.G. B and 6 tubes in S.G. A were found with undefinable indications within the tubesheet. On March 31, a hydrostatic test conducted after the ECT inspection revealed two tubes leaking at approximately 2 drips/minute and two wet plugs in S.G. B. Following plugging of these tubes and repair of the wet plugs a second hydrotest revealed another leaking tube in S.G. B which was plugged. Table I summarizes the ECT indicated defect depths in the two steam generators. Table II summarizes the elevation of the defect indications above the lower, primary surface of the tubesheet which is about 23 inches thick. Some defects affected several inches of tube length and one tube had indications running from the tube expansion at the primary surface of the tubesheet to approximately one inch below the upper, secondary tubesheet surface. The elevations indicated in Table II are the highest elevations reached by each defect.

TABLE I ECT INDICATED DEFECT DEPTHS		
DEFECT DEPTH IN PERCENT OF TUBE WALL	NUMBER OF TUBES	
	S.G. A	S.G. B
90 to 100	5	3
80 to 89	7	7
70 to 79	2	7
60 to 69	3	3
50 to 59	-	2
40 to 49	1	2

TABLE II ELEVATION OF ECT DEFECT INDICATIONS		
DISTANCE ABOVE THE PRIMARY TUBESHEET SURFACE (INCHES)	NUMBER OF TUBES	
	S.G. A	S.G. B
0-4	-	1
5-9	-	2
10-14	2	2
15-19	8	6
20-21	8	12
1/2" ABOVE SECONDARY T.S. SURFACE	-	1

No defective tubes were discovered outside of the central bundle region on the hot leg side nor anywhere on the cold leg side of either steam generator.

Tables I and II in Appendix I provide a tube by tube evaluation of ECT indicated defect depths and elevations and results of re-evaluations of ECT tapes from previous inspections for each defective tube. Study of these tables reveals that 15 tubes in steam generator A and 4 tubes in steam generator B had the same ECT indications but were overlooked in either the December or the December and October 1979 inspections. All of the tubes with defect indications were plugged except those that were removed for laboratory examination. All the ECT indications were of small amplitude and indicate very small volume defects.

TUBE PULLING AND LABORATORY EXAMINATIONS

In their February 26, 1980 submittal the licensee committed to remove a tube from the Unit 1 steam generators if one was found with an eddy current testing indicated defect at or above the top of the tubesheet, such as were observed in five tubes during the October 1979 inspection. The primary interest in removing this type of tube was two fold: (1) to determine if the intergranular attack occurring within the tubesheet crevices is resulting in tube degradation at or above the upper secondary surface of the tubesheet and (2) to correlate field ECT with laboratory examination of the defects. As indicated in Table II one tube was discovered in steam generator B with an indication approximately 1/2" above the top of the tubesheet. This was tube R19-C37 and the indication was 58% deep. In accordance with their commitment, this tube was removed from the steam generator for laboratory examination. In addition, the NRC (after a review of the ECT results) required removal of two other tubes for laboratory examination. These were tubes R30-C41 which had a 47% indication approximately 21" above the primary face of the tubesheet and tube R26-C53 which had a 86% indication approximately 18" above the primary face of the tubesheet. Removal of these tubes was intended to provide additional data regarding the extent and magnitude of IGA and the accuracy of ECT. The tube removal procedures extended the outage time approximately six days and resulted in approximately an additional 155 manrem exposure.

LABORATORY RADIOGRAPHY AND EDDY-CURRENT TESTING

Radiography and ECT were performed on all three of the removed tube specimens by Westinghouse at their Pittsburgh R&D facility.

As a result of the pulling process the original 22.1/2" length of tube R30-C41 within the tubesheet was elongated to approximately 24-3/4". This measurement was based on the ring left on the tube at the top of the tubesheet. Radiography of the removed tube revealed many defect indications in the region up to 23-1/4" from the tube end. Many ECT indications existed up to 23-1/2" from the tube end. No radiographic or ECT indications existed at or above the ring marking the top of the tubesheet.

