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ASSESSMENT OF TMI-1 PLANT SAFETY
FOR RETURN TO SERVICE AFTER
STEAM GENERATOR REPAIR
TOPICAL REPORT
008
REV. 3

PROJECT NO: 5000 51712

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I. INTRODUCTION

A. Purpose

In November 1981 primary to secondary side leaks were discovered in both TMI-1 Once Through Steam Generators (OTSG). Subsequent detailed failure analysis showed that extensive circumferential cracking had occurred in the OTSG tubes. This safety evaluation describes the results of the failure analysis, the evaluation of the methods of repair, and the operational, safety and environmental impact of operating the repaired generators.

B. Background

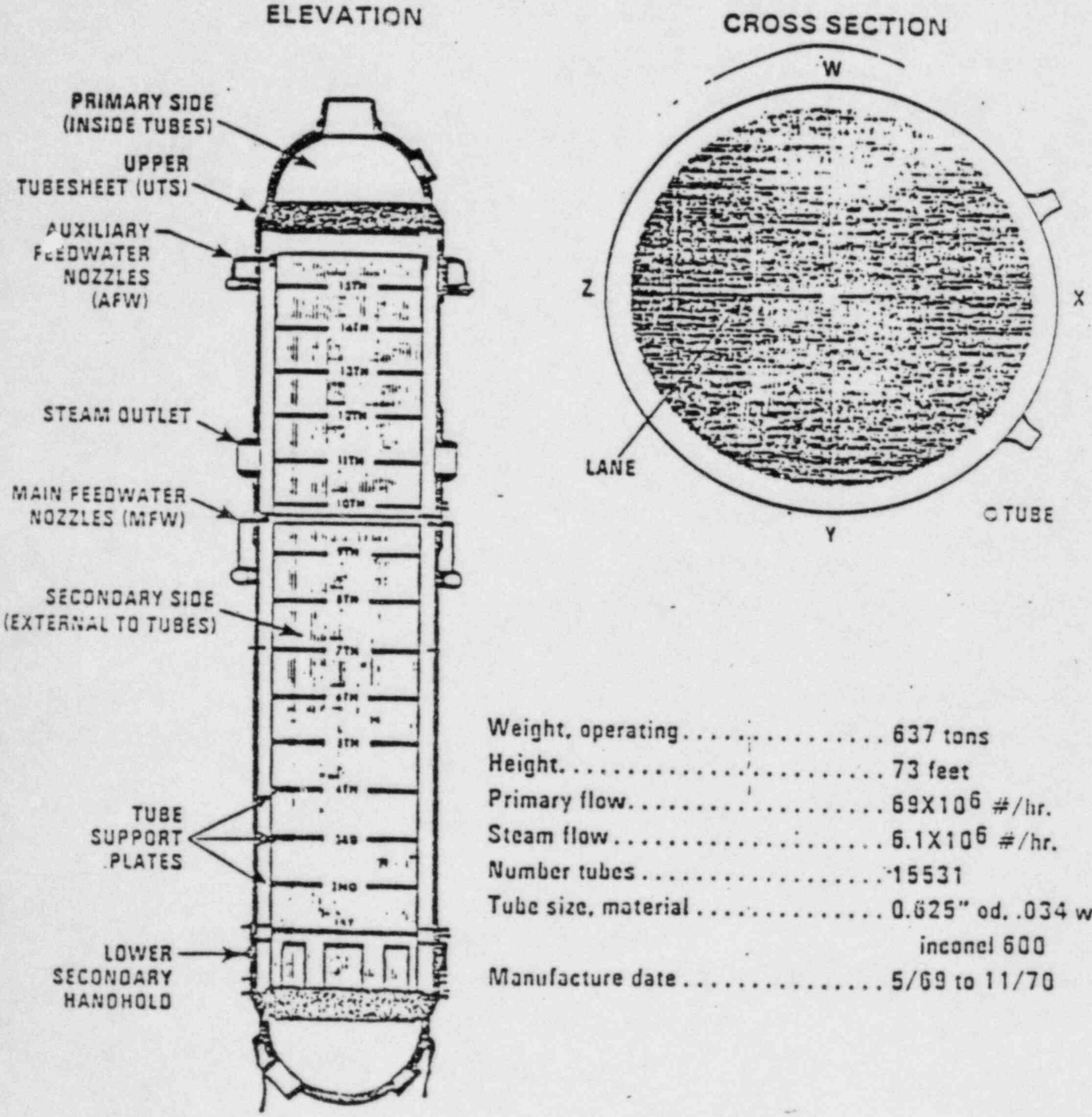
TMI-1 is a 776 MWe pressurized water reactor having two vertical, straight tube and shell once-through-steam generators (OTSGs). Each OTSG contains 15,531 Inconel-600 tubes, 0.625 in. OD, .034 in. wall, 56 ft. 2-3/8 in. long, rolled and sealed-welded into 24 in. thick carbon steel tube sheets at the top and bottom of the OTSGs. (See figure I.1)

The plant was shut down early in 1979 for refueling and has remained in the cold shutdown condition since the TMI-2 accident at the direction of the NRC. In anticipation of bringing the unit critical and returning to service, hot functional tests were performed in August-September 1981 and did not indicate any problems with the OTSGs. However, in November 1981, during pressurization for additional tests, primary to secondary leaks were detected in the OTSGs.

As soon as GPU Nuclear Corporation realized the extent of damage to the TMI-1 steam generators in early December, 1981, a dedicated OTSG task organization was established to coordinate the repairs of the steam generators. The structure of this task organization is shown on Figure I-2. The scope of the task organization included determining the cause of damage to the steam generators, defining the status of the steam generators in terms of what type of damage and at what locations, evaluating the numerous repair options and implementing the one chosen, evaluating the effect of the repair on both OTSG and plant performance, and establishing whether or not additional TMI-1 components had been damaged by the aggressive environment which was apparently created in the once-through steam generators. An internal safety evaluation was performed which included these areas. Throughout the entire OTSG repair program, GPU Nuclear Corporation made every effort to obtain the advice and counsel of experts throughout the utility, manufacturing, and research communities. As ca- be seen by reviewing the task organization on Figure I-2, the organizations and companies involved in defining the status of the steam generators and assisting in their repair cover a broad range of expertise.

FIGURE I-1

TMI-1 Steam Generator



Weight, operating	637 tons
Height	73 feet
Primary flow	69×10^6 #/hr.
Steam flow	6.1×10^6 #/hr.
Number tubes	15531
Tube size, material	0.625" od, .034 wall inconel 600
Manufacture date	5/69 to 11/70

OTSG TASK ORGANIZATION

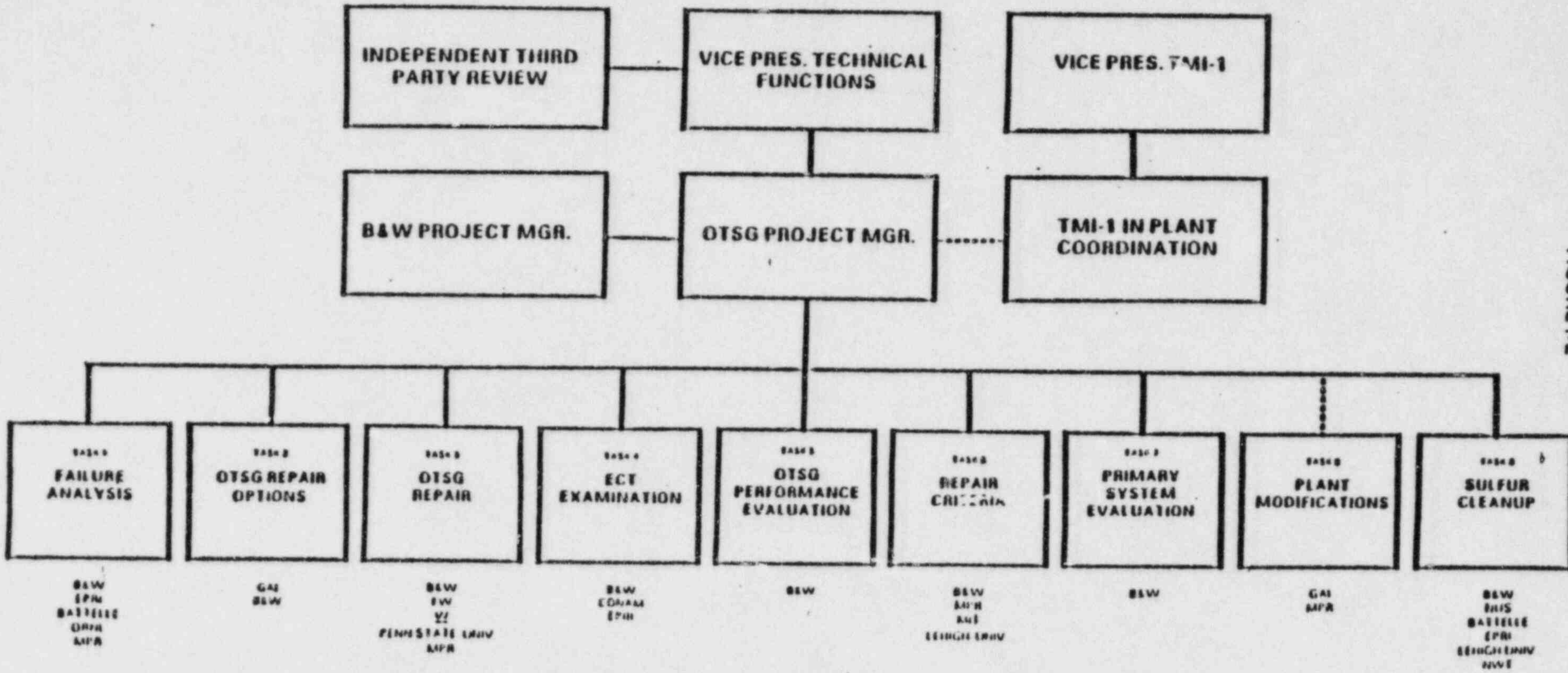


FIGURE I-2

In order to provide added assurance that the TMI-1 OTSG repair was conducted in a prudent, safe and technically correct manner, an independent third party review was established made up of experts from throughout the utility and research industries. This independent third party reported directly to the Vice-President of Technical Functions and was tasked to provide an independent and objective safety evaluation of the failure analysis program, eddy current examination program, OTSG performance evaluation, OTSG repair criteria, and the overall OTSG repair program. The advice and recommendations provided by this third party review have proven very beneficial. Their participation provides added assurance that the OTSG repair activities both conform to the NRC rules and regulations governing the operation of TMI-1 and assurance that the adequacy of the steam generator repair program allows safe operation of the TMI-1 nuclear unit.

C. <u>Steam Generator Repair Program</u>

The approach taken to restore the Steam Generators to service as to evaluate the condition of each tube with eddy current techniques developed specifically for the geometry of this corrosion mechanism. Following ECT the status of each tube was evaluated and one of the available repair methods was chosen.

Figure I-3 summarizes the disposition of all the tubes in the TMI-1 Steam Generators after repairs have been completed. This figure indicates the four methods of disposition, the basis for selecting those methods and some other concerns that were considered and resolved in selecting those methods.

The first category includes the tubes removed from service prior to the repair. These are tubes that have been previously plugged due to indications of defects from ECT inspections from previous operating cycles. Also included in this category are those tubes which had sections removed from the steam generator for metallurgical examination and those tubes which indicated leakage during the initial tests after damage was discovered.

The second category is the primary repair method for the steam generators. This repair method for the TMI-1 OTSGs involves expanding and resealing the existing tube walls within the upper tubesheet at points below where the cracking of the tubes occurred. The expansion closes the gap between the tubes and the tubesheet. The expansion is done kinetically using explosives (detonating cord) encased in a polyethylene insert (see Figure I-4). The insert transmits the explosive energy to the tube wall causing an interference pressure between the tube and the tubesheet.

The tube expansion repair method is feasible because of the specific nature and location of the cracking in the TMI-1 Steam Generator tubes. The majority of the cracking is located in the

DISPOSITION OF TUBES IN TMI-1 STEAM GENERATORS

31,062 TUBES TOTAL

	347	20775	857	83
	removed from service prior to repair	with no known defects below US + 8 repaired by expansion	with defects below US + 8 repaired by plugging	OD/ID indications < 90°, < 40% TW below US + 8, repaired by expansion
Basis for Disposition	-defects from previous inspections or -removed for metallurgical examination or -leaked during initial leak tests	-expansion joint qualified to design basis -ECT did not detect cracks below US + 8	-plugging methods qualified -safety analysis justifies operations with up to 1500 plugged tubes	-cracks will not propagate by mechanical loads during operation -ECT calibration program demonstrates detectibility 40% TW
Resolution of other safety concerns		-ECT calibration program demonstrated detectibility of < 40% TW cracks -cracks below 40% TW will not propagate by mechanical loads -any through-wall cracks below repair which were missed during inspection program will leak during test program -long and short term corrosion tests demonstrated that local IGA is not a concern and that cracks will not propagate by corrosion mechanism -precautions taken which will prevent new crack formation	-effects on EFW flow and natural circulation evaluated as adequate	-cracks will not fail during MSLB -highly reducing conditions at temperature prevent chemical propagation

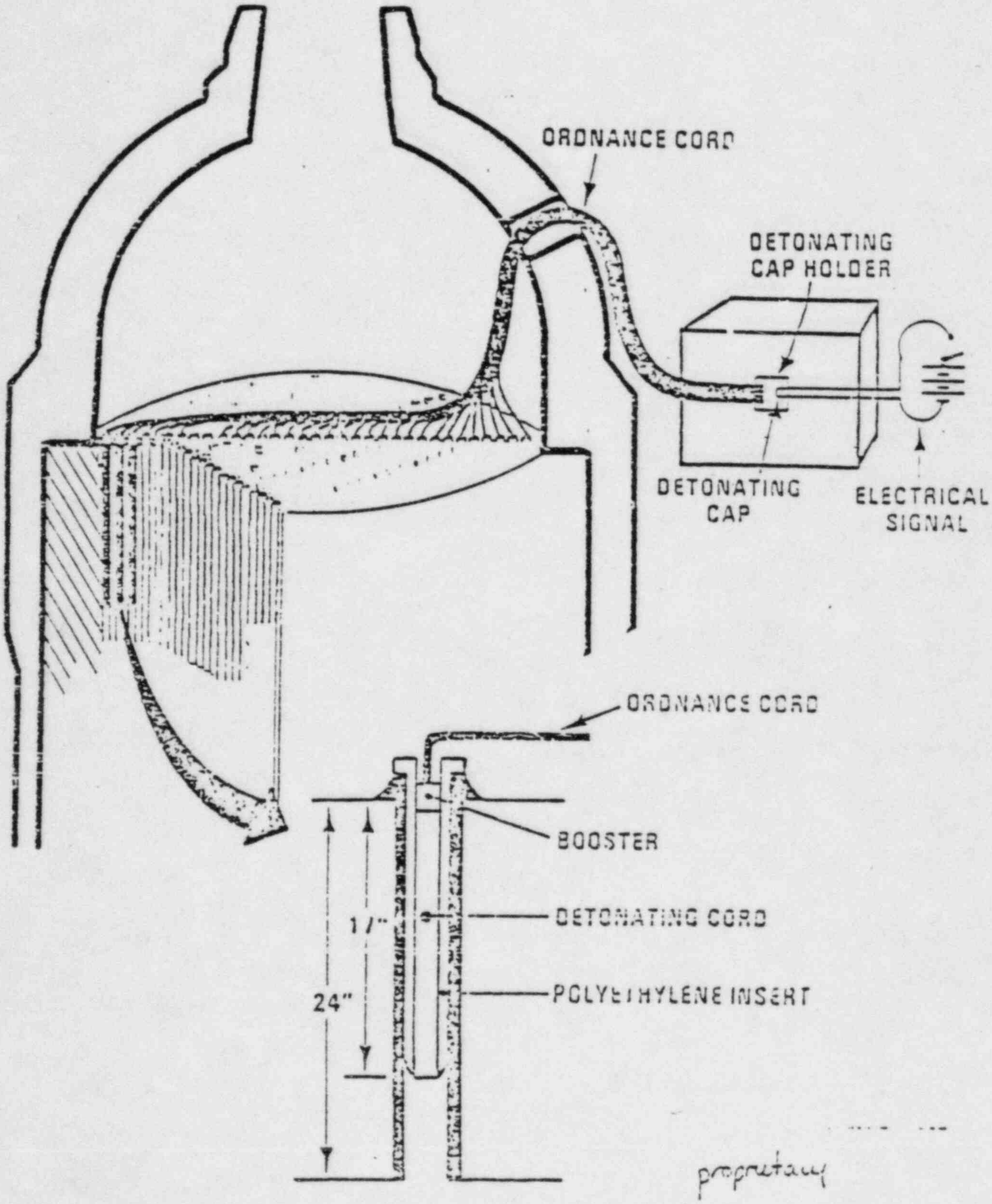
857
83
347
1287

857
83
774

FIGURE 1-3

FIGURE 1-4

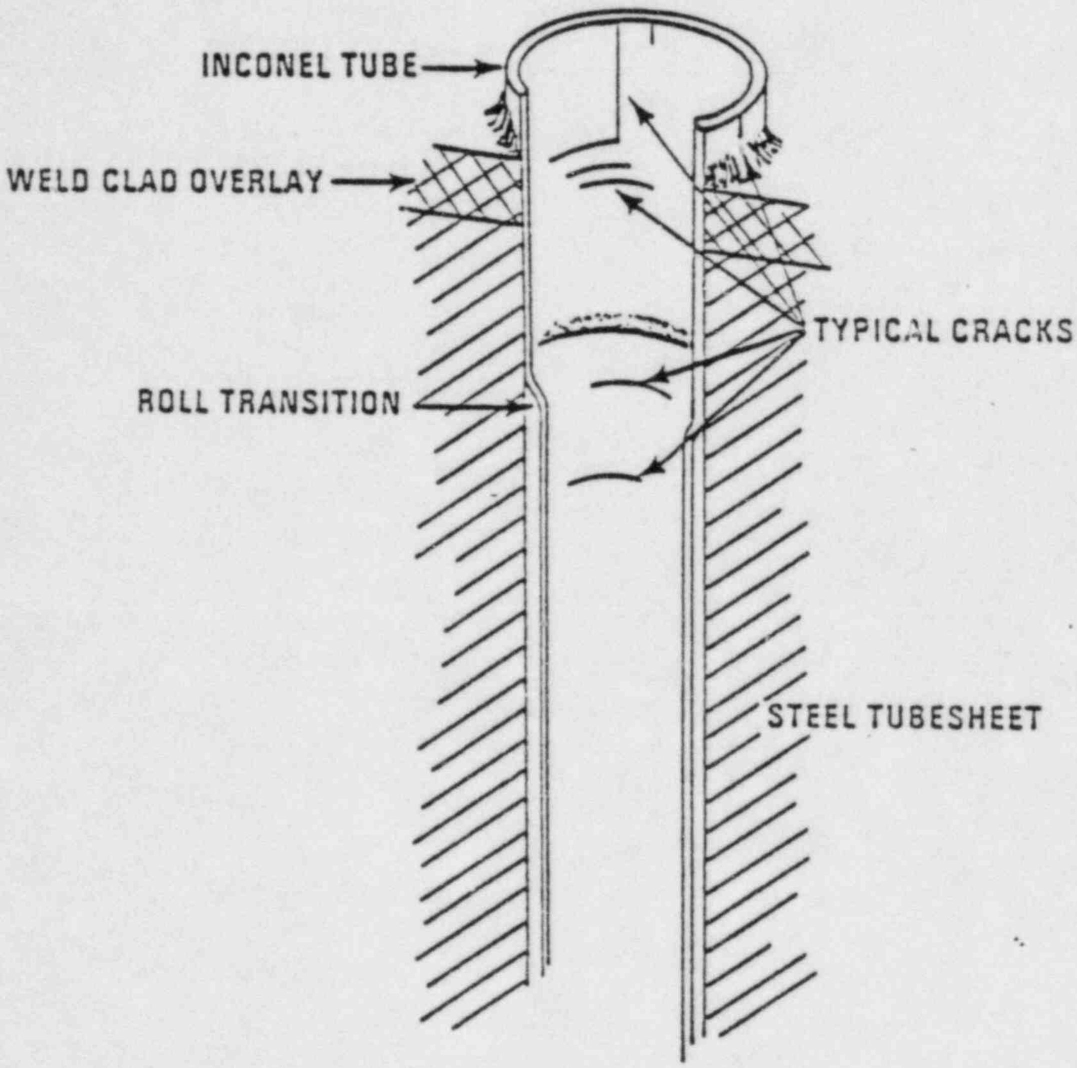
KINETIC EXPANSION PROCESS



proprietary

FIGURE I-5

TMI-1 Steam Generator Typical Cracks



CRACK CHARACTERISTICS: CIRCUMFERENTIAL BELOW FILET WELD
NOT FULL ARC
GENERALLY VERY TIGHT
PRIMARY SIDE INITIATED

upper ends of the tubes of the two generators, at or near the upper 1 in. to 1.5 in. where the 56 ft. long tubes were mechanically rolled and then seal welded to the tube sheet cladding (see figure I-5). The combination of rolled joint and seal weld held the tubes tightly in place within the tubesheets.

At TMI-1 both 17 in. and 22 in. long expansions will be utilized depending on the axial location (within the upper tubesheet) of the lowest defect. The expansion length is chosen to provide the minimum length necessary between the lowest defect and the bottom of the expansion to serve as the new pressure boundary. This expansion length corresponds to eight inches above the lower face of the upper tubesheet (US+8). This length provides the dividing line between those tubes with defects which could be repaired by expansion and those that would be removed from service. For the TMI-1 OTSG geometry and materials, a 6 in. long joint below the lowest defect has been shown to provide adequate leak tightness and load carrying capability and is the basis for the joint qualification program. All tubes that remain in service will be kinetically expanded irrespective of whether or not a defect has been detected. (see Figure I-6).

The third category includes those tubes which cannot be repaired by expansion due to unacceptable defects in the region below eight inches above the lower face of the upper tube sheet. These tubes will be removed from service by plugging.

The final category are those tubes with ECT indications that are less than 40% through wall. Since analysis indicates that these tubes will not fail by mechanical, thermal and accident loads, they are being left in service to provide characterization of these indications after they have been exposed to operation. Leaving this category in service provides information in future ECT inspections of the stability of these indications.

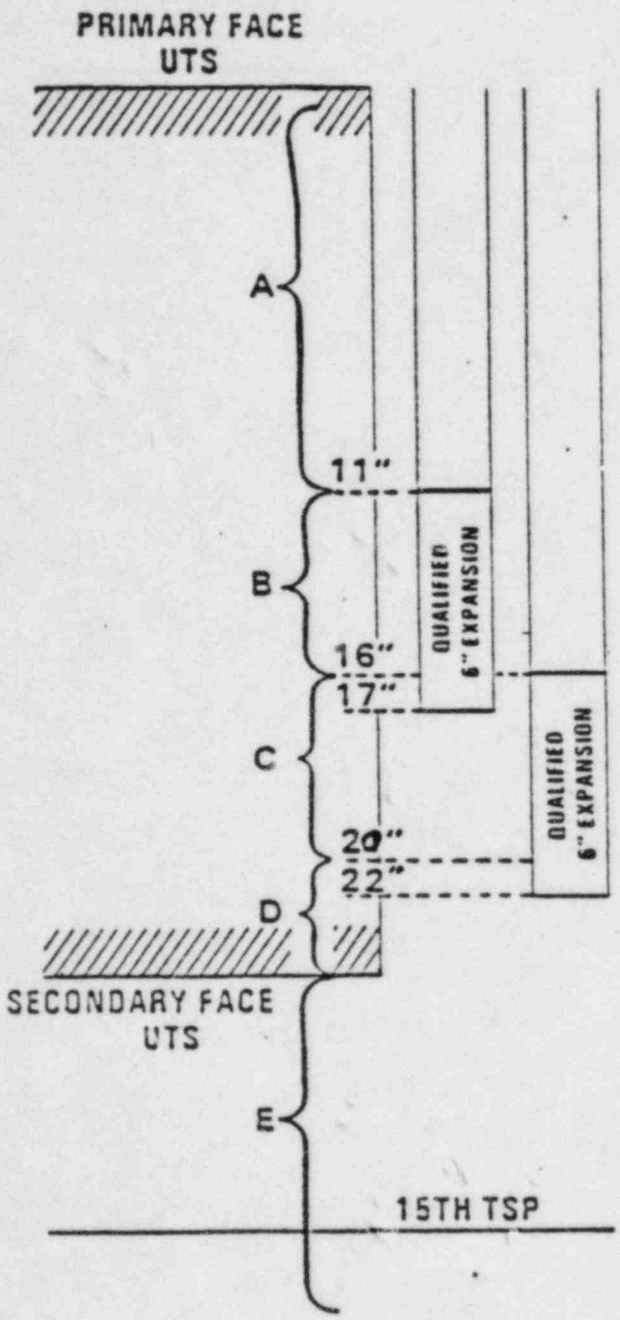
D. Safety Evaluation Logic

To determine if the plant could be safely returned to service, a program was initiated to define all the significant effects of operation of the steam generators after exposure to the damage mechanism and after the steam generators were repaired. The main product of this program was a logic diagram which defined the major areas that needed to be addressed and also defined the detailed tests, inspections and analyses which were performed to support each of these areas. A condensed version of this logic diagram is presented in Figure I-7. This diagram lists the major areas that were considered and references the sections of this report which describe the results which support the conclusion that the TMI-1 Steam Generators can be operated safely. The results of these programs demonstrate the following:

(1) The failure mechanism is understood well enough to define the root cause of the steam generator damage;

FIGURE I-6

Kinetic Expansion Length



Expanded only

ZONE WITH DEFECTS	LENGTH OF EXPANSION
A	17
B	22

Expanded and Removed from Service

ZONE WITH DEFECTS	LENGTH OF EXPANSION
C	22
D	17
E	17

PLANT RETURN TO SERVICE SAFETY EVALUATION OVERVIEW

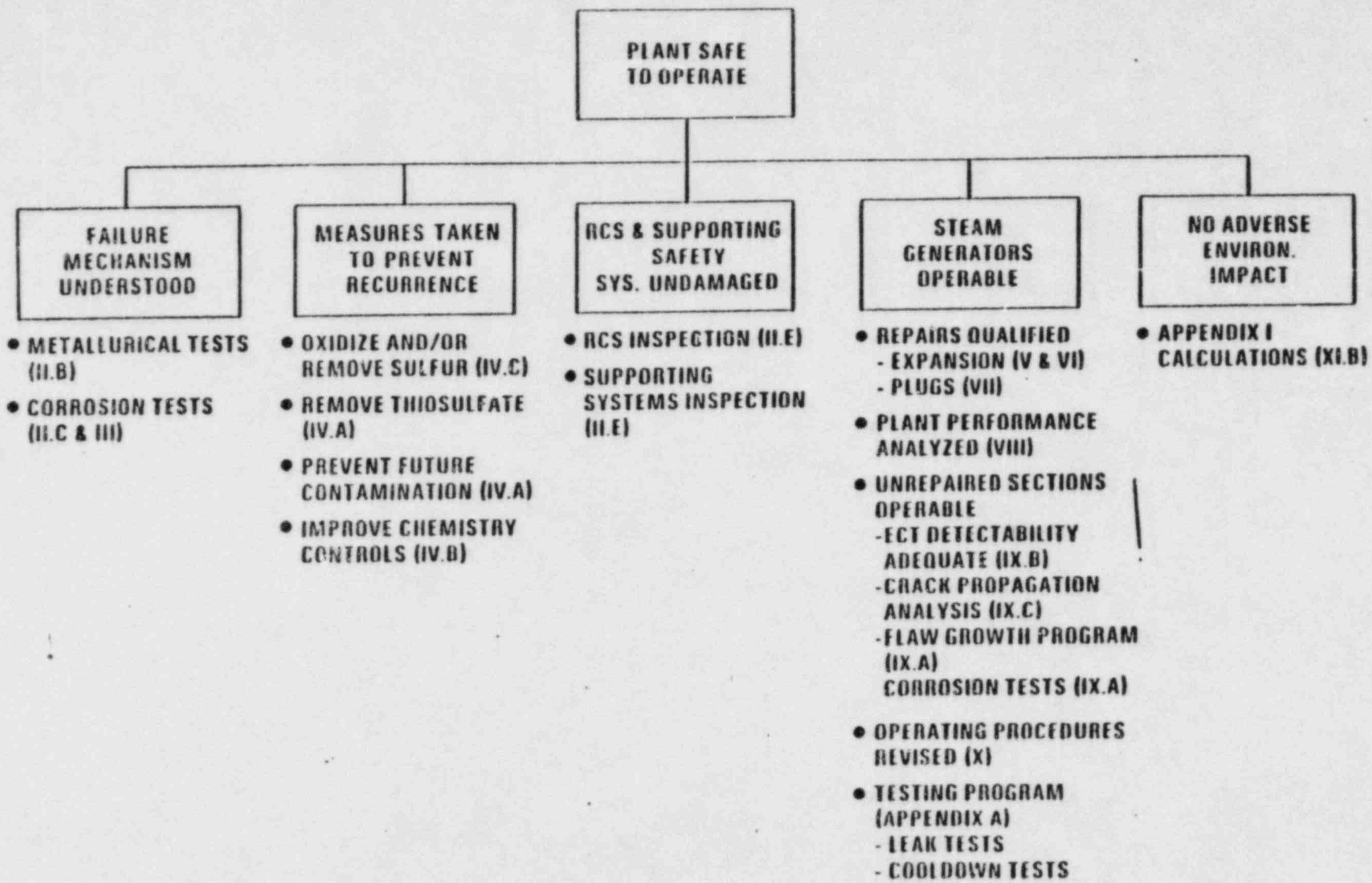


FIGURE I-7

(2) Other components in the RCS and supporting safety systems were not visibly damaged by the failure mechanism;

(3) The plant can be operated such that this failure mechanism is arrested and will not recur;

(4) The Steam Generators can be repaired and operated within the design basis;

(5) The plant can be operated with some tube leakage without adversely impacting the environment.

The remainder of this section provides a brief synopsis of the entire report with emphasis on the logic used to determine that the plant can be safely operated with repaired steam generators.

Report Summary

A detailed failure analysis was performed including (1) review of the OTSGs fabrication history, (2) coordination of metallurgical examinations of tubes pulled from the OTSGs, (3) review of the OTSG operating plant chemistry histories, (4) coordination of OTSG tube stress analyses, and (5) development of a failure scenario. This failure scenario, which provides a reasonable match between plant conditions and the mechanism which caused the tube cracks, concludes that sulfur contamination in the presence of sensitized tubing material at the oxygenated, cold conditions existing after hot functional tests led to the observed intergranular stress assisted corrosion. Section II summarizes the failure analysis.

An inspection of additional RCS components which included nondestructive testing was performed to determine if other components sustained similar damage to that found in the OTSG. Emphasis was placed on materials which were susceptible to attack in components which fulfilled critical functions. No damage was found. An inspection of RCS supporting systems has also been conducted. Details can be found in Section II.E.

As shown in Section IV, paths for chemical injection into the RCS and administrative controls on chemicals were examined in an effort to prevent future chemical contamination of the RCS. Additional periodic chemical analyses will be performed during plant operation and some administrative limits for chemical concentrations have been changed. A sulfur conversion and removal process to clean the surfaces of the Reactor Coolant System has also been conducted.

To determine that the OTSG is operable in accordance with the original design basis, the OTSG was analyzed in two sections: the repaired portion and the unrepaired portion. In the repaired region, both the expansion repair and tube plugging were considered. For the expansion repair the important characteristics were the load carrying capability and leak tightness of the new joint. A 6 in. expansion was qualified as the design basis load carrying joint using mechanical and corrosion tests. Details of this program are summarized in Section V. In addition to the qualification program, a process monitoring program was set up to oversee the expansion process.

Plugging repair is summarized in Section VII. B&W Welded Plugs, B&W explosive plugs and Westinghouse rolled plugs were qualified. Analysis verified that adjacent expansions would have no detrimental effect on existing plugs, and analyses documented in Section VIII show that the system will not be adversely affected by either the number or distribution of plugged tubes for normal, accident and transient performance.

In the unrepaired region of the OTSG, various tests and analyses discussed in Section IX have shown that:

(1) Corrosion tests indicate that the cracking mechanism has been arrested and does not reactivate in low sulfur water chemistry. If rapid cracking should reactivate due to an unknown mechanism at operating temperatures or during heatup and cooldown cycles, it is anticipated that the precritical testing sequence would allow sufficient time for defects to propagate through wall to a size that would allow leakage to be detected. Therefore the precritical leakage monitoring during the hot testing will detect crack propagation.

(2) Analysis has demonstrated that cracks below a minimum range of length and through wall thickness will not propagate mechanically. Analyses included calculating a minimum size below which a crack will not become unstable due to plastic tearing or ligament necking during a main steam line break (MSLB). This range of crack sizes is detectable by the ECT inspection system that was used to inspect the steam generators.

(3) Any defects in the detectable range that are undetected during the 100% ECT inspection because of equipment or analyst error will be exercised during the test program. If they are 100% through wall and of a size to propagate to failure under loading, they will be detected by leakage monitoring programs.

Both an ECT flaw growth program which monitored a sample of tubes for new defect indications and corrosion testing on actual defective TMI tubes in the present primary coolant chemistry, showed that the damage mechanism had been arrested.

To determine if all unacceptable defects were detected by ECT and those defects not detected would not propagate to failure, an extensive ECT calibration program was devised and the smallest size defect which could be consistently detected by ECT was determined. Comparison of field ECT results to metallurgical examination of tube samples removed from below roll transition in the TMI Steam Generators showed a one to one correlation between actual and ECT predicted defects. Stress analysis showed that cracks of the size that could propagate to failure by combinations of mechanical loads were within the ECT detectability limits. Local IGA one to two grains deep was examined during the metallurgical examination program and there was no indication that this effect was related to the failure mechanism.

A precritical testing program has been designed that will provide confirmation of the adequacy of the OTSG repair and OTSG operability. The program tests for leakage in the repaired region using secondary to primary drip and nitrogen bubble tests, and a primary to secondary operational leak test. In the unrepaired region, axial stresses will be placed on the OTSG tubes from normal and accelerated cooldown transients. The accelerated cooldown will be at a rate larger than the normal cooldown rate based on past operating experience but will be within the cooldown rate limitations of the existing Technical Specifications. A period of hot operation is included which will allow time for defects on the threshold of propagation to propagate or leak. Leakage calculations indicate that leakage from tubes with mechanically unacceptable through wall cracks will be detectable during the test period.