The laboratory ECT examination indicated an approximately 70 to 80% defect based on evaluation of the single frequency (400 KHZ) signal, located 23-1/2" from the tube end. Based on the elongation caused in the tube removal process, 23-1/2" corresponds to approximately 21.3" from the tube end in the unstrained tube.

The field ECT indicated a 47% defect at 400 KHZ approximately 21" from the tube end. Field evaluation of the defect based on the multi-frequency signal estimated the defect depth in the same 70% to 80% range as obtained in the laboratory (at 400 KHZ) in the absence of tubesheet interference effects. Defect depths are reported based on the single frequency signal when possible since it is the technique currently approved by the ASME Code.

The pulling of tube R26-C53 elongated the original 22.5" of tube in the tubesheet crevice to approximately 25-7/16". Radiography of the removed tube revealed many defect indications in the region up to approximately 19.8" from the tube end as well as a single defect 25" above the tube end. Eddy current testing revealed many defect indications up to 19.8" from the tube end. Eddy current testing also revealed two 90% defects located approximately 7/16" and 2-7/16" below the tubesheet ring. No radiographic or ECT indications existed at or above the ring marking the top of the tubesheet.

None of the above laboratory ECT indications for tube R26-C53 were specifically identified in the field. Some of the indicated defects may have been introduced or made worse during the tube pulling operation. "Squirrel" indications (minor disturbances in the ECT signal of underterminable origin) were observed in the field over the full length of tube within the tubesheet. It was not possible to verify through laboratory ECT the 86% ECT indication observed in the field 18" above the tube end, since this corresponded to one of the locations where the tube broke during pulling. However, this field ECT indication will be compared with the results of the fractography analysis of the fracture surface as part of a detailed report which the licensee has committed to submit by April 30, 1980.

Tube R19-C37 was of particular interest because of the field ECT indication of a 58% defect located approximately 1/2" above the tubesheet. Unfortunately, when the tube was examined there was no ring clearly indicating the top of the tubesheet as there was on the other two tubes which were removed. Since the section of tube within the tubesheet experiences a different load and elongation during the removal process than the section of tube above the tubesheet, the exact location of the top of the tubesheet relative to the tube cannot be directly quantified.

Radiography and ECT of the removed tube revealed many defect indications in the region up to 23.75" from the tube end. Radiography also showed crack like indications approximately 24-3/8" above the tube end and ECT indicated an approximate 60% defect 24-1/2" above the tube end. No ECT indications were observed above the 60% indication.

Although the 60% laboratory ECT indication corresponds well with the 58% field ECT indication, its elevation cannot be directly correlated to the field indications because the location of the top of the tubesheet is not identifiable. Calculations based on strains in the other tubes which were removed indicate that this defect would have been inside the tubesheet. Nonetheless, it is the defect with the highest elevation in the tube, its depth corresponds well to the field ECT depth and it could be the defect of interest given the non-uniform straining of the tubes during removal.

Metallographic Examinations

Metallographic examination consisted primarily of photomicrographs (PM) to determine at what elevation IGA existed in the tubes.

For tube R30-C41 PMs were prepared for sections centered on the top of the tubesheet and approximately 0.35" below and 0.45" above the top of the tubesheet. In each of these regions PMs of 50 and 200 power magnification were made. The 200 power PMs were centered on the region in the 50 power photomicrographs indicating the greatest surface irregularities. For the section of tube below the top of the tubesheet the PMs showed shallow grain boundary separation on the order of 0.0025" maximum. At the top of the tubesheet, shallow surface separation was observed affecting grain boundaries to just over 0.001" in depth. Similarly above the top of the tubesheet surface separation of the grain boundaries was observed to a depth of approximately 0.001 inches. Extensive general IGA as is occurring deeper in the tubesheet crevice was not observed in any of these regions.

Photomicrographs were also prepared for tube R26-C53. Again the PMs were centered about the top of the tubesheet and approximately 0.4" below and 0.2" above the top of the tubesheet. The section below the top of the tubesheet showed shallow grain boundary separation penetrating approximately 0.002" maximum.

The region centered about the top of the tubesheet showed no grain boundary separation although some surface irregularities penetrating less than 0.001" existed. Above the top of the tubesheet some areas of grain boundary separation penetrating approximately 0.003" were observed. Extensive general IGA as is occurring deeper in the tubesheet crevice was not observed in any of these regions.