Operation with a primary to secondary leak at the repair design goal of 1 lb/hr. and at a more conservative rate of 6 gal/hr. has been evaluated. These leakage rates have been found to pose no threat to the health and safety of the public and allow the plant to operate within existing Appendix I Technical Specifications. Details can be found in Section XI.

This report concludes that TMI Unit 1 can operate with the repaired OTSGs without undue risk to the health and safety of the public.

II. FAILURE ANALYSIS

Three Mile Island Unit 1 was in cold shutdown from March 1979 until September 1981. In September 1981 hot functional testing was performed. The plant was returned to cold shutdown for some final modifications prior to startup. The plant was pressurized to about 40 psig in November 1981 and small leaks from primary to secondary side were detected in the tubes of the once through steam generators (OTSG's).

A detailed failure analysis was performed to determine the root cause of the steam generator damage. This analysis included a review of the steam generator operational history, a metallurgical and corrosion test program, a review of OTSG stresses and fabrication history, and the development of a failure scenario. In addition, the degree of damage both in the OTSG's and the remainder of the RCS was investigated.

A. Operational History

The time of the OTSG tube failures may be bracketed based on operational considerations. During HFT on September 4, 1981 the leak rate of the RCS at full pressure was measured and found to be within specification at .5 gpm. On November 21, 1981 with the RCS at about 40 psi, leakage through the OTSG tubes was observed.

A review of operational history of the TMI-1 steam generators was performed for the period April, 1979, through November, 1981 to determine whether instances of chemical contamination or excessive tube stress could be identified as the cause of the tube failures. A detailed description of OTSG operating history is found in Reference 2 and Reference 22.

The operational history of the TMI-1 OTSG's reveals that the tubes were not subjected to excessive stress, and generally, the reactor coolant system chemistry remained within specifications for the period extending from April 1979 through November 1981. Certain operational events did, however, have a significant impact on the chemical environment of the OTSG tubes. There were five identifiable instances of probable intrusion of chemical contaminants into the Reactor Coolant System (RCS). In March 1979 oil was introduced into the Reactor Coolant Bleed tanks probably by overflowing the miscellaneous Waste Storage Tank through the vent header. Some oil may subsequently have found its way into the RCS. Tube surface analysis has shown that carbon was present on the surface in the form of carbonate and hydrocarbons.

In October 1979 sulfuric acid was injected into the Reactor Coolant Makeup System. Although attempts were made to prevent the acid from reaching the RCS, chemistry results indicate some contami- nation of the RCS occurred (see Reference 22). In July 1980, May 1981 and September 1981, a surveillance test was performed which may have allowed sodium thiosulfate from the Reactor Building Spray System to find its way into the RCS. Sodium thiosulfate at levels of 4-5 ppm as thiosulfate is considered to be the most likely contaminant. The ionic species from the first contamination incident in July 1980 were removed from the bulk liquid by demineralization in August 1980. The ionic species from the second contamination incident in May 1981 appear to have been only partly removed by processing through a resin water precoat filter in August 1981. A 1-2 ppm thiosulfate residual could have still been present at the start of September 1981. Additional sodium thiosulfate in the RCS may have resulted from injections of Borated Water Storage Tank (BWST) contents during cooldown from hot functional testing. This water had been previously mixed with water from the Reactor Building Spray piping. The quantity of thiosulfate was not sufficient to be detectable by conductivity.

Significant to the localization of the attack was the history of the water level on the primary side of the OTSG. Following the hot functional testing in September 1981, water level was promptly lowered on September 8, 1981 then slowly raised over the rest of the month. This allowed a drying then rewetting of the tubes in the upper portion of the steam generator, causing chemical concentration in that region.

Oxygen introduction is also believed to have played a role in the damage mechanism. There were three occasions when oxygen was introduced into the system. The water from the BWST injected during high pressure injection and lowe pressure testing was probably saturated with oxygen to approximately 8 ppm. When the water level was lowered, the OTSG primary side was vented to the waste gas system. The maximum oxygen specification in that system is 2%. Thus, oxygen was available at the liquid surface while the liquid level was being lowered. The RCS was vented to atmosphere through a CRDM vent on October 7, 1981 and remained open until filling in November when the leaks were discovered.

B. Metallurgical Test Program

After identification of the leaking OTSG tubes by nitrogen bubble testing, it was decided that in order to determine the cause of failure, tube samples would need to be removed from the steam generators for analysis. The initial selection of tube samples was made after eddy-current testing had been commenced and the choices were made based on maximizing the number of defect indications in each tube and providing an adequate sample of eddy-current signals for eddy-current qualification.

Four tubes were initially selected from the "B" generator. One tube was a known leaker from the bubble test results, the other three tubes contained eddy-current indications of greater than 80% through wall penetration.

After the initial samples had been removed, it was confirmed that eddy-current signal anomalies were showing up at the roll transition region. In order to determine the disposition of these tubes, additional tube samples were selected for removal which contained these eddy-current signals. This time, fifteen (15) tubes were removed from the "A" generator.

A third set of tube samples were removed which included 6 tubes from the "B" generator and 4 tubes from the "A" generator. These samples were taken to obtain some low level defects from deep in the steam generator, to sample tubes from specific areas, and obtain tube ends to be characterized (in previous samples the tube ends had been removed during pulling).

1. Analysis Program

A multi-task program was conducted to provide information related to the steam generator tube damage problem. This program contained the following analyses/examinations:

a. Visual Examination
b. Eddy-Current Examination
c. Radiography
d. Sectioning and Bending
e. Scanning Electron Microscopy (SEM) and Energy Dispersive X-Ray Analysis (EDAX)
f. Auger Electron Spectroscopy (AES)
g. Electron Spectroscopy for Chemical Analysis (ESCA)
h. Sodium Azide Spot Test
i. Metallography-Microstructural Analysis
j. Scanning Transmission Electron Microscopy (STEM), Electrokinetic Potentiostatic Reactivation (EPR) and Huey Testing
k. Residual Stress and Plastic Strain
l. Tension Testing.
m. Hardness Testing.
n. Dimensional Measurements.

2. Test Program Results/Conclusions

The detailed test results are presented in Reference 2. The following summarizes those results and sets forth some conclusions.

a. The tubing has failed due to intergranular stress assisted cracking. The intergranular morphology has been

confirmed by Metallography and Electron Microscopy. This has led in many cases to through wall penetrations and circumferentially oriented cracks. In all cases, cracks have initiated on the primary side surface.

b. Microstructural evaluation of the tubing from numerous locations, has indicated that the structure is representative of that normally expected for steam generator tubing. Tests have concluded that the material is in a sensitized condition and hence is expected to be susceptible to intergranular attack in oxidizing acids.

c. Transmission Electron Microscopy has also confirmed that no secondary mode of failure is associated with the intergranular corrosion, that is, no evidence of any low or high cycle fatigue was observed on these fracture surfaces.

d. The consistent circumferential orientation of the cracks below the weld heat affected zone, indicates that an axial stress is part of the cracking mechanism. Residual stresses in the roll alone were not responsible for the cracking. Therefore, the fact that the cracks occurred when the tube was under a higher applied axial tension stress rather than hoop stress, confirms that the cracks formed during cooldown or cold shutdown.

e. Axial cracks have been observed at the top end of the tubes near the seal weld. Some of these cracks penetrate 100% through the wall but they do not penetrate the weld metal. The axial orientation in this case is expected based on the residual stress distribution in the area of the seal weld.

f. Auger analysis of surface films on fracture surfaces and on the I.D. surface of the tubing indicates that sulfur is present up to levels of eight atomic percent. The sulfur concentrations along the I.D. surface of the tubing down to the 9th tube support plate, are generally uniform with perhaps a slightly decreasing level lower in the tube sample. The form of sulfur is believed to be either in the form of nickel sulfide (Ni_2S_3), or some other reduced form of sulfur. The reduced sulfur form generated from the contaminating species is directly responsible for the cracking mechanism.

Auger analysis also showed that carbon was present at levels from 50-90 atomic percent on firs and second

round tubes, but a maximum of 50% on third round tubes. It is thus inferred that the extensive carbon contamination on the first and second round tubes was the result of contamination either during or immediately after tube removal.

In addition to sulfur and carbon, the Auger and ESCA analysis have shown the presence of nickel, chromium, oxygen and normal trace quantities of fission products on the fracture surface.

g. In conjunction with the cracking, there has also been intergranular corrosion observed. These "islands" of IGA are not always associated with cracking and in general are associated with I.D. deposits. IGA found at crack locations tend to penetrate deeper than the approximately 1.5 to 3 mils of penetration typical of the IGA "islands." Most severe cracking in general relates to more severe intergranular corrosion.

h. In 39 out of 42 cases to date, cracks which have been examined either by metallography or by bend testing have shown the defects to be 100% through wall. The remaining three cases exhibited penetrations of 66, 70 and 70%.

C. Corrosion Test Program

A corrosion test program was put into place and addressed the areas of crack arrest, corrosive species and verification of the corrosion scenario. The corrosion testing program is addressed in detail in Section III of this report.

The following conclusions can be drawn from corrosion tests which relate to the failure scenario.

a. Thiosulfate can produce cracking similar to that observed in the steam generator tubing.

b. In the absence of thiosulfate no cracking has been produced in the laboratory in primary water chemistry.

c. Tubing removed from the steam generators appears to have a lower thiosulfate concentration threshold for cracking than an equivalent archive tube which has been sensitized.

d. Tubing thermal history is a key parameter in establishing material susceptibility. A threshold level of sensitization must exist. Data suggests higher mill annealing temperatures favor cracking in sulfur contaminated primary water.

e. Crack initiation and growth rate are temperature dependent. For susceptible material, crack initiating time will be decreased and crack growth increased by raising temperature up to 170°F.

f. An oxidizing potential is required for cracking to occur. In the absence of oxygen, cracking has not been observed in the laboratory.

g. Crack growth rates appear to be very rapid and can be as high as 1 mm/day. Lab specimens have exhibited partial through wall penetration in areas of lower stress.

D. Damage Scenario

The conditions needed for Intergranular Stress Assisted Cracking were evaluated and compared to the conditions in the TMI OTSG's. Based on stress analysis, fabrication history, the timing of the cracking, metallurgical and corrosion testing and observed features of the cracking phenomena, a failure scenario was proposed.

1. Intergranular Stress Assisted Cracking (IGSAC)

The occurrence of stress assisted cracking requires that three conditions be satisfied simultaneously:

- a sufficiently high tensile stress
- a susceptible material microstructure
- an aggressive environment

The information presented in Reference 2 relating to those three factors is summarized below.

a. Tensile Stress

Since the cracks are oriented circumferentially in the tubes below the weld heat affected zone, the sum of the operating and residual stresses in the axial direction was greater than that in the hoop direction. Axial tensile stresses are of principal interest. Very little tensile stress is required to crack Inconel that is this susceptible in the presence of reduced forms of sulfur. However, the higher the tensile stress the more rapid the crack propagation and the more cracks that actually occur.

The stress analysis results suggests that the cracking must have occurred during cooldown or during cold shutdown because the axial tensile stresses are largest during this time. The analysis also indicates that the seal weld heat affected zone and the roll transition regions would be particularly prone to cracking due to locally high axial tensile stresses which are possible in that region. More cracking occurred in the periphery than in the center of the tube bundle because the axial stresses at and below the roll are generally larger at the periphery than in the center of the tube bundle.

b. Susceptible Material Microstructure

There is no indication that tube material, fabrication or installation in the OTSG's was in any way extraordinary. The heat treatment of the whole OTSG following assembly puts the tubing into service in the mill annealed plus stress relieved condition which is expected to be heavily sensitized (i.e., low grain boundary chromium content less than 10%) thus making it more vulnerable to IGSAC . Metallurgical examination has confirmed that the expected microstructure is present.

A large number of heats of Inconel 600 are present in the OTSG's which differ in composition and which may have responded differently to the stress relieving heat treatment. The degree of susceptibility as a function of the tubing heat number could not be established.

c. Aggressive Environment

As previously stated in Section II.A, the results indicate that sulfur was present in the primary system water and three possible sources of sulfur have been identified from the OTSG chemistry history.

If SO_4 and S_2O_3 were introduced to the primary water as the OTSG operating and chemistry histories suggest, they would be expected to persist as long as the water was at room temperature even if the oxygen content of the water was reduced by hydrazine additions. However, hydrogenating and heating the water to perform a hot functional test would be expected to result in the generation of S^{--}, possibly accompanied by S and other intermediate species. Subsequent cooling to room temperature and oxygenating following the hot functional

tests rapidly oxidize S^{--} to S and could also result in the appearance of significant concentrations of other species of higher oxidation states. Although it is not possible to predict either the identities or the concentrations of the sulfur species present following the hot functional test, it is clear that this transient is likely to have greatly affected the aggressiveness of the environment with regard to low temperature sulfur induced attack of the OTSG tubing.

2. Proposed Failure Scenario

This following scenario is consistent with all the observed features of the cracking phenomenon, the timing of the cracking and the results of the metallurgical examinations and corrosion tests.

a. During layup the primary system was contaminated with sulfur by the accidental introduction of sulfuric acid, sodium thiosulfate, and possibly a sulfur-containing oil. The amount of sulfur present may have reached several ppm, but the contaminated water was not aggressive enough to crack mill annealed plus stress relieved Alloy 600. The corrosion tests confirm that cracking would not have been expected to occur at this stage.

b. The temperature and oxidation potential transient associated with the hot functional test resulted in a change in the types and concentrations of sulfur species present in the primary water. Further changes occurred when thiosulfate-contaminated oxygenated water was injected during the tests of the HPI and LPI systems.

c. When the water level in the OTSG's was lowered following the hot functional test, high concentrations of aggressive metastable sulfur species developed in the dry-out region at the top of the generators due to the combined effects of solution concentration by evaporation and the comparatively high availability of oxygen. Changes in the sulfur species in the more dilute bulk solution proceeded more slowly resulting in lower concentrations of aggressive sulfur species.

d. Sulfur-induced IGSAC of the Alloy 600 tubing occurred rapidly in the dry-out zone with preferential attack at high stress locations in the most highly sensitized tubes. Cracking occurred to a lesser extent lower in the generator. Statistically this would be expected

because the bulk solution was less aggressive than the environment seen by tubes in the dry out zone. Cracks would occur in areas low in the generator which were slightly more susceptible to IGSAC due to surface film anomalies or residual stress anomalies.

e. Cracking terminated either because continued chemistry changes resulted in the formation of less aggressive sulfur species or because the environment in the dry-out region was diluted by the slowly-rising bulk solution. By the time the water level was dropped again, the chemical state of the sulfur in the primary water was sufficiently different from its state immediately after the hot functional tests to prevent a recurrence of steps C and D in the new dry-out zone.

f. Cracking was discovered when the OTSG's were pressurized.

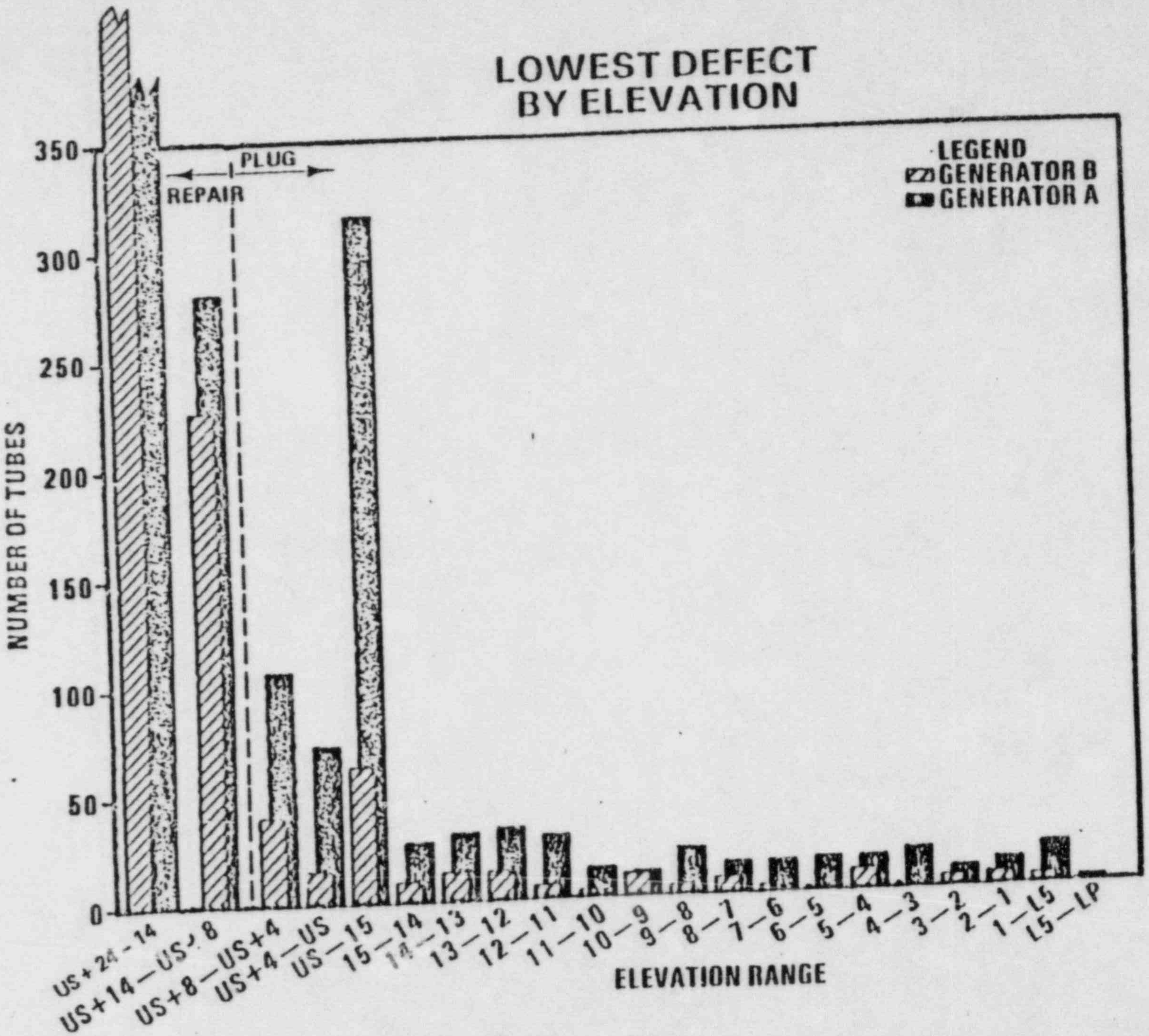
E. Distribution of Damage

To evaluate the extent of the damage, an eddy current testing (ECT) program was devised to examine the OTSG's. In addition, an inspection of other components in the reactor coolant system (RCS) and supporting systems was conducted to determine if damage similar to that found in the OTSG's was evident.

1. OTSG Eddy-Current Examinations

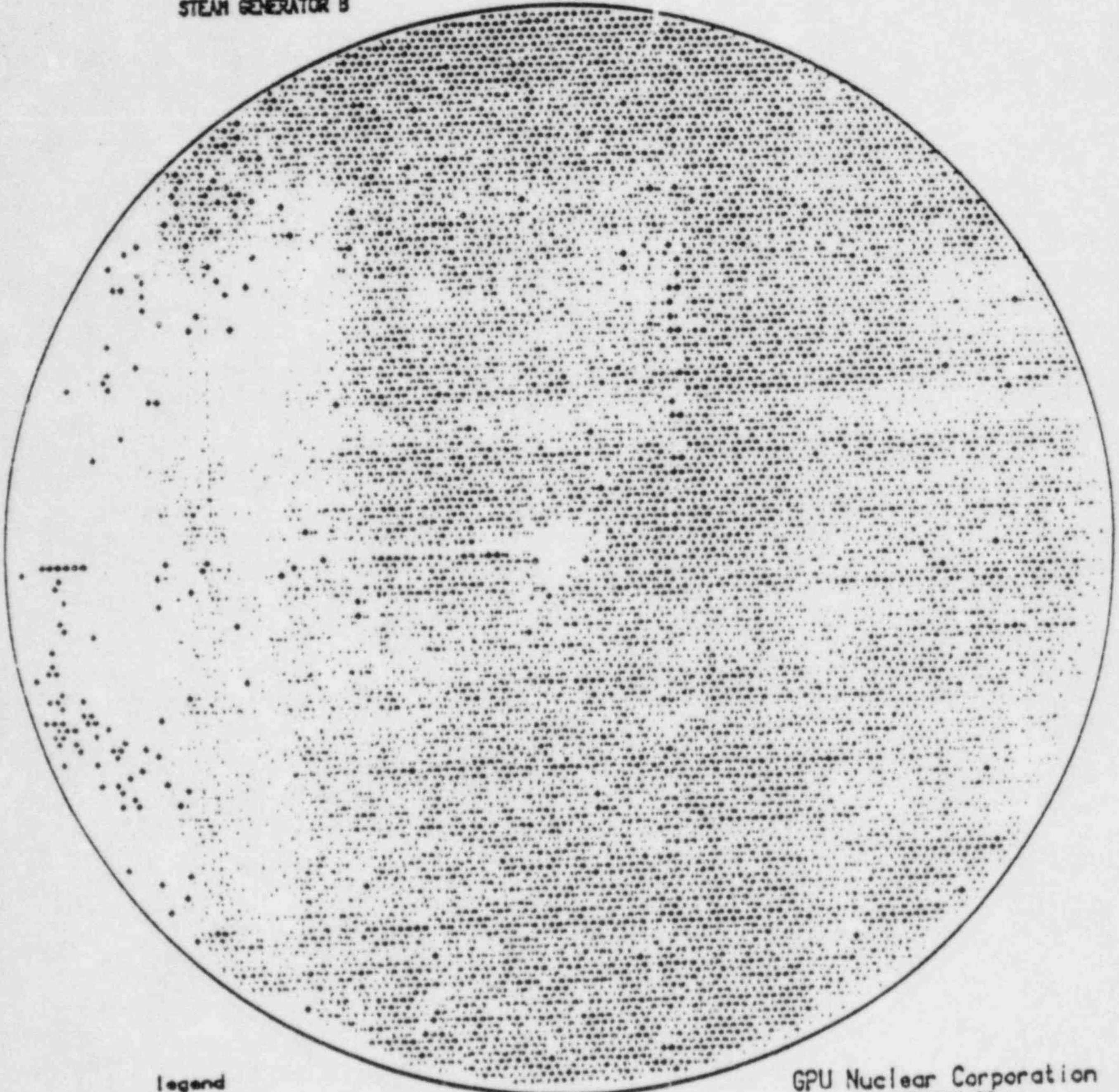
Special eddy current techniques were developed and an extensive testing program was established to provide an accurate description of actual OTSG tube cracking (Reference 20). In-situ eddy-current results exhibit tube wall defect indications at varied densities distributed both axially and radially in both OTSG 'A' and 'B' tube bundles. The majority of the defect indications were in the upper tubesheet (UTS) region and particularly confined in the tube roll transition zone. After an absolute probe inspection of the roll transition and mechanically expanded area of approximately 18,000 tubes, ECT indications were being reported with such frequency that it was decided to affect a kinetic expansion for all tubes in both tube bundles. Further ECT data was not interpreted above elevation US+14 inches due to the decision to repair the top 17 inches of all the tubes. Figure II-1 gives the number of tubes with defects by elevation in each generator. Radial distribution of tubes (as shown in Figure II-2 and II-3) with defect indications requiring plugging in both 'A' and 'B' OTSG shows a h'-her percentage in the periphery with the defect

FIGURE II-1


LOWEST DEFECT
BY ELEVATION
LEGEND
GENERATOR B
GENERATOR A
REPAIR
PLUG
NUMBER OF TUBES
0
50
100
150
200
250
300
350
ELEVATION RANGE
US+24-14
US+14—US+8
US+8—US+4
US+4—US
US—15
15—14
14—13
13—12
12—11
11—10
10—9
9—8
8—7
7—6
6—5
5—4
4—3
3—2
2—1
1—L5
L5—LP

THREE MILE ISLAND NUCLEAR
GENERATING STATION

UNIT 1
STEAM GENERATOR B



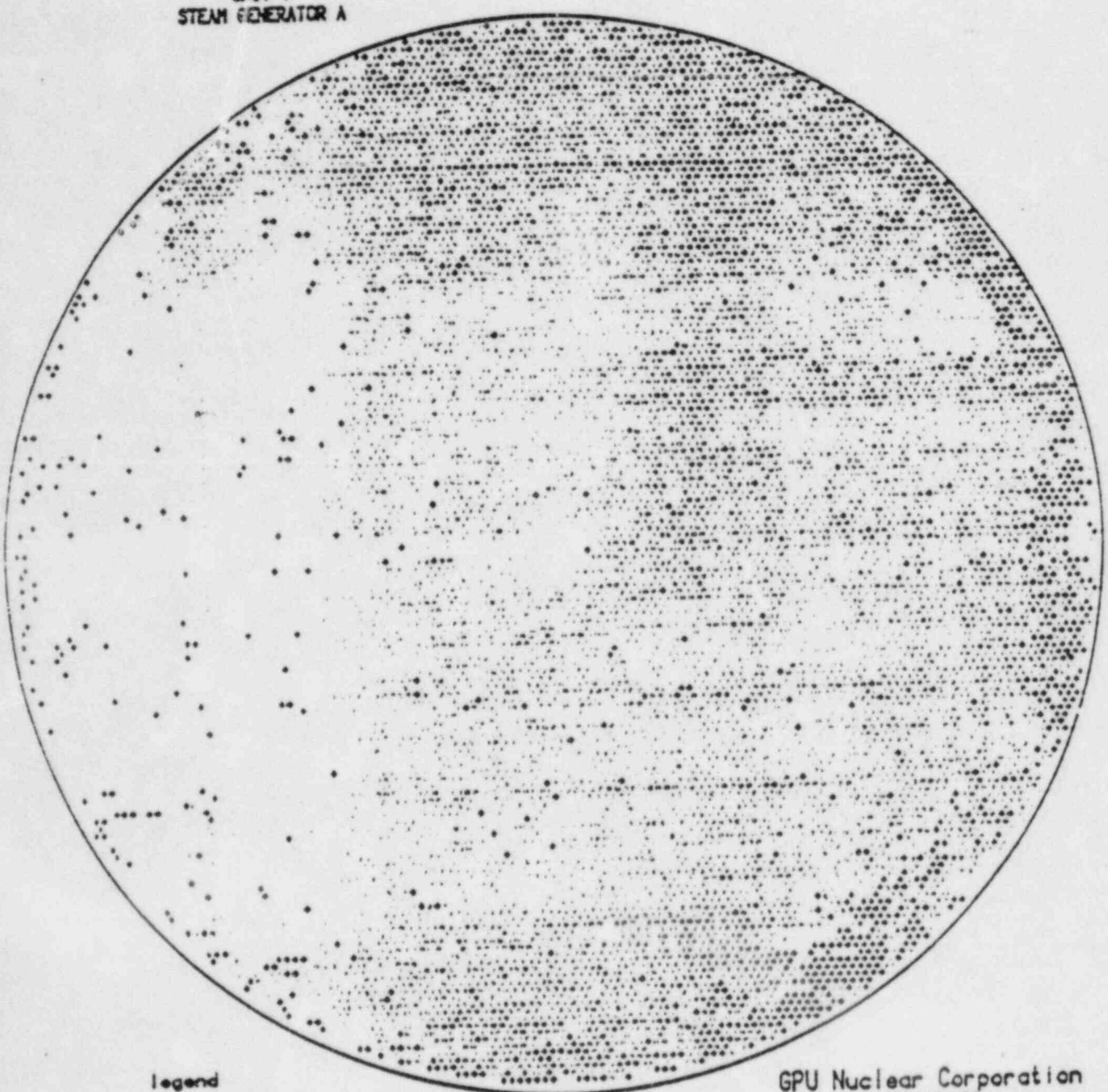
legend

• PLUGGED TUBE

GPU Nuclear Corporation
18-NOV-82

THREE MILE ISLAND NUCLEAR
GENERATING STATION

UNIT I
STEAM GENERATOR A



legend

+ PLUGGED TUBE

GPU Nuclear Corporation
18-NOV-82

rate decreasing as you move toward the center of the bundle. Defects indicated below the upper tubesheet are located toward the periphery in the 16th span and were random below the 16th span. References 20 and 63 give a detailed description of ECT results.

2. Tube End Damage

In the fall of 1982, corrosion and cracking problems were identified in the steam generator tube ends, where they extend above the seal weld and upper tube sheet. The tube end damage was evident with metallurgical analysis of tube ends removed from the generators with the last 10-tube sample. After kinetic expansion, damage was visible. The typical crack above the seal weld is a combination of both axial and circumferential cracking, the pattern depending on stress due to weld shrinkage in the heat affected zone of the seal weld, and on other factors. Metallurgical evidence shows that the weld material arrested the cracks in all samples, although some cracks extend through the tubing material behind the weld to the tubing below. The force of kinetic expansion removed parts of some tube tops where a circumferential crack was located in conjunction with vertical cracks. Other tube tops were bulged out, where vertical cracks were through wall but circumferential cracks were in regions with ductile material remaining.

In order to further define the problem, GPUNC removed tube end pieces from the tops of approximately 12 tubes and conducted a metallurgical examination in order to define what, if any, ductility remained. The evidence from this examination indicated that about 1/3 of those pieces removed were intergranularly cracked on all sides (both circumferentially and axially).

Evaluation of the metallurgical evidence indicated that the weld material arrested the cracks in all cases noted. (Ref. 57). Additional dye penetrant tests were conducted on seal welds in the upper tubesheet to further confirm that the welds and the heat affected zone between the tube seal weld and the tubesheet cladding were not cracked. The absence of cracking as noted in these dye penetrant checks provides assurance that the seal welds themselves and the upper tubesheet cladding were not cracked. Similar examinations of the lower tubesheet welds and tube ends also showed no damage.

With the damaged areas defined, GPUNC evaluated the potential for loose pieces from the tube ends both above the seal weld and in the area behind the weld where vertical and circumferential cracks existed. This evaluation is documented separately in Reference 55. It was concluded that tubing below or behind the seal weld was unlikely to be degraded to the point of loosening under the low loading in these areas. However, tubing above the seal weld was considered to have potential to break loose. Thus, the decision was made to remove all tube ends above the seal weld by milling.

3. RCS Inspection

The sulfur induced attack on the OTSG tube prompted an inspection of other elements of the Reactor Coolant System, to determine if other components sustained similar damage. An inspection plan was developed based on a review of the materials involved and the accessibility of the materials within the system. Representative items in the Reactor Coolant System that were most likely to have suffered attack were selected for examination. The items chosen represented the most susceptible materials and reflected environmental and stress concerns.

Materials located in either of three environmental conditions were evaluated.

a. Primary coolant-air interface where most of the defects occurred in the OTSG.

b. Dry areas since the last refueling, but which have been previously wet.

c. Wet areas, covered by primary coolant.

Since the known attack had occurred in the OTSG on stress-relieved Inconel 600 tubing material (PWHT) which was under stress in the cold shutdown condition, this same and other similar conditions were, therefore, to be suspected in other parts of the RCS. In addition, attention was given to other materials which are known to be susceptible to IGSAC. Other than the OTSG tube preload stress, areas of concern with respect to stress included bolting that has a steady load due to torqueing, residual stresses induced by welding, and force-fit items.

The plan included tests of sufficient diversity to reflect the different materials, stresses, and environments that are present in the RCS. The premise for this logic is that generic material groups will behave similarly. Therefore, heat-to-heat variations were not considered unless evidence of intergranular attack and stress assisted cracking existed.

The inspection plan was developed to also account for critical functions of the RCS items. The function of the pressure boundary, core support, and fuel integrity received the most emphasis. This was to determine the general condition of the system and, of course, because they are the most directly safety-related.

The non-destructive examination methods used were; ultrasonic, liquid penetrant, eddy current, radiography, visual, and wipe sampling. Other examinations included functional check on equipment and destructive metallurgical examinations, both at the TMI-1 site and at B&W Research Laboratory at Lynchburg. The selection of examinations was governed by factors relating to the type of material, geometry of material, location and accessibility, and radiological control limitations. The following is a summary of methods used and example materials examined by each method.

Ultrasonic Examination Method - this inspection included the pressurizer spray nozzle safe end, CRDM motor tube extensions, make up piping nozzles, plenum lifting lug bolts, plenum cover to plenum cylinder bolts, pressurizer surge nozzle, core barrel bolts and low pressure injection pipe welds.

The ultrasonic method used to examine bolts of the TMI-1 core barrel assembly had the capability of detecting indications having a depth of 20 percent of the diameter of the bolts. This sensitivity is considered sufficient primarily because a large number of bolts were examined at TMI-1 and no evidence of intergranular attack or IGSAC was found. For example, 96 of the core barrel assembly Inconel X750 bolts were UT inspected; if intergranular attack or IGSAC had occurred, it is likely to have been detected in this extensive sample.

Radiographic Examination Method - This method is a volumetric type of examination that produces a visual image of the test specimen. For this reason, this method was chosen to validate the structural integrity of the thermal sleeves for the safe end nozzles. The pressurizer spray nozzle and the three make up nozzles were located in a coolant/gas interface and the coolant dry area respectively.

Liquid Penetrant Examination - Special consideration was given to the welds of the secondary oversheath to assembly oversheath of the incore detectors. Items examined by this method were: Upper OTSG Inconel (tube sheet) and stainless steel weld cladding and the incore detectors closure and sheath, incore detector the dry region portion make up nozzle, lower OTSG cladding surface and incore detector portions from the wet regions.

Eddy Current Examination Method - The ID surfaces of the RV vent valve thermocouple and the CRDM nozzle were the areas of special concerns which required this method of volumetric and surface examination. Both components are located in the area basically dry of coolant.

Visual Examination Method - Concern for the fuel integrity was the major reason for incorporating these inspections. The areas of interest were submerged by the reactor coolant; the top of core control components, the baffle plate region and the annulus between CSA and RV. Areas of similar conditions, even though they were dry of reactor coolant, were the plenum assembly and the vent valve assembly.

Wipe Sampling Method - This method was performed prior to non-destructive examination other than visual. The samples were chemically analyzed to determine the concentration of any aggressive species.

The results of the inspections and tests which involved over a thousand selected components, indicated that there was no evidence of a problem similar to that seen on the OTSG tubes. The functional tests all indicated that the tested assemblies were operational. The destructive examinations revealed that even on a microscopic level, no evidence of intergranular attack could be found. Therefore we conclude that based on this Inspection & Test Plan, the materials in the Reactor Coolant System are re-certified for continued safe operation. The details of this inspection are reported in Reference 21.