Five photomicrographs were made of tube R15-C39. One was centered on the 60% defect described earlier while the other four were centered approximately 1-5/8" and 3/4" below and 1" and 1-3/4" above the defect. The two sections below the defect showed IGA penetrating to depths of nearly 0.004". Photographs of the tube surface at the defect show a crack running less than approximately 1/2" longitudinally then turning and running less than approximately 1/4" circumferentially. Photomicrographs of a section made through the defect show a crack penetrating approximately 0.017" surrounded by localized IGA. The longitudinal section made for the PM may not have included the deepest section of the crack. Section D above the defect indicates one localized area of grain boundary separation approximately 0.001" deep and section E above the defect shows no grain boundary separation but some shallow surface irregularities less than 0.001" in depth.

PROPOSED CONDITIONS FOR CONTINUED OPERATION

The licensee has proposed the following conditions to allow continued operation of Point Beach Unit 1.

1. Within 90 EFPD, a 2,000 psid primary-to-secondary hydrostatic test and a 800 psid secondary-to-primary hydrostatic test will be performed. An eddy current examination consisting of about 1,000 tubes in the central region of the hot leg in each steam generator and 3% of the remaining tubes outside this area will be performed.

2. Primary coolant activity for Point Beach 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.

3. Close surveillance of primary-to-secondary leakage will be continued and the reactor will be shutdown for tube plugging on confirmation of any of the following conditions:

a. 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 (average over a three-day period) in primary-to-secondary leakage in either steam generator in excess of 15 gpd (0.01 gpm) per day, when measured primary-to-secondary leakage is above 150 gpd in that steam generator.

4. The reactor will be shutdown, any leaking steam generator tubes plugged, and an eddy current examination as described in Item 1., above, will be performed if leakage due to crevice corrosion in either steam generator exceeds the limits stated in Technical Specifications 15.3.1.D.

5. Unit 1 will be operated at a reactor coolant pressure of 2,000 psia with the associated parameters (i.e., overtemperature ΔT and low pressurizer pressure trip point) with the limits indicated in the Safety Evaluation Report appended to your letter of January 3, 1980.

On return to power operation, the licensee proposes to continue the following program to assist in retarding further tube degradation:

a. Unit 1 will be operated at a reduced reactor coolant system hot leg temperature.

b. Continue close surveillance of feedwater chemistry conditions and condenser tube leakage.

c. Perform sludge lancing within nine months of returning to power.

EVALUATION

ECT PROGRAM, RESULTS, AND CAPABILITIES

Members of the NRC staff and their consultant from Oak Ridge National Laboratory were on site during the inspection to review the testing and evaluation techniques.

Eddy current testing examinations were conducted in accordance with the program proposed in the licensee's February 26, 1980 submittal and approved, with comment, by the NRC. This program bounded the areas where deep crevice corrosion was previously observed and was expanded in any areas where new indications were found. The random inspection of peripheral hot leg tubes and cold leg tubes revealed no deep crevice corrosion. Therefore, the inspection performed is adequate to ensure that the great majority of tubes with deep crevice corrosion have been removed from service by plugging.

The March 1980 ECT results show a marked reduction in the number of tubes with indicated defects compared to the August and October 1979 inspections. In addition, fifteen of the 24 ECT indicated defects in steam generator B and 6 of the 18 ECT indicated defects in steam generator A were shown to exist previously through re-examination of the ECT tapes from previous inspections. Thus, the number of new defects discovered in this inspection is smaller than the raw data indicates. The inspection results suggest that some of the remedial actions taken by the licensee following the October 1979 inspection, particularly the lower temperature operation, may be succeeding in retarding the rate of further deep crevice corrosion, especially since the time of the December 1979 outage.

As discussed in our November 30, 1979 SER the accuracy of the eddy current 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 IGA, but which do not contain cracks. Partially through wall cracks of significance are generally detectable, even in the tubesheet region, with ECT. As experience has shown, however, very small volume defects which in turn produce very small amplitude ECT signals may be easily overlooked (as was the case with the 19 tubes above). Our evaluation of the safety significance of IGA and stress corrosion cracking occurring within the thickness of the tubesheet is discussed in our November 30, 1979 SER which is incorporated into this SER by reference.