4. Supporting Systems Inspection

An IGSCC problem was originally detected in the Spent Fuel System in 1979, and a three year inspection program was established which was specific to Spent Fuel, Decay Heat and Building Spray Systems. As of June 25, 1982 all required volumetric examinations of the first cycle on the IGSCC schedule were completed and no discrepancies were noted. As

of August 5, 1982, visual examinations were completed for Decay Heat and Building Spray with no additional indications identified. The plotting and trending of the known indications did not reveal evidence of growth. In March 1982, cracks which were attributed to IGSCC were found in the Waste Gas System.

In October 1982 and February 1983, examinations of PORVs which had been removed from service also showed damage attributed to sulfur intrusions. Damage to the PORV internals can be characterized as general corrosion and pitting rather than IGSCC. Valve internals affected were made of martensitic stainless steels and inconel. The corrosion apppeared to result from physical/gaseous transport of sulfur species. As a result of these findings, additional supporting systems inspections have been conducted, including inspection of the pressurizer, and a program was implemented to identify sulfur concentrations in plant fluids and on the surfaces of system components. Results are documented in Reference 64 and were reported in response to LERs 82-02, 82-11, and 83-03. Some minor corrosion and surface pitting were identified, but no additional significant damage was found. Damaged components have been repaired or replaced, and the pressurizer has been cleaned by hydrolazing.

III. CORROSION TEST PROGRAM

A. Introduction

An extensive corrosion testing program was initiated in December of 1981 to support the steam generator repair program. The program in several phases was designed to accomplish the following: (1) Determine the conditions under which the corrosion mechanism occurred and how it could be arrested, (2) Verify the proposed corrosion scenario to provide assurance that the mechanism was understood (3) Determine whether tubing that has been kinetically expanded would be more susceptible to corrosion in service than other tubing and (4) verify that cleaning using hydrogen peroxide will not cause corrosion. The following sections describe the results of this program.

B. Corrosion Mechanism Determination Tests

In December 1981, analysis of tube samples removed from the TMI-1 "B" Steam Generator identified the corrosion mechanism as stress assisted intergranular cracking. Cracking was circumferentially oriented and initiated from the primary side surface of the tubing. Analysis of the circumstances which led up to failure indicated that through wall penetration of cracks occurred sometime after the hot functional test sequence and prior to the pressurizing of the unit in November of 1981. In view of this fact, a concern existed that the corrosion mechanism might still be active.

A corrosion test program was immediately put into place to ascertain whether or not significant corrosion was still occurring. The first of these tests was initiated in February of 1982. In this test, sensitized samples of 304 stainless steel and Inconel 600 were immersed in primary coolant removed from the decay heat loop. This coolant was analyzed and found to contain 350 ppb sulfate. Specimens utilized in this test were bent strip specimens spring loaded to apply constant loads near the yield point of the material. Tests were conducted for two week periods at 100°F. Specimens were examined periodically for evidence of cracking an ultimately examined metallurgically to assess if any cracking had taken place. The result of this test indicated that the current environment in the primary circuit of the steam generators was not sufficiently aggressive to initiate cracks.

The next concern was whether or not existing incipient defects would, in fact, propagate under the environmental conditions which currently exist in the unit. To this end, an actual tube sample removed from the OTSG with a known eddy current defect determined to be a crack greater than 90% through wall was tested in primary coolant removed from the decay heat loop. This would have been a similar solution to that used in the

initial screening test. This test consisted of filling the tube specimen with the decay heat solution on the internal surfaces, then axially loading the specimen to 1100 lbs. at a test temperature of 100°F. However, prior to putting the primary coolant into the tube, the sample was also tested with load in dry air as well as air of high humidity. In neither case were any cracks observed. After all testing was completed, the specimen was examined metallurgically to look for signs of growth. There was no obvious extension of the intergranular cracks and no evidence of additional attack in the area of this crack. It thus appeared that crack growth was also arrested and no further tube degradation was expected. This was confirmed by the eddy current examination performed on the 100 tube sample throughout the next several months. No evidence of any growth of known defects or detection of new defects was observed from December 1981 to the termination of program in July 1982.

In March of 1982 after this initial testing had been completed, indicating that cracks were neither propagating nor initiating, a program was initiated which would define the environmental conditions necessary to produce the type of intergranular corrosion observed in the TMI tube samples.

A number of tests utilizing stressed bent strip specimens were begun at the B&W Alliance Research Laboratory (Reference 27). These tests utilized anodic polarization to accelerate the cracking process and help to define electrochemical potential regimes for this cracking to occur. Solutions of boric acid containing various concentrations of thiosulfate contaminant were tested. Those tests showed that thiosulfate at levels in excess of 5 ppm would cause cracking in sensitized archive tubes provided the degree of sensitization was sufficient. It was also determined that an oxidizing potential in the presence of a reduced sulfur form was required for this cracking.

Specimens made from actual TMI tube samples removed from the steam generator were tested. These samples appeared to be more sensitive to the cracking phenomena since they cracked at thiosulfate concentrations as low as 1 ppm. This is believed to be due to either a difference in degree of sensitization of material removed from the generator or due to the effects of previous exposure of these samples to the thiosulfate contaminant in the primary system.

Samples were also tested in clean borated water during this phase of the corrosion program. It was found that in all cases, even when polarized in the cracking potential range, that in the absence of thiosulfate, specimens would not crack. Cracking was observed at open circuit potential in an air saturated evironment in thiosulfate contaminated solutions. However, if the

solution was deaerated and an inert cover gas utilized, cracking was not observed in any specimens. Based on the results of approximately 60 tests it appears that thiosulfate or reduced metastable sulfur can produce and is a necessary requisite for the cracking observed. Additional results indicated that time to failure decreased as thiosulfate concentration was increased and also as temperature was increased up to 170°F.

During this same time period testing was also being conducted at Brookhaven National Laboratories for the NRC. These tests were constant extention rate tests (CERT) utilizing solution annealed and sensitized Inconel 600 test specimens. The purposes of these tests were to define the minimum thiosulfate concentration required for cracking as well as to establish the effect of temperature and Lithium Hydroxide concentration on cracking susceptibility. The results of these tests indicated the cracking in the absence of Lithium could be expected in highly sensitized material at thiosulfate levels on the order of 70 ppb. However, in the presence of Lithium it was found that cracking would not be experienced on sensitized materials provided the ratio of lithium to sulfur remained greater than or equal to 10. Although additional tests are being planned to expand on the knowledge and understanding of the influence of lithium on inhibiting cracking, this data has been utilized in preparing new administrative chemistry guidelines for TMI-1 operation. The lower limit on lithium has been raised such that at a concentration of 100 ppb sulfate the above lithium to sulfur ratio is equalled or exceeded.

Brookhaven also conducted a series of tests to establish the influence of temperature on crack growth rate. Results of their tests indicated that approximately 170°30F produced the maximum cracking velocity.

At this phase the evaluation had established that:

- o Cracks in the OTSG were not currently propagating
- o Cracking in non-reduced sulfur contaminated environment was not anticipated
- o The corrosion appeared to be a low temperature phenomenon
- o Oxidizing conditions were required for cracking
- o A highly sensitized microstructure was required
- o Lithium hydroxide could possibly be an inhibitor of crack initiation or propagation.

From a metallurgical and corrosion viewpoint it therefore appears that a repair process is feasible, that the tubing was not damaged to the point where it no longer was serviceable; rather it exhibited properties of material which are typical for any currently operating generator.

C. Corrosion Scenario Verification Tests

During the summer of 1982, testing was conducted at Oak Ridge National Laboratories in an attempt to verify the proposed scenario. As defined in the failure analysis, it was believed that corrosion occurred during the cooldown phase after hot functional testing, a period in which oxygen was introduced into the primary system as well as lowering of the water level in the OTSG's. It was felt that the lowering of the water level allowed reduced sulfur species to concentrate in the region above the water line and in the presence of oxygen caused cracking.

Although it would not be possible to totally duplicate the corrosion scenario, an attempt was made to establish test parameters which were a close approximation to a hot functional test sequence. (Ref. 24) This included chemistries similar to that which existed at the time of the hot functional test as well as temperature cycles, plus exposure of test specimens in vapor as well as liquid phase. In addition, in order to account for any influence of tube surface films on the cracking mechanism, all test specimens were actual tube samples removed from the TMI steam generators. This allowed an assessment of whether oxidizing/reducing conditions in the steam generators could change surface films and form metastable sulfur compounds which could lead to intergranular corrosion. Autoclaves were set up to test sulfur contaminated borated water solutions with 1 ppm and 5 ppm thiosulfate and 30 ppm sulfate. This latter test assessed if oxidized forms of sulfur of themselves would be aggressive. The test sequence allowed for examination of specimens after an initial exposure at 170°F. In all cases, no cracking was observed at that phase.

The specimens were then put back into the autoclave and the temperature was raised to 500°F. Subsequently during the cool down to ambient phase, air was introduced into the system when the temperature reached 212°F. The specimens were then taken down to 130°F at which time they were held for several days. Examinations of specimens removed after the hot functional sequence showed no cracking for the 1 ppm thiosulfate solution and no cracking for the 30 ppm sodium sulfate solution. However, cracking was observed on specimens in the liquid phase of the 5 ppm thiosulfate test. No cracking was observed in the vapor phase of any test. This indicated that a threshold concentration of thiosulfate may be required for cracking to occur. What is not known, however, is whether the cracking occurred during heat up or cool down for this particular sequence. It may logically be assumed that cracking occurred during the heatup phase as tests conducted have thus far shown cracking does not occur at elevated temperatures. In addition, testing conducted in the 1 ppm thiosulfate and the 30 ppm

sodium sulfate indicates that a threshold level of available reduced sulfur is necessary and that sulfur in the surface film of itself is not sufficient to produce intergranular cracking.

D. Repaired Tubing Corrosion Tests (Proprietary)

This corrosion data base, supported the conclusion that an effective repair could be made. The choice of explosive expansion appeared to be the most technically feasible solution, however, with the expansion process came a new geometry which would have a transition from the expanded portion to the unexpanded portion of the tube which was not stress relieved. An accelerated short term test was conducted to assess the impact of this transition on the tube susceptibility to corrosion (Reference 29).

Two tests were conducted to study this particular question. One test was a 10% sodium hydroxide electrochemical test which was known to produce cracking in highly stressed roll transition regions and the second was an accelerated test in thiosulfate contaminated boric acid. Specimens consisted of Inconel single tube/tubesheet mockups with an actual expanded joint. The caustic test had previously been correlated with long term testing results, with approximately 8 1/2 years of service time corresponding to approximately 5 days of testing under accelerated exposure conditions. Test results showed no evidence of cracking.

The second test was conducted using a boric acid solution containing 1 ppm of thiosulfate and 1 ppm chloride. This level of thiosulfate was utilized because it was shown to produce cracking in highly stressed specimens of actual TMI tube samples. It was therefore felt that if the residual stresses were sufficiently high, that cracking could be expected in this environment. The chlorides were added to provide an additional accelerating effect. Tests were conducted at 170°F. If no cracking was observed in a specimen tested at 170°F, the sample was retested at 550°F. Testing was conducted on ten single tube/tubesheet mockups that had been expanded using 19 gr/ft and 14 gr/ft double expansion plus various com binations of Immunol treatment and H_2O_2 cleaning. A complete description of test specimen configuration is given in Reference 29. These tests have shown no evidence of stress corrosion in the expanded region or in other regions either at 170°F or at 550°F.

Even though all short term tests were done under accelerated conditions, it was still felt that a certain time dependency may be required for corrosion to initiate. Long term tests were

developed to address this time dependent parameter (Reference 8). These tests have been scheduled to lead the actual performance of the generator and thus provide additional insight as to the expected performance of the tubes. The long term corrosion testing program was developed to assess performance of the tubing both in the unexpanded regions of the generator and tubing at the new expanded transition region. The test is designed to run for approximately 13 months of operating time and to lead actual operation of the generator by a minimum of one month. As presently scheduled, lead testing will probably preceed operation of the generator by a minimum of 4 months.

These tests will be conducted under simulated operational parameters which will include load cycling as well as thermal cycling. Chemistry will simulate that expected under normal reactor operations. This will include decreasing boron levels as well as decreasing lithium levels throughout the test period. Test samples will be made from actual TMI steam generator tubes. Samples will be utilized both with known eddy current defects as well as without known eddy current defects. A minimum of 4 different heats of material will be utilized with samples from various elevations within the generator.

In the lead test, samples will be 6 inch full section tubes as well as I.D. stressed C-rings. This test is intended to evaluate conditions in the span below the UTS. The repair test will utilize single tube/tubesheet mockups with an expanded region in the middle of the tubesheet area. This test is intended to evaluate conditions on the new joint and the transition. Load cycling will subject samples to axial loads of 500 to 1100 lbs. The 1100 lb. load will be in conjunction with all cool downs from 600°F to ambient. Tests will also include phases where oxygen will be introduced into the system at low temperatures as might be experienced during normal generator shutdown conditions. Chemistry control will include vacuum deaeration, addition of hydrazine, and hydrogen over-pressure. It is believed that this will closely simulate the reducing conditions that would be expected during normal generator operations.

Samples in the lead test loops include both defective and non-defective tubing in order to assess both the initiation and propagation phases of intergranular stress assisted cracking. Tubes will be eddy current tested utilizing the .540" standard differential probe as well as a single coil absolute probe. The size and eddy current signature of the currently known defective tubes will be monitored and any changes in crack shape or eddy current signal will be closely watched. During the lead test, the tubes will be examined at the end of each test cycle (approximately every other month) and assessments will be made as to crack initiation or growth at each phase. In addition, at the end of each test cycle C-rings will be removed and destructively evaluated by metallography to assess the initiation of

any intergranular attack. Through this lead test program, an assessment can be made regarding plant operation in the unlikely event that crack initiation or propagation is observed.

To date, two lead test loops have been subjected to the hot functional test and three operating cycle simulations. Potential sulfur contamination in solution was simulated using sulfate in one loop and thiosulfate in the second loop. Tube specimens used were taken from unexpanded TMI-1 tubing. One loop used samples which were precoated with immunol. Both six-inch sec- tions and C-rings have been examined. No changes in preexisting eddy current indications were detected, and no intergranular attack was observed. The test loops are continuing through the remainder of the operating cycle simulations.

A third lead test loop simulated the hydrogen peroxide cleaning process, then continued through the hot functional tests and the first operating cycle simulation. Sulfur in solution is sulfate. All tube specimens used in this loop are six-inch sections of actual TMI tubing which have been Immunol coated and subjected to expansion process debris. Additional specimens which are representative of reactor coolant system materials have also been included in this loop. No intergranular attack has been observed. The test loop is continuing through the remainder of the operating cycle simulations.

The repair test loop, which uses single tube/tubesheet mock-ups, is being tested in a similar manner. The test sequence completed included the H_2O_2 cleaning cycle, hot functionals and the first operating cycle. All tubes were immunol precoated prior to expansion. After each test cycle, these tubes will also be eddy current tested on a periodic basis to monitor for new attack. No known defects were included into the repair test specimens. No intergranular attack has been observed. The repair test loop is now undergoing the second operating cycle simulation.

The long term corrosion test program will provide a means for making a comprehensive assessment of tube performance in actual generator operation over long periods of time.

E. Conclusions

Looking back at what has been learned about the TMI OTSG tube corrosion mechanism some conclusions can be drawn. Test results show that an active reduced sulfur species is required for low temperature damage to the Inconel 600 tubes. In the absence of this active species no crack initiation or propagation has been observed. Therefore, in the presence of clean borated water during normal

operation, one does not expect cracking. If for some unforeseen circumstance cracking would occur by reduced sulfur after return to operation, it would most undoubtedly occur when the system is open to air at low temperatures. Cracking at elevated temperatures under deaerated conditions will be governed by those mechanisms and parameters which could affect any operating generator in the industry. To further address the low temperature concern regarding the oxidation of reduced sulfur species in the tube surface film, lithium levels will be administratively controlled at higher concentrations than previously specified. Therefore, in the event there is formation of metastable sulfur species during an oxydizing transient lithium will be present to act as an inhibitor.

IV. PREVENTION OF RECURRENCE

A. Introduction

Steps have been taken to ensure that an aggressive environment could not be reintroduced into the RCS and cause additional damage. Prevention of direct injection of contaminants will be accomplished by administrative controls. In addition, the sodium thiosulfate tank had been removed. Chemistry changes have been made to include an analysis for sulfur, a conductivity consistency check which will indicate the need for reanalysis of samples, and an increase in the lithium concentration specification due to its inhibiting effect on crack initiation. In addition, to preclude reactivation of the sulfur which in the OTSG and RCS, a chemical cleaning program was conducted to oxidize and remove as much sulfur as possible from the RCS. This section discusses the steps taken to prevent recurrence.

B. Prevention of Future Chemical Contamination

Direct injection of foreign chemicals into the RCS during periods of operation is essentially limited to those substances which are placed into the Lithium Hydroxide Mix Tank or the Boric Acid Mix Tank. Injection through the reactor coolant bleed tanks during startup must also be considered. The probability of injection of a foreign chemical into the RCS from these tanks is dependent upon the administrative controls which are exercised over additions to the tanks.

When the RCS is cold and depressurized, additional paths for introduction of foreign chemicals exist. A path from the Caustic Mix Tank to the suction of the Decay Heat Pumps is one potential mechanism, and contaminants from the Borated Water Storage Tank and its associated piping systems is another. Since the sodium thiosulfate has been eliminated from the plant, and the line to the thiosulfate tank cut, sodium hydroxide is the contaminant which could be introduced via either of the described pathways. In the event that very dilute caustic did reach the tubes, damage would not be expected since increase in pH is toward a more benign condition. Introduction of other chemicals is prevented through administrative controls.