With regard to the tubes observed during the October and March inspections to contain defects at or slightly above the top of the tubesheet, we have concluded that multifrequency ECT can detect defects of a significant size to threaten tube integrity during normal or postulated accident conditions. All of the defects discovered at or above the top of the tubesheet are small amplitude, small volume defects. Assuming the defects at or above the tubesheet to be wall thinning (wastage related), rough estimates of the size of the defects were made by the staff based on comparison with the ECT signatures from the ASME Code calibration standard. These estimates show that if these defects are wastage related, the volumes of these defects are very small compared to what is necessary to burst or collapse the tube under postulated accident conditions, as determined by independent tests sponsored by NRC (NUREG/CR-0718).

In the case of tube R19-C37 which exhibited a field ECT indication of 58% approximately 1/2 inch above the tubesheet, the laboratory examination indicates that the defect indication observed in the field is most likely a crack. NRC sponsored burst and collapse tests (NUREG/CR-0718) have been performed on free standing tubes with EDM notches (simulating a crack) of up to 85-90% (through wall) in depth. The results indicate the lower bound burst strength to exceed the maximum primary to secondary pressure differentials during normal operation or postulated accidents for notches (cracks) ranging to about 1 inch in length. It should be noted that the burst strength of a tube containing a crack defect slightly above or below the top of the tubesheet is considerably higher than for free standing tubes, because of the restraint against radial expansion of the tube provided by the tubesheet. The above tests indicated a collapse failure to be a much less limiting failure mode than a burst failure mode for free standing tubes during postulated accidents. Cracks of sufficient size to cause a burst or collapse failure under postulated accidents are considered by the staff to be well within the detectable capability of the multifrequency eddy current technique, regardless of the location of the crack relative to the top of the tubesheet.

Tube Removal and Laboratory Exam

Laboratory radiography and ECT confirm the position taken by the staff that general IGA may not be detectable in the crevice of the tubesheet until it is severe enough for preferential crack growth to occur. Detection of defects below the top of the tubesheet by laboratory examinations is due partly to increased capability of ECT without the influence of the tubesheet and partly to the creation of new or the opening of old defects during the removal process. Laboratory radiography and ECT confirmed the absence of defects above the tubesheet in tubes R30-C41 and R20-C53. Unfortunately the top of the tubesheet could not be identified on tube R19-C37.

However, assuming that the upper most defect detected in the tube is the defect which was identified by field ECT, there is a good correlation between the laboratory and field ECT. More importantly, the defect which was detected was small enough so as not to jeopardize tube integrity. Primary-to-secondary and secondary-to-primary hydrostatic tests conducted on March 6 revealed one tube (R23-C44) which exhibited a slight leak at a rate of 3 drips per minute, and one wet plug in a previously plugged tube (R23-C50) both in S.G. B. No tube ruptures occurred. The defect found by ECT just above the tubesheet in tube R19-C37 in S.G. B withstood the simulated accident pressure differentials. This provides additional support to our previously stated conclusion that multifrequency ECT can detect defects at or above the top surface of the tubesheet which would jeopardize tube integrity during normal operating or postulated accident conditions.

The staff wants to emphasize that as inspection techniques with increased capabilities, such as multifrequency ECT, are developed, that many small volume defects which previously went undetected will now be found. These defects must be evaluated in the context of the magnitude of defects which jeopardize tube integrity during normal or postulated accident conditions. As inspection techniques become more capable, correspondingly more discriminate criteria must be established. Many plants which have not been inspected with multifrequency ECT are going to show new defects when multifrequency inspections are performed. These results must be dealt with rationally and requirements for tube inspection, plugging, and removal must be carefully applied.

METALLOGRAPHIC EXAMINATIONS

Members of the NRC staff and their consultant from Brookhaven National Laboratory met with representatives from WEPCO and their Westinghouse consultants in Pittsburgh on March 28, 1980 to review results of the metallographic examinations. Review of the photomicrographs described earlier revealed no general IGA similar to that occurring within the tubesheet crevice above the top of the tubesheet in tubes R26-C53 or R30-C41. Shallow grain boundary separation on the order of two grains or less existed on all photomicrographs of these tubes. Shallow grain boundary dissolution of this nature can result from several mechanisms including previous operating environments or tube pickling during manufacturing. This grain boundary separation is much less severe than that occurring within the tubesheet. The staff has concluded that the shallow grain boundary dissolution at and above the top of the tubesheet is not significant in terms of tube integrity. Metallographic examination of tube R19-C37 revealed stress corrosion cracking and shallow IGA of the tube near the top of the tubesheet. Re-evaluation of past ECT tapes showed that this defect existed as far back as 1976 but was overlooked using single frequency ECT. The nature of the crack is similar to that of stress corrosion cracks which occurred during previous operating periods. The staff believes that this is an old defect which has not significantly changed since 1976.

CONCLUSIONS

Based on the information presented above the staff has reached the following conclusions:

1) The inspection and tube plugging performed has been adequate to ensure the great majority of defective tubes have been removed from service.

2) Multiple frequency eddy current testing used to perform the inspection is capable of detecting defects near the tubesheet and tube support plate interfaces which would jeopardize integrity of the tube during normal operation or postulated accident conditions.

3) Hydrostatic tests simulating postulated accident conditions performed prior to returning to operation will identify any significant defects overlooked during ECT examination.

4) Intergranular attack at and above the top of the tubesheet as observed in the removed tube samples is extremely shallow and poses no threat to tube integrity at or above the top of the tubesheet.

5) Based on the number of new defects, the rate of deep crevice corrosion appears to have decreased.

6) A maximum 90 effective full power day operating period, prior to the next ECT inspection as proposed by the licensee, will provide adequate assurance that a large number of tubes will not simultaneously reach a point of incipient failure.

7) Remedial actions proposed by the licensee will continue to mitigate the effects of postulated accidents and retard the rate of corrosion.

The staff has determined that the following conditions should be required for continued operation:

1) Within 90 effecting full power days from the date of this order, a 2,000 psid primary-to-secondary hydrostatic test and 800 psid secondary-to-primary hydrostatic test shall be performed. Also during this plant outage, an eddy current examination shall be performed on tubes in each steam generator. The program shall require such examinations of about 1000 tubes in the central region of the hot leg, three (3) percent of all hot leg tubes outside this central region and 3% of the cold leg tubes. The Central region shall encompass all areas where deep crevice corrosion has previously been observed.

2) 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 appended to License DPR-24.

3) 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.

4. The reactor will be shut down, any 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) Any two identified leaking tubes in any 20 calendar day period.

   This eddy current program will be as described in item 1.

5. The NRC Staff will be provided with a summary of the results of the eddy current examination performed under items 1 and 4 above. This summary will include a photograph of the tubesheet of each steam generator which will verify the location of tubes which have been plugged.

6. The licensee will not resume operation after the eddy current examinations required to be performed in accordance with condition 1 or 4 until the Director Office of Nuclear Reactor Regulation has determined in writing that the results of such tests are acceptable.

These conditions are similar to those in the November 30, 1979 Order except that the approved operating period has been lengthened from 60 to 90 effective full power days, and no shutdown to perform hydrostatic tests are being required prior to the end of the 90 day period. These conditions differ from the licensees proposal in that the primary to secondary leak rate limits and requirements for ECT examination are more conservative.

On the basis of our review and evaluation, we conclude that continued safe operation of Point Beach Unit 1 may be permitted within the stated terms of the Confirmatory Order.