Administrative controls which are in effect include (1) clear labeling of tanks in the Chemical Addition Room, (2) locking open the breakers to pumps CA-P-2,3, & 4 and placing them under the administrative control of the Locked Valve and Component List and (3) review of applicable procedures to insure that adequate guidance is provided.

Since the range of chemicals which could be injected if administrative controls were to fail is wide, specific chemical analyses to detect the presence of the full range are not practical. However, because of its potentially deleterious effect on the OTSG tubes sulfur (as sulfate) will be sampled daily in the RCS. The other parameters which prove most useful in detecting ingress of un- wanted chemical species are pH and conductivity. These para- meters vary with lithium hydroxide and boric acid concentrations with possible conductivity values ranging from a low of approx. 2 micromhos/cm to a high of nearly 20 micromhos/cm and pH values from 4.6 to 8.5, depending upon operating conditions. Detection of inadvertent additions depends upon changes in either or both of these parameters which do not correspond to known additions, dilutions or treatment to the system. A consistency check on conductivity will be performed five times per week to confirm that the conductivity reading is consistent with the pH, boric acid, lithium hydroxide, and ionic species concentrations being measured. Specific analyses based upon the conditions under which the changes take place can then further define conditions.

The increased administrative controls, removal of the sodium thiosulfate tank and increased sampling requirements will ensure prevention or quick detection of unwanted chemical contamination of the RCS.

C. Changes in Operating Chemistry

Administrative primary water chemistry limits were implemented to prevent recurrence of the damage mechanism. This included an increase in the lower concentration limit for lithium due to its inhibiting effect on crack initiation and propagation, and an analysis for sulfur (as sulfate). A consistency check of pH and conductivity will be implemented. The check will improve our ability to detect the presence of potentially harmful ionic species. Table IV-1 shows the changes in the Primary Water Chemistry Administrative Limits.

1. The lower limit for lithium concentration was increased from .2 ppm to 1.0 ppm. This was done because lithium may have inhibiting effect on crack initiation and propagation.

2. Chloride was changed to meet revised B&W Water Chemistry Guidelines.

TABLE IV-1

THREE MILE ISLAND UNIT I

PRIMARY WATER CHEMISTRY ADMINISTRATIVE LIMIT CHANGES

PARAMETER	OLD SAMPLING FREQUENCY	NEW SAMPLING FREQUENCY	OLD LIMIT	NEW LIMIT
Lithium	NONE	Daily	0.2 - 2.0 (ppm)	1.0 - 2.0 (ppm) Varies with boron concentration
Chlorides	5X/wk	5X/wk	$\leq$0.15 (ppm)	$\leq$0.1 (ppm)
Sulfate, ($SO_4^{=}$)	NONE	Daily	NONE	$\leq$100 (ppb)
Sodium	NONE	2X/wk	NONE	$\leq$0.1 ppm
pH	5X/wk	5X/wk	4.8-8.5	4.6-8.5
Conductivity	5X/wk	5X/wk	NONE	Check for Consistency With Boric Acid and LiOH Concentration

3. Sulfur (reported as sulfate) was added to the Administrative Limits because of its deleterious effects on crack initiation and growth in Alloy 600.

4. Because sodium becomes easily activated and is an important contributor to total activity in the RCS, it will be monitored.

D. Cleanup of Sulfur from RCS

To preclude corrosion by sulfur contaminants already in the RCS, GPUNC conducted a chemical cleaning program to remove sulfur. Testing of a steam generator tube showed that near the outer surface of the oxide film, sulfur was predominantly present as sulfate. Further into the surface film, metal sulfides predominated.

The cleaning process was selected to chemically convert the metal sulfides on the steam generator tubing into soluble sulfates. In general, the process used in the plant was as follows:

- The RCS, Makeup and Purification System, and the Decay Heat Removal Systems were in use.
- Nitrogen added to the pressurizer vapor space was used to increase system pressure to approximately 307 psig
- Main coolant pumps were operated and cooling water flow through the Decay Heat Removal heat exchangers was adjusted so that the entire system operated at approximately 130°F ± 5°.
- When cleaning was initiated, the coolant contained a boric acid concentration between 1800 and 2300 ppm boron and lithium concentration of 1.8 - 2.2 ppm.
- Concentrated ammonium hydroxide (30 wt %) was added to increase the reactor coolant pH to 8.0 - 8.5.
- 3 wt % Hydrogen Peroxide was added to the RCS from the 4% boric acid mix tank via the core flood tank fill line and the pressure test connection on RCP "B" to establish a residual concentration in the range of 15 - 25 ppm. Since the peroxide decomposes, continuous additions were made as needed throughout the cleaning process to keep the peroxide in specification.

- The cleaning solution was continuously circulated. Cleaning took approximately 2-3 weeks. Termination of the cleaning process at 400 hours was based on developmental test results.

- The RCS sulfur cleanup behavior closely followed earlier laboratory simulations, with RCS sulfate concentration reaching a plateau at the end of 400 hours.

- Sulfate concentration after 400 hours was 0.4 ppm. The total sulfate picked up in the coolant was 0.33 lbs.

- Both the dissolved sulfate and the ammonia added were removed from solution by ion exchange resin in the normal purification systems.

A comprehensive test program was performed to determine the effectiveness of the cleaning process, and to verify that the conditions of cleaning would not introduce a corrosive environment. The program and results are discussed in a separate safety evaluation. Hydrogen peroxide appears to be effective in removing sulfur from both tubing surfaces and from inside crevices. Based on testing, 400 hours of exposure to the hydrogen peroxide solution is expected to have removed up to 80% of the sulfur which was present in deposits in the OTSGs.

E. Conclusions

GPUNC has implemented corrective actions in four areas in order to prevent recurrence of OTSG corrosion. The sodium thiosulfate tank has been removed from service to prevent additional inadvertent introductions of sulfur, and chemical cleaning was conducted to remove existing sulfur. Stricter administrative controls have been placed on introduction of other potential chemical contaminants. Stricter controls have also been placed on RCS chemistry to maintain a non-corrosive environment. These actions are expected to prevent contamination and corrosion by sulfur and by other chemicals.

V. KINETIC EXPANSION REPAIR DESCRIPTION SUMMARY

A. Description of Process and Geometry

1. Introduction

TMI-1 OTSG tube examinations have revealed a large number of tubes with defects within the upper tubesheet. A defect is defined as any eddy current indication interpreted as greater than 40% through wall. The limits of eddy current detectability are defined in Section IX. The repair approach is to establish a new primary system pressure boundary below these defects. A kinetic expansion of the tube within the tubesheet was used to effect this repair. All tubes which were not plugged were kinetically expanded irrespective of whether or not they have a defect, and irrespective of whether they were to be plugged following expansion. This repair provides a load carrying and essentially leak-tight joint below known defects. The following sections summarize the repair program. Details can be found in Reference 1 and Reference 23.

2. Kinetic Tube Expansion (Proprietary)

The process steps which are involved with this repair have the objective of providing a new pressure boundary below known defects through kinetic (explosive) expansion of the tube within the tubesheet. Extensive testing by Foster Wheeler has indicated that the most effective kinetic expansion technique for this repair is to use a 19 gr/ft initial shot followed by a second shot at 14 gr/ft. The charge is provided by a detonating cord held in place by a plastic insert. An electrical charge sets off a cap igniting the transfer cord which in turn fires a booster setting off the detonating cord.

Preliminary testing has determined that a 6" long expansion below the lowest defect will provide the desired load carrying margins. The expansion serving as the new pressure boundary is the bottom six-inches of a 17 inch expansion extending through the cracked area to the top of the upper tube sheet. Thus all tubes for which the lowest defect is at 11" or above have been provided with a new six-inch joint. Tubes with defects lower than 11" will be considered individually. Those with the lowest defect between 11" and 16" will be expanded using a 22" expansion. Those with defects lower than 16" below the top of the upper tubesheet will be taken o... of service.

The TMI-1 OTSG repair process is as follows.

Step	Description
1	Flush the secondary side tube to upper tubesheet crevice.
2	Heat crevice to drive out moisture (vaporize water).
3	Precoat tubes with Immunol
4	Kinetically expand tubes
5	Clean debris from kinetic expansion
6	Mill tube ends
7	Flush OTSG
8	Plug necessary tubes
9	Clean OTSG with felt plugs.

B. Design Bases of Kinetic Joint

The new joint comprises a kinetic expansion of either 17 or 22 inches which begins just below the upper tubesheet top surface in the area of the original shop roll expansion. The kinetic expansion will be the pressure boundary and structural attachment of the tube to the tubesheet.

The original OTSG design basis is summarized in Reference 1. The following is a summary of design basis for the new kinetically expanded joint.

1. The repaired tube shall sustain the maximum design basis axial tensile load of 3140 lb. from the generic 177 FA MSLB accident analysis. Since this is a thermally induced load, satisfying this criteria requires no relative movement (slippage) between the expanded area and the tubesheet at the axial strain corresponding to this load (about .0016 in/in).

2. Thermal/Pressure Cycles

   The initial design life objective for the tube kinetic expansion is 5 years.

   Sufficient cyclic testing and/or analysis will be performed during the qualification program to satisfy this objective.

A design life of 35 years has been established as a goal. Additional qualification testing has been performed which consisted of leak testing of specimens which had experienced cycling equivalent to a 15 year life. Specimens used were separate from those used to initially qualify the repair for a 5 year life. Assessment of the joint for the full 35 year design life will be performed when data on actual steam generator performance is available to supplement the results of the 5 year and 15 year test programs.

3. Tube Preload

The design objective stated in the original steam generator equipment specification for TMI-1 OTSGs was that the tubes not be in compression when cold.

The repaired tube tensile preload shall not be changed by more than ± 30 lbf at ambient temperature. This design objective is intended to assure that tube preload tension is maintained so that the vibrational characteristics of the tube will be unchanged for a preload change of this magnitude.

4. Residual Stresses

One design objective is to minimize tensile stress in the transition region between the expanded and unexpanded portions of the tube. Analysis shows that an abrupt transition results in higher residual stresses and larger stress concentrations. A transition length between 1/8" and 1/4" has been established as a goal.

An objective of maintaining additional residual tensile stresses (both circumferential and axial) resulting from kinetic expansion in the transition less than 45% of the .2% offset yield stress at room temperature has been established.

5. Heat Transfer Requirements

No credit is taken for heat transfer within the tubesheet.

6. Pressure Boundary Leakage

The original design basis for steam generator tube leakage was to provide generators with no detectable leaks at shipment and to control leakage to an acceptable operating level by monitoring and repair over the 40 year life of the plant.

The kinetically expanded joints used for repair of the TMI-1 steam generators are designed to be essentially leak tight. The expansion is designed to provide a seal below potential

leak paths in all tubes to be repaired. Tubes with unacceptable leakage as indicated by the precritical drip and nitrogen bubble tests (see Appendix A) may be roll expanded above the lower 6" to attempt to seal the leakage. If this is unsuccessful the tube will be plugged and/or stabilized if necessary.

For plant operation, primary-to-secondary steam generator leakage limits will continue to be set by the Technical Specification limit of 1 gpm. However, in order to control the amount of waste that requires processing, a design goal of 1 lb/hr projected total leakage from both generators has been set for the qualification program. Bubble testing can distinguish a leak that is of the magnitude of 0.1 gallons per day. An engineering evaluation of bubble test results as they relate to expected leakage will be conducted in order to determine what tubes require plugging. Statistical analysis will be applied to the verification test results.

C. Qualification Program

A series of mechanical tests and chemical and corrosion tests were performed to qualify the kinetic expansion, and the kinetic expansion process to meet the design goals of producing a joint capable of carrying required loads, providing a leak tight seal, minimizing residual stress, and tube preload changes. A series of preliminary tests was conducted to establish the optimum parameters for a kinetic expansion process that will yield acceptable joints with low residual stresses. Additional tests were conducted on a full size steam generator at B&W's Mt. Vernon Works. A more detailed description of the tests and results can be found in Reference 23.

1. Mechanical Tests

a. Preliminary Leak and Axial Load Tests (Proprietary)

Kinetic expansions were tested to determine the maximum axial load which could cause the expansion to slip. After a set of expansion parameters were postulated, leak rate and axial load tests were performed to determine whether the expansion would still appear adequate for a corroded tubesheet, after thermal and pressure cycling, and after adjacent tubes have been expanded.

The following acceptance goals were applied.

(1) Water leak at a pressure differential of 1275 psig (Primary to Secondary) 3.3×10^{-5} lb/hr per tube.

(2) Pullout load consistently above 3140 lb per tube.

(3) Margin in pullout loads and leak rate to account for possible deterioration of joint integrity from thermal cycling and for statistical analysis.

(4) Minimize expansion length.

(5) Minimize longitudinal strain induced in the tube by the expansion process.

(6) Minimize in-plane deformation of the expanded tube block hole and adjacent holes.

A 6" expansion using a 19 grain/ft insert followed by a 14 gr/ft insert gave acceptable preliminary results. Pullout loads for high and low strength tubing with the expansion as a function of the number of after-hits on uncorroded blocks showed pullout loads consistently in the 4000 to 5000 lb range for up to 4 after hits. Pullout load results for expansion on corroded blocks using corroded high and low yield tubing were consistently in the 4500 to 5500 lb range.

The effects of thermal and pressure cycling on pullout load were minimal.

b. Leak and Axial Load Qualification Tests (Proprietary)

These tests predicted the leak tightness and confirmed the axial load carrying capability of the chosen expansion technique, and showed what effect kinetic expansion will have on adjacent repaired tubes and determined the effect of re-expanding previously expanded tubes.

Seven blocks were thermally cycled as follows:

38 cycles 70°F to 610°F to 70°F

One block was then exposed to a series of load cycles. These were:

100cycles	780 lbs. compression to 1110 lbs. tension
180 cycles	635 lbs. compression to 175 lbs. tension
6000 cycles	510 lbs. compression to 125 lbs. compression

Cycles selected correspond to the 5 years qualification period.

The majority of leak and slip load qualification testing was performed at room temperature with the exception of one block loaded at 330°F and one block leak tested at 400°F.

Acceptance criteria required that a statistical evaluation of the results show a 99% confidence level that 99% of all tubes expanded would have a pullout load greater than 3140 lbs. A mean leakage rate goal of less than 3.2×10^{-5} lbs/hr/tube was desired.

Results indicate that thermal cycling tends to decrease pullout load, however thermally cycled blocks pulled at 70°F gave a 99% confidence level that 99% of the tube expanded will have pullout loads in excess of 4170 lb. One block which was pull tested at 330°F gave 99/99 statistical confidence that pullout load would be in excess of 3590 lbs. The goal of 99% confidence that 99% of the tubes have pullout above 3140 lb is easily met. In addition, an expansion pull test performed on a full scale generator at Mt. Vernon showed a load carrying capability of at least 3600 pounds.

Leak rate results after thermal cycling equivalent to 5 years vary from 1.18×10^{-6} to 187.4×10^{-6} lbm/hr/tube. The average tube leakage was considered to be one-tenth of the total test block leakage in each case. Statistics indicate a 99% confidence that 99% of the normally expanded tubes will have leakage rates no greater then 132.4×10^{-6} lbm/hr/tube. While this rate exceeds the design objective of 3.2×10^{-5} lbm/hr/tube, it is still a very low leak rate. Results of leak rates after axial loading are found in Reference 23. If every tube in both OTSGs leaked at this maximum rate the cumulative leak rate would still be less than one-hundredth of the Technical Specifications limit of 1.0 gpm. The leak rate of the one block showed an increase between 10°F and 400°F (6% of the total range of leak rates) leading to the conclusion that the leak rate for a tube at operating temperatures would differ only slightly from what it would be at room temperature.

Leak rate results after thermal and load cycling equivalent to 15 years vary from 31×10^{-6} lbm/hr/tube to 68×10^{-6} lbm/hr/tube. This 15-year test data is comparable to the 5-year test data with no indication of joint leakage increasing due to thermal and load cycling.

c. Residual Stress Testing (Proprietary)

(1) Preliminary Transition Geometric Limitations

This test determined the expansion parameters which would lead to a transition that would minimize the transition residual stress and stress concentration factor. It was concluded that a transition length between .125 and .25 inch would be a goal, with a minimum acceptable transition length of .1 inch. A number of insert shapes were evaluated to determine which provided a smooth transition.

A 30 degree taper on the end of the polyethylene insert was found to provide the optimum transition.

(2) Residual Stress Measurements

The actual residual stress was measured in special test blocks using X-ray diffraction and strain gage techniques to determine post-kinetic expansion tube stresses in the transition area at the bottom of the expansion and at a second point near the middle of the expansion. Both hard rolled and kinetically expanded tubes were examined using high and low yield strength materials.

The goal for this test was that the additional residual stress in the tube resulting from kinetic expansion would not exceed 45% of yield strength.

Results are reported in Reference 23.

(3) Comparison of Kinetic and Roller Expansion

Sample Inconel 600 tubes were expanded by rolling and kinetic processes in order to compare the resulting hardness and microstructure.

Both processes increase the hardness, with the roller expansion showing a greater hardness (100 to 103 R_B equivalent) than the kinetic expansion (92 to 93 R_B). The roller expansion tends to harden the inner surface more than the outer, while the kinetic expansion is slightly harder at the outer surface. Prior to expansion the tube was significantly harder on the outer surface. Since the hardening effect in the mechanically expanded tube is more pronounced and less uniform than in the kinetically expanded tube, the kinetic expansion may be expected to be less susceptible to stress-corrosion cracking than mechanical expansion.

(4) Corrosion Testing of Transitions

Accelerated stress corrosion cracking tests were performed on expanded tube/tubesheet mockups. The mockups were tested in 10% sodium hydroxide (NaOH) at constant potential and destructively examined for stress corrosion cracking (SCC) due to residual stresses from the repair expansion process. The results were compared to existing data on tubes that have been stress relieved after expanding. Two test configurations were used; the first was an Inconel 600 tube kinetically expanded in the tubesheet, the second was an Inconel 600 tube kinetically expanded plus a hard roll in the expanded region.

Test results show no evidence of cracking.

d. Induced Strain Tests (Proprietary)

Tests were performed to determine the effects of the expansion on the tube-to-tubesheet welds, and the tube length, and to determine the strain stored in the expansion. A design goal of changing the preload by less than ± 30 lbs due to elongation was applied.

Results show that kinetic expansion has a minimal effect on the overall longitudinal tube strain and as-fabricated preload. Induced strain measurements taken before and after expansion indicated maximum longitudinal strain values of less than .04 percent. This relates to a reduction in tube preload of about 16 pounds, which is considerably less than the 30 pound design limit.

In some cases, prior to expansion, the degradation of the tube in the area of the seal weld allowed the tube to slip down, relieving all or part of the preload. These tubes were then expanded.

These tubes have been evaluated to determine the potential effects of loss of preload, and are discussed in Section VI-E.

e. Ligament Distortion (Proprietary)

The effects of explosive expansion on the tubesheet ligament were determined. The dimensions of adjacent holes in the tubesheet were measured before and after the expansion and compared.

Results show that only a minimal effect was noted in the diameter of adjacent holes due to tube expansion using charges between 25/14 and 14/14.

Full scale testing in a steam generator at Mt. Vernon using strain gages and profilometry showed no degradation of the tubesheet ligaments.

Based on the mechanical qualification tests it can be concluded that the kinetic expansion joint will meet the five year design life objective. The repaired tube will sustain the maximum design basis axial load of 3140 lbs., residual stresses will be minimized, tube preload will not change more than ± 30 lbf, and leakage will be much less than technical specification limits.

2. Chemical and Corrosion Testing

a. Residue Test (Proprietary)

The amount and type of explosive residue that should be expected to remain in the steam generator after all tube repairs are completed was determined. A satisfactory cleaning method to reduce contaminants to acceptable primary system water chemistry levels was identified.

Results show that the chemical composition and amounts of the residue are acceptable. The use of ordinance transfer cord minimizes the amount of debris in the upper head.

Techniques for cleanup of the tubes after kinetic expansion will include felt plug wiping on the inside of the tubes and water flushing the top surface of the upper tubesheet, tubes and the inside of the upper head. To enhance the water flushing, all primary side surfaces exposed to kinetic expansion residue will be coated with a film of water soluble Immunol X-236.

b. Crack Change Tests (Proprietary)

The effect of kinetic expansion on existing cracks was determined.

Explosive expansion using 25 gr/ft cord was found to cause no damage to the base metal, although existing cracks were found to be slightly separated so as to become more visible.

Double expansions using 19/14 were done on several samples from TMI-1 steam generator and on sulfur induced laboratory grown IGSAC cracks that were less than through wall. Neither through wall nor less than through wall cracks propagate circumferentially or

through wall. They are however slightly widened to become more visible. There is no evidence of any ductile tearing of tube material.

c. Effects on Residual Sulfur

Testing was performed to assess what happens to the sulfur on the surface of steam generator tubes (i.e. driven into the base metal) after kinetic expansion.

It was determined that the sulfur concentration on the tube I.D. in the area of the kinetic expansion does not change, that it is not driven further into the base metal, and that the expansion does not significantly alter the grain boundary structure in a way that would trap sulfur.

D. Repair Testing

The in-process inspection and monitoring program was designed to verify that the in-generator expansions are similar to those obtained in the qualification program. Actual OTSG expansion profilometry and ECT results were compared to test program data to verify that the expansions are similar. Data obtained from TMI-1 was also compared statistically to test program data. The program consisted of video surveillance, profilometry measurements, and eddy current (ECT) examinations.

Video surveillance of operations during the expansion process were conducted where practical to verify that proper procedures were followed and that the correct tubes were expanded or examined. Random out-of-generator expansions were also conducted to verify that expansion inserts had not changed since the qualification program.

Verification sampling was performed on the tubes expanded by the initial charge strength in the first three lots in each OTSG and consisted of ECT and profilometry. ECT using an 8x1 probe was performed on almost 100% of the tubes expanded in the first lot in both OTSG's. Profilometry was performed on expanded tubes selected at random from the first three lots.

In addition to verification sampling, random diameter and depth checks sampling were done following initial expansion. The sampling plan can be found in Reference 19.

Results are presented below of both the expansion length inspection program and the program to verify that each tube was expanded as required.

1. Results of the Expansion Length Inspection Program

Out-of-generator expansions indicated that the process expansion inserts and detonating materials performed as those used in the qualification program. Profilometry and diameter and depth gauge checks showed that the in-generator expansions were within the range of variation of the qualification program expansions. In addition, eddy current examination using the absolute (8x1) probe was conducted for the first lot of kinetically expanded tubes in both steam generators. The 8x1 absolute probe has been chosen for this in-process monitoring in the newly expanded area because the coining process of the expansion creates so much background noise that the .540" standard differential probe is not useful following kinetic expansion. The 8x1 absolute probe provides 360° coverage. A judgement concerning defect arc length can be made depending on how many coils of the 8x1 probe detect an indication. Laboratory testing has shown that a 1 coil indication can have an arc length of 5° to 40°, a 2 coil indication has an arc length up to 85°, and a 3 coil indication has an arc length up to 130°. Although the 8x1 absolute probe can be used to quantify the circumferential extent of a particular indication, it cannot be used to accurately determine the percent thru-wall of the indication. The scope of the examination included 151 tubes in OTSG B and 284 tubes in OTSG A. The eddy current data was analyzed from the top of the 6" qualification length for kinetic expansion down through the bottom of the upper tubesheet. As a result of this data evaluation, 9 tubes in OTSG B and 6 tubes in OTSG A were reported as having indications which had not previously been detected by the .540" OD high-gain standard differential probe.

These new 8x1 ECT indications were evaluated to determine their significance. The evaluation included 1) Fiberscope examination of selected tube areas where indications were detected, 2) Comparison of the size of any visual indications to the ECT sensitivity curves, and 3) Laboratory metallographic and ECT examination of known cracks which had been expanded. The following was concluded from this evaluation:

1. The only visual evidence seen which correlates with the ECT indications is small pits and a mechanical scratch.

2. Laboratory expansion of known cracks confirms no growth (no ductile tearing) and indicates no change in 8x1 ECT signal from known cracks.

3. If some of these ECT indications are from small cracks which were previously below the .540 ECT sensitivity within the upper tubesheet (UTS), their geometry is so small that the reliability of the new joint is not affected.

4. The most probable reason for these new indications is that the 8x1 probe is more sensitive than the .540 probe within the UTS. The 8x1 probe appears to be sensitive enough to respond to pits which are so small they are of no consequence.

Section IX documents extensive work done to evaluate the maximum size crack which can be left in service for the life of the plant and not cause tube failure under normal or accident tube loadings. Acceptable circumferential extent vs. throughwall depth curves for various loading and analysis conditions in the free span are shown in Figure IX.2. The pit indications found in the area of the joint are smaller than the crack size leading to failure by any mechanical means in the free span. These curves are conservative for indications in the joint since loads imposed on the tubes are transmitted to the tubesheet in the area of the expansion. Loads on tubing in the area of the defects will be equal to or less than those analyzed for the free-span. Leakage through any small defects which are 100% throughwall is also expected to be less than or equal to similar cracks in the freespan. Unacceptable leakage will be identified during precritical testing and the tube will be either plugged or repaired. For these reasons, it is concluded that small pits or undetected cracks in the qualified area do not affect the reliability of the new joint.

It is expected that additional indications will be identified during the baseline 8x1 eddy current examination of the expanded region to be conducted following the kinetic expansion. These indications will be evaluated to confirm that they are acceptable, and will be left in service and re-examined during the 90 day ECT program.

2. Identification and Expansion of Misfires (Proprietary)

Inserts which did not fire were generally easily identifiable because they remained in the tube. However, during the 19 grain/foot expansions several misfired candles were ejected from the tubesheet. The locations of these were found using a diameter gage to determine which tube in that sequence was not expanded. Because there is no measurable

change in tube diameter caused by the addition of a 14 grain/foot expansion this technique could not be employed during the second round of expansions in the event of an unidentified misfire. The cause of ejected misfires was thought to be a whipping action of the ordinance transfer cords in which sufficient kinetic energy was imparted to the cords by the rising candles to pull a misfired candle from the tube. Devices were made to lock the transfer cords to the tubesheet in order to prevent the occurrence of "jumpers."

In spite of precautions taken, "jumpers" occurred in several separate instances. In these instances the tubes of the previous sequence were reexpanded with 14 grain/foot devices to assure that the "jumpers" had received 14 grain/foot expansions. This was done in such a manner that no tubes ever received more than 4 after hits (the maximum number presently technically justified for normal tubes). However, during one expansion sequence in the "B" generator a misfired candle was discovered under some shielding. The sequence to which that candle belonged could not be identified and the misfire loc ion could not be defined more precisely than one of the first 7000 tubes done in that generator.

The concern for a singly expanded tube is that, potentially, being unable to carry sufficient axial load, the tube would fail, slip downward and lock. Therefore, an evaluation was performed to determine the likelihood of slippage during operation, and the potential consequences if the singly expanded tube were plugged, stabilized or left in service.

A statistical evaluation of available data for single 20 grain/foot expansions from pre-qualification testing showed a 99/97.5 confidence interval that no slippage would occur under normal or accident loading. While the data used is for 8" expansions and for expansions receiving many less after hits than a typical singly expanded tube would receive in the generator, the resulting high confidence is felt to be indicative of what would be expected if a test program using more correct configurations were performed. Actual pullout strength will be dependent on the location and size of cracks in the singly expanded tube. Leakage data for tubes with one expansion is available from the preliminary qualification program for a defect free length of 8". For this length, leakage is expected to be sufficient to be identified during precritical testing. Similarly, leakage will be greater the shorter the defect free length. In addition, the tight annulus between the tube and tubesheet will provide a substantial restriction to any leakage.

In the event that the single expanded tube will remain in service, then slip under transient or accident conditions, effects of slippage were evaluated. Assuming a minimum 6" leak length and a worst case 0.001" radial annulus, the leak rate past the expansion would be about 0.25 gpm or one quarter of the Technical Specification limit. This annulus size is considered to be conservative because any actual leak path past the expansion is expected to be a discrete path such as a scratch. A leaking tube would be located by conventional means and would be plugged and, if necessary, stabilized.

Of the approximately 7000 tubes which could have been the single expansion site, only about 100 were to be plugged. Slippage of a plugged tube could not be identified due to leakage. Thus if the tube slipped and locked, it could bow or be dynamically unstable in cross flow areas and cause wear damage to adjacent tubes. Approximately half of the plugged tubes will be stabilized, which should prevent wear damage. The remainder are in areas of minimal cross flow, so dynamic instability should not be a problem. Even if the single expanded tube were one of these, and it slipped enough to bow under operating conditions, a relatively small point load against the neighboring tubes or tubesheet could force a node at the point of contact and prevent wearing.

Based on these evaluations, it was concluded that the likelihood was small that a single tube expanded only once would be located in an area which might result in problems, and would then slip with loading. Therefore, no further actions were taken.

E. Post Repair Testing

Following repair, testing will be performed to verify the acceptability of the joints. Post Repair tests include:

1. 150 psig bubble test. Upper tubesheet plugs, tubing and expansions leak test.

2. 150 psig drip test. Lower tubesheet plugs, tubing and expansions leak test.

3. Hot OTSG Testing

   Hot OTSG testing will include transients that will place operating loads on the new joint. These transients will include:

a. normal cooldown
b. accelerated cooldown
c. normal cooldown using modified tube rupture emergency procedure

Leakage will be monitored before, during, and after the transients. A 1400 psid operational leak test will also be conducted. A more detailed explanation of the testing programs can be found in Appendix A.

The cold testing described in items 1 and 2 above has been completed. The results are discussed in Appendix A. Based on the drip and bubble tests, and investigative ECT inspection, GPUN concluded the following. With the possible exception of four tubes which bubbled only slightly and were not investigated further during stopper testing or by ECT, all leakage was found to come from below the top of the qualification length of the kinetic expansion joint. No joints were found to leak.

F. Conclusions

Based on a qualification program, the kinetic joint meets or exceeds the design bases of the original joint, including the following factors:

a. Load-carrying capability.
b. Tube preload.
c. Minimization of residual stresses.

Leakage is projected to be less than one-one hundredth of the technical specification limit of 1 gpm. Kinetic expansion in the upper tubesheet is a safe and reliable method of repair for all tubes that will remain in service in the TMI-1 steam generators. The tube joints will remain structurally sound and essentially leak-tight during all design conditions over at least a five year period.

VI. EFFECTS OF EXPANSION REPAIR

The possible effects of the kinetic expansion process with respect to introduction of chemical impurities, the effect on the OTSG structure, the effect on tubesheet corrosion characteristics and the effect on existing plugs have been evaluated.

A. Possible Introduction of Chemical Impurities

The specification for OTSG tube repair addresses the issue of impurities in the system. It specifies that the inside of the steam generator will not be exposed to materials containing more than 250 ppm sulfur and 250 ppm total chlorides and fluorides, and specified detectable amounts of low melting point metals. Required deviations will be addressed on a case basis. A material control program with quality controls was required for confirmation that material is not introduced inside the steam generator without assurance that its constituents are known and acceptable was implemented.

The large majority of the debris was demonstrated (testing in mockups and a full-scale OTSG) to be particulate matter. The large particulate debris was removed by manually picking up pieces by hand, and by vacuuming in both the lower and upper heads. Particulate debris in the tubes was removed by forcing felt plugs through each tube.

In addition to the easily removed particulate debris, laboratory tests showed a thin layer of material was deposited on the exposed OTSG surfaces. This film consists primarily of carbon, identified as polypropylene. The amounts of contaminants, sulfur and other elements, in this layer are low (traces only). In order to minimize the potential for the film interfering with a subsequent sulfur removal treatment, steps were taken to minimize film thickness. The OTSG surfaces were coated prior to expansion with a substance which, when flushed with water, reduced the film thickness significantly.

This residual film is not uniform over the length of the tubes, being thickest nearest the expansion. The results of tests show a remaining layer, after flushing, which averages 50 Angstroms thick over the length of the tube. A similar condition should exist at the top of the tubesheet surfaces and the inner surfaces in the dome of the upper head.

As a worst case, it may be assumed that the 50 A film on the 31,000 tubes melts as the reactor coolant approaches operating temperature. The polypropylene is not soluble in hot water, but

the high velocity coolant through the tubes could entrain particles as they soften and lose film tension on the tube surface. The turbulant reactor coolant flow would carry these minute droplets of molten plastic throughout the reactor coolant system as a very dilute emulsion of about 0.44 ppm polypropylene. The demineralizers and filters in the letdown system would gradually remove this slight impurity from the reactor coolant. Industry experience shows that there may be a tendency for the molten droplets to collect in relatively stagnant areas of the reactor coolant system. The reactor head would be the most likely area of concentration, and during cooldown the polypropylene may solidify as a film on the under side of the dome. In the unlikely event that the total volume of plastic were to separate out in the head area, the CRDM lead screws would collect a negligible amount of residue.

Should there be a reactor cooldown, any molten droplets remaining in the coolant would tend to solidify as a film on the coolest surface available. Both the letdown and decay heat systems will be cooling portions of the reactor coolant and the polypropylene would redeposit as a thin film on the letdown and decay heat cooler tubes. The hot surfaces in the core are the least likely places for the plastic to solidify. There is no reasonable assumption which would indicate the half cup volume of plastic film could cause a problem before it is removed from the system.

B. Possible Effects on OTSG Structure

It has been postulated that the kinetic expansion may, because of the large number of tubes involved, have significant effects on the steam generator as a structure as well as on the individual tubes.

For individual expansion, evaluation of the tubesheet ligaments has shown no significant effects of expansion. It was postulated that with multiple kinetic expansions there could be a shock wave reinforcement such that the sequence of explosions or the length of the prima cord should be controlled to insure that the tubesheet is not overstressed. The concern was that the shock wave may travel at about the speed of sound through the material, and if adjacent tubes exploded in a manner such that their shock wave reinforces shock waves from other tubes, there could be a condition where the tubesheet is overstressed.

Testing was performed in the steam generator at Mt. Vernon using strain gages and an accelerometer to demonstrate that the coincident explosions of the maximum number of tubes to be expanded

at any one time was acceptable. This was done by exploding 132 charges in the longest row in the generator. A maximum stress intensity of 95,000 psi at 800HZ was obtained at the strain gage closest to the expanded row. This compares to a static yield strength of 70,000 psi for the tubesheet material. Since the yield strength of steel increases markedly at high strain rates (up to twice static yield) and that no residual strain was measured on the strain gauges following expansion it is concluded that no plastic deformation occurred. The maximum stress intensity recorded for the weld between the tubesheet and shell was less than 10,000 psi. The strain gauge on the tube recorded very low values indicating that no significant excitation of the tube bundle occurred. A fatigue analysis has been performed and the tubesheet at the periphery was found to be limiting. The analysis was conservative in that it assumes that the principal stresses occur simultaneously and that all blasts yielded the same peak value. The other strain guage locations clearly show that the stress diminishes as the distance from the expansion increases. The results was a maximum fatigue usage of .12. From this data it was concluded that the use of up to 137 charges is acceptable and the total number of separate blasts will not present a fatigue problem.