APPENDIX I
TABLE I

POINT BEACH #1 'A' S/G

Tube # R	C	% 1980	M.F. Dec. 1979	M.F. Oct. 1979			
12	19	80% 19-21" ATE	SAME R251 No change	SAME R651 N.C.			
7	22	29%/96% 12"ATE/17"ATE	SAME R251 N.C.	NDD/SAME 12"ATE/17"ATE R551			
18	22	66% 12-17" ATE	SAME R251 N.C.	NDD R551			
10	23	41% 20" ATE	NDD R251	R551			
7	24	83% 17"-20" ATE	MAYBE(?) NDD R251	NDD R551			
8	24	79% 17"-21" ATE	MAYBE(?) NDD R251	NDD R551			
25	45	69% 12"-20" ATE	Squirrels P351	NDD R851			
20	48	85% 21" ATE	SAME R251 N.C.	SAME R851			
9	49	90% 21" ATE	NDD R251				
17	50	85% 19" ATE	NDD R251				
19	50	97% 11" ATE	NDD R251				
20	50	97% 11" ATE	NDD R251				
12	59	87% 21" ATE	MAYBE(?) NDD R151	NDD R951			
12	61	83% 17" ATE	NDD R151				
14	63	83% 19" ATE	MAYBE(?) Squirrels R151				

POINT BEACH #1 'A' S/G

Tube # R	C	% 1980	M.F. Dec. 1979	M.F. Oct. 1979			
15	66	60% 18" ATE					
8	27	Squirrels 15-20" ATE	SAME R251 N.C.				
15	28	Squirrels 21" ATE	No Squirrels R251				
28	34	Squirrels 18-21" ATE	SAME R251 N.C.				
28	35	Squirrels 17" ATE	SAME R251 N.C.				
20	41	91% 19" ATE	NDD R351				
25	43	73% 17" ATE	SAME R351	Very S.V. N.D.D. R751			
11	46	Squirrels 12"-21" ATE	SAME R351				
29	52	Squirrels 14" ATE	SAME R151 N.C.				

APPENDIX I

TABLE II

B S/G INLET POINT BEACH #1

Tube # R	C	% 1980	M.F. Dec. 1979	M.F. Oct. 1979	S.F. Aug. 1979		
18	26	75% 18" ATE	SAME R151 No change	Changed R651	NDD R551		
13	26	73% 21" ATE	SAME R151 N.C.	SAME R651 N.C.	NDD R551		
13	33	71% 20" ATE	SAME R151 N.C.	Changed R651	NDD R552		
6	24	91% 11" ATE	SAME R151 N.C.	SAME R651 N.C.	NDD R552		
20	35	68% 21" ATE	SAME R151 N.C.	Changed R351	NDD R552		
8	37	89% 5" ATE	NDD R151				
19	37	58% 1/2" ATS	SAME 53% R151 N.C.	SAME R351 N.C.	NDD R552		
10	41	70% 21" ATE	SAME R251 N.C.	NDD R751	R651		
30	41	47% 21" ATE	SAME R251 N.C.	Some Change R751	NDD R651/R151		
30	42	48% 21" ATE	SAME R251 N.C.	Changed R751	NDD R151		
22	46	76% 15" ATE	SAME R251 N.C.	NDD R351			
24	48	84% 12" ATE	Changed R251	NDD R351	R652		
30	48	85% 21" ATE	SAME R251 N.C.	SAME R951 N.C.	NDD R652		
25	49	84% 5" ATE	Changed R251	NDD R351	R652		
20	51	99%(?) 16" ATE	SAME R251 N.C.	NDD R351	R652		
23	54"	86% Full length	Squirrels some are new R251	SAME AS DEC. R351			

B S/G INLET POINT BEACH #1

Tube # R	C	% 1980	M.F. Dec. 1979	M.F. Oct. 1979	S.F. Aug. 1979		
23	57	56% 17" ATE	NDD R251				
21	58	83% 21" ATE	SAME R251				
14	59	75% 21" ATE	NDD R251				
21	63	62% 21" ATE	SAME R351	NDD R1051			
12	67	66% 21" ATE	NDD R351	R1051			
2	72	92% Top of Roll	SAME R351 N.C.	NDD R1051			
26	53	26% (New) 18" ATE					
30	43	Squirrels 21" ATE	SAME R251	SAME R751			
26	53	Squirrels Full T.S.	NDD R251				
25	55	Squirrels Full T.S.	NDD R251				
22	63	Squirrels 21" ATE	SAME R251	SAME R1051			
22	64	Squirrels 20" ATE	SAME R351	No Squirrels R1051			
25	55	74% (New) 15" ATE					