In addition, Foster Wheeler has kinetically expanded over 2000 feedwater heaters and expanded as many as 5000 tubes in a heater in one detonation. They report that they have never experienced any tubesheet overstressing problems and do not believe this is of concern since the plan is to expand only 132 tubes simultaneously plus any misfires from the previous row up to a total of 137 total tubes for the TMI-1 Steam Generator repair.

The combination of Foster-Wheeler experience and the strain gage data show the explosive expansion process to have no adverse effect on the steam generator.

C. <u>Corrosion</u> (Proprietary)

Several concerns have been addressed relative to the susceptibility of the repair to corrosion. In tubes with through wall cracks, a leak path for primary system water may still exist even after kinetic expansion over the full 17 inches. The breech exposes the carbon steel tubesheet wall to the corrosive effects of a buffered solution of boric acid, i.e., clean reactor coolant.

As described earlier in this report, ID tube cracking due to the corrosive effect of sulfur and/or sulfur containing ions has been identified as a probable contributing cause of the TMI-1

steam generator problems. The first concern is therefore residual sulfur deposits in crevices above and below the repair seal area, particularly in pockets that may have resulted from corrosion of the tubesheet wall. Such deposit could cause an attack on the Inconel tubing. Sulfur attack would be preferential to the Inconel rather than the carbon steel tubesheet. It is presumed that the source of sulfur contamination no longer exists and the RCS is essentially sulfur free. As in the original design, a crevice will exist below the seal between the OD of the Inconel tube and the carbon steel tubesheet wall. The crevice has been flushed to reduce soluble deposits, particularly in the crevice area below the repair seal.

Several years ago model boiler testing was performed at B&W Alliance Research Center in support of a repair to a Florida Power Corp., Crystal River 3 Steam Generator. While these tests dealt with damaged tube to tubesheet welds rather than intergranular tube fractures, several conclusions applicable to the TMI-1 repair program can be drawn. They are:

1. Iron oxide formation, probably the result of tubesheet corrosion in the tube-tubesheet crevice, plugged the leak path of an intentionally damaged tube. Under ambient conditions, the oxide was less tightly packed and the leak path remained slightly open. Under boiler operating conditions of high temperature and pressure, the oxide became more tightly packed and appeared to further plug the leak path.

2. There was no perceptible evidence of tubesheet hole corrosion in the tubesheet bore area of the removed tube section. (The Mark II model boiler was operated for 6,448 hours.)

The leak paths in the model boiler tests were generally larger than those noted at TMI-1. Therefore, the self-sealing mechanism noted above should be enhanced in the TMI-1 generators. This sealing mechanism along with the kinetic expansion tends to severely reduce the possibility of free circulation of reactor coolant in the upper crevice area which could produce an aggressively corrosive environment.

Fibre optics inspection of the TMI-1 generator tubesheet (video tape is available) showed pitting of the tubesheet wall to be very minimal reducing the likelihood of significant pockets of sulfur deposit being present in the crevice above the seal that could corrosively degrade the seal repair. The packing property of the iron oxide noted in the model boiler test also works to limit the possibility of existence of an aggressively corrosive environment due to the presence of small sulfur deposits.

Based on the test results, tubesheet inspection and planned crevice flushing, extensive corrosion of the tubesheet by residual sulfur deposits or reactor coolant is considered highly unlikely.

D. Effects of Expansions on Existing Plugs

The TMI-1 OTSG tubes have been taken out of service by four different procedures:

1. Explosively welded plugs - Plugs inserted into the tube and explosively welded in position within the tubesheet.

2. Welded plugs - Plugs welded to the tube ends or tubesheet at the top of the upper tubesheet.

3. Hydraulically expanded tubes sealed with a welded plug - tubes that have been immobilized by expansion after a short section of the tube within the tubesheet was removed. The tubes were then taken out of service by installing welded plugs in the tubesheet openings.

4. Mechanically rolled plugs.

B&W has evaluated the effect the forces of the kinetic expansions may have on the integrity of the first three of these plugs and expansions and has concluded the kinetic expansions will not affect their mechanical integrity or leak tightness.

Tests of the kinetic expansion process in steam generator model test blocks with conditions simulating those in the TMI-1 steam generators show that the kinetic expansion does not produce any permanent tubesheet ligament deformation. This leads to the conclusion that plugged tubes adjacent to kinetic expansions will not be altered by changes in the tubesheet ligament, since no permanent change is noted.

During additional tests on an actual OTSG, B&W examined, by dye penetrant tests, the tube-to-tubesheet welds and tubesheet ligaments of the kinetically expanded tubes and the tube-to-tubesheet welds adjacent to expanded tubes and have not seen any degradation.

Thirdly, the extensive laboratory and field experience of B&W with explosive plugging tubes in operating steam generators indicates that damage to plugged tubes due to detonation of explosives in adjacent tubes does not occur.

Tests were performed on qualification blocks with rolled plugs in place and explosive expansions of all adjacent tube locations. Leak rate and axial load tests were done to verify that the rolled plugs continued to meet the acceptance criteria to which they were originally qualified for use.

Lastly, a pre-operational post-kinetic expansion pressure test of each generator was performed to verify the integrity of the primary to secondary pressure boundary thus providing added assurance that the plugged tubes have not degraded. All unacceptably leaking plugs were repaired or replaced.

E. Relief of Preload

In some cases, prior to expansion, the degradation of the tube in the area of the seal weld allowed the tube to slip down, relieving all or part of the preload. The tubes were then expanded.

GPUN examined the effects of changing preload with respect to the limiting transient and accident loads on the tube. (Ref. 60) The maximum compressive load under FSAR accident conditions is a 620 lbs. load associated with a feedwater line break. The approximately 775 lb. generic design basis compressive load associated with a 100°F/hr heat-up proves to be the limiting case. We understand that B&W generic calculations assume a preload of not more than 100 lbs. tension. Thus, for a tube with no preload, 875 lbs. is the maximum compressive design basis load expected under normal, transient or accident conditions. However, measurement of the gap left at the seal weld following relief of preload confirms up to 280 lbs. of preload may have been lost in some peripheral tubes at TMI-1. For conservatism, an evaluation was performed of the ability of a tube to withstand 1025 lbs. of compressive load. This is a conservatively large loading since actual heat-ups are conducted at rates well below 100°F/hr and the 1025 lb. load value is considered conservative for a 100°F/hr heat-up transient.

Buckling is not expected to occur under this load. Tube bowing is limited by the small clearances of the tube support plate holes. Further, the applied load is secondary in nature; it is caused by thermal differential expansion. As the tube begins to bow under the loading, the magnitude of the load is reduced. Thus, a non-preloaded tube will not be overstressed by the transient load conditions.

GPUN has also examined the magnitude of lateral displacement to be expected in a tube loaded compressively to 1025 lbs. The magnitude of the lateral displacement in the 16th span of the tube will be the largest since that span is longest, but all of the spans will contribute in relieving the load. Displacement magnitude will also be dependent in part of the initial curvature of the tube. Lateral displacement nominally less than the dimensions of the gap between tubes, even under transient conditions, is expected as a result of the loss of preload. However, even if tubes were to contact each other, no problem is expected. During a heatup transient, flow rates are very low and the time duration is relatively short; no significant tube vibration or wear would be expected.

GPUN has also considered the effects of the change in preload on the natural vibration frequency of a tube. A non-preloaded tube is expected to have a natural frequency about 15% lower than one preloaded. The effect of this frequency reduction is considered small. EPRI has reported that other operating plant steam generators have variations in tube frequencies of as much as about 10 to 20% within a single steam generator. In addition, test data reported by EPRI shows that another OTSG plant now operating has tube frequencies about 15% lower than those of the tubes at TMI-2. If, as expected, the TMI-1 tubes have approximately the same preload as those as TMI-2, then the tubes at the other plant mentioned above have about the same frequency as the unloaded TMI-1 tubes. Accordingly, no problem is expected at TMI-1 due to non-preloaded tubes.

Based on the above described evaluations, GPUN has concluded that the relief of preload in some of the steam generator tubes does not render them unacceptable for continued use.

F. Conclusions

Based on the above evaluation and testing, the kinetic expansion process will have no adverse effect on the OTSG structure, tubesheet corrosion, or plugs previously installed. In addition, a cleaning process has been used to remove the residue from the expansion process. In conclusion, overall there are no adverse effects from the kinetic expansion process.

VII. PLUGGING REPAIR DESCRIPTION SUMMARY

A. Introduction

Those tubes which have defects below the 16" from the primary surface of the upper tubesheet (US) and could not be recovered and returned to service by the above described Kinetic Expansion repair were removed from service by plugging. A defect is defined as any eddy current indication interpreted as greater than or equal to 40% through wall. For conservatism, any less than 40% I.D. indication identified during the 1982 record examination with a large enough circumferential extent to be detected on three or more of the eight coils of the absolute probe was treated as a defect for plugging purposes. The limits of eddy current detectability are defined in Section IX. There are a total of 2[illegible]9 tubes in A and 88 tubes in B OTSG that were plugged with either Westinghouse rolled plugs or B&W welded and explosive plugs prior to kinetic expansion. An additional 658 tubes in A and 199 tubes in B OTSG have been removed from service by plugging since kinetic expansion. 19 tubes in A and 10 tubes in B steam generator which have been cut and removed for metallurgical examination were plugged with a B&W welded tapered cap on the top and an explosive plug at the bottom tubesheet. Defective tubes in some locations were stabilized as indicated in Table VII-1. 680 tubes were stabilized. The purpose of tube stabilization is to minimize the risk due to propagation of tube defects located in regions with high potential for flow induced vibration resulting in circumferential tube severence and causing damage to adjacent tubes or creating loose parts. The lower tube end was plugged with an explosive plug or a Westinghouse roll plug. The following sections give an evaluation of the methods selected for tube plugging and stabilization, and a description of the types of plugs to be used.

B. Types of Plugs

1. B&W Welded Tapered Plug, Welded Cap, Stabilizer and B&W Explosive Plug

B&W Welded Tapered Plug is used to plug the bare upper tubesheet hole for tubes where the tube end has been removed. B&W's welded cap is used to seal the upper tube end for those tubes which will be plugged and stabilized. Prior to installing the weld cap, the existing tube end is machined off leaving a portion of the tube end and the existing weld protruding above the tubesheet surface. The weld of the nail cap fuses with the existing seal weld, providing the desired pressure boundary.

B&W Explosive Plug is used to plug LTS tube ends where B&W plugs are used in UTS. Both B&W plug types MK-1 and MK-3 have been qualified for OTSG tube plugging and used in the operating B&W units.

B&W standard design stabilizer rods are threaded onto the welded cap to form a stabilizer assembly of the desired length. The stabilizer is a multi-piece assembly of solid rod made of Inconel SB-166. Joint tightness is maintained by crimping the pieces together beyond the threaded sections. The segment length is dependent upon the tube bundle location.

B&W welded tapered plugs, welded cap, explosive plugs and stablizer rods have been previously qualified see References 30 through 35.

2. Westinghouse Rolled Plugs

Westinghouse plugs were designed for a primary pressure of 2500 psi and 650°F and a secondary pressure of 1050 psi and 600°F. Cracks in the roll transition or the area of the seal weld do not exclude the use of Westinghouse rolled plug.

The Westinghouse rolled plug is machined from bar stock that has received a thermal heat treatment which has been demonstrated by laboratory testing to have improved resistance to intergranular attack in caustic and polytheonic acid environments, compared to treatments at different temperatures and times.

The Westinghouse Roll Plug Qualification Program for TMI-1 has been completed for a 5 year life, and results are documented in Westinghouse Report WCAP-10084.

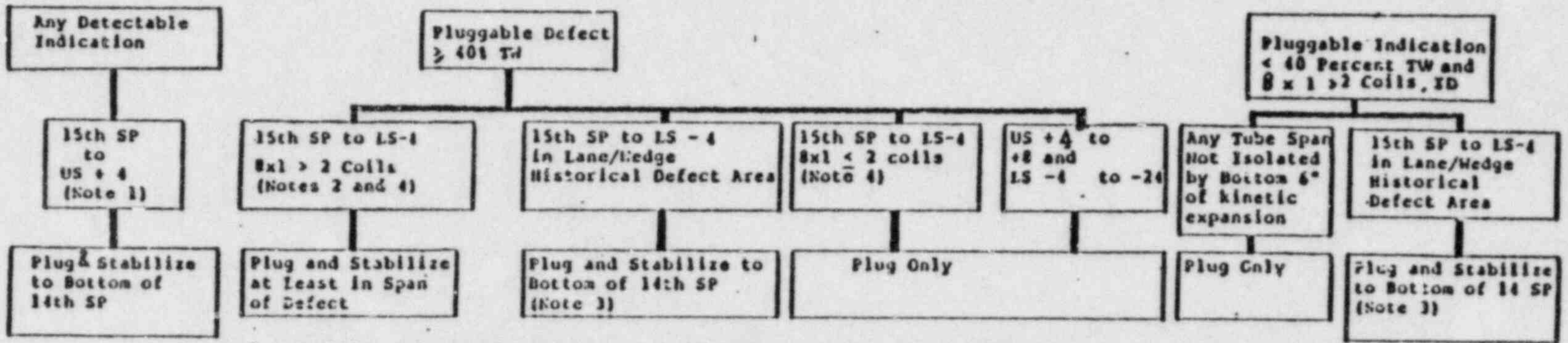
C. Plugging and Stabilization Criteria

Final tube plugging and stabilization criteria were selected to minimize the possibility of cracks propagating to a size which could part under stress conditions, either plugged or unplugged tubes. Analyses presented in Section IX show that the vibrational effects of cross flow are not expected to contribute to crack growth in an unplugged tube. However, as a precautionary measure, plugged tubes with defects in the area of highest cross flow, between the 15th support plate and US+4, are stabilized. In addition, stabilizers have been used where eddy current indicates a crack of significant size in historical defect areas, and below the 15th support plate where I.D. xl indications are greater than 2 coils. Measures to monitor for crack propagation due to flow-induced vibration or other means, including leakage

VII-1

OUTLINE OF BASIC TUBE PLUGGING/STABILIZING PLAN

FOR INDICATIONS IDENTIFIED
DURING 1982 RECORD INSPECTION



1. Includes tube sections from bottom of 15th support plate to 4-inches up into bottom of upper tubesheet.
2. Include: tube section from bottom of 15th support plate to 4 inches down from the top of the lower tubesheet.
3. See Figure VII-2 for tubes in Lane/Wedge area.
4. 8x1 is ECT probe with 8 absolute coils

monitoring (Section X) and eddy current inspection for wear (Appendix A) are discussed separately.

The steam generator has been divided into six areas for purposes of dispositioning tubes for plugging and stabilization. Two areas are within the upper tube sheet: between US+8 and US+4, and between US+4 and US+0, where US+0 is the lower face of the upper tubesheet. Tubes where the lowest defect is above US+8 are repaired by kinetic expansion. Tubing between the tubesheets has been divided into three areas: tubes between the 15th support plate and US+4, tubes between the 15th support plate and LS-4 in the lane/wedge area, and tubes between the 15th support plate and LS-4 outside the lane/wedge area. The last region considered was that within the lower tubesheet. Plugging and stabilization criteria are discussed in detail in Reference 25, and summarized below:

1. <u>Tubes with Defects Between US+4 and US+8"</u>

   Tubes with a defect between US+5 and US+8 may not be effectively repaired by the 22" Kinetic Expansion. A qualified length of 6" expansion is required to insure a leak-tight, load-carrying joint to assure the OTSG integrity is retained under the most adverse conditions during operation. Therefore, those tubes with defects between US+4" and +8" were both kinetically expanded to 22" and plugged. Even if the existing crack would propagate in the future and sever at US+5", testing (Ref. 23) indicates that the expansion joint below the severance would provide enough engagement to maintain the preload in the tube and carry the loads associated with the most severe transient during normal operation. Thus tubes with defects in this area are not expected to wear adjacent tubes due to dynamic instability in high crossflow. Therefore, it was concluded that these tubes need not be stabilized (unless stabilization is required by defects of greater than 3 coils between US+4" and US+5").

2. <u>Tubes with Defects Between US+4 and US+0</u>

   Even with a 22" expansion, these tubes would not have the 3" kinetic expansion joint below the defect to maintain preload and assure that the tube will not slip under the most severe transient during normal operation (i.e., 100°F/hr. cooldown). If the tube ratcheted down during operation, the potential exists for the tube becoming dynamically unstable or buckle. Therefore, after receiving a 22" expansion, a tube with a defect in this area was plugged and stabilized through the 14th tube support plate.

3. <u>Tubes with Defects Between 15th Support Plate to US+0</u>

For conservatism, any eddy current indication identified during the 1982 technical specification record inspection in this area, regardless of type, through-wall measurement or circumferential extent, was treated as a defect. Tubes with defects in this area received a 17" expansion and were stabilized to the 14th tube support plate, unless a lower defect was located in an area requiring a longer stabilizer.

This criterion covers the high cross flow tube span in the top of the steam generator. Even if a tube were postulated to become severed at this elevation, it could not get free and damage adjacent tubes.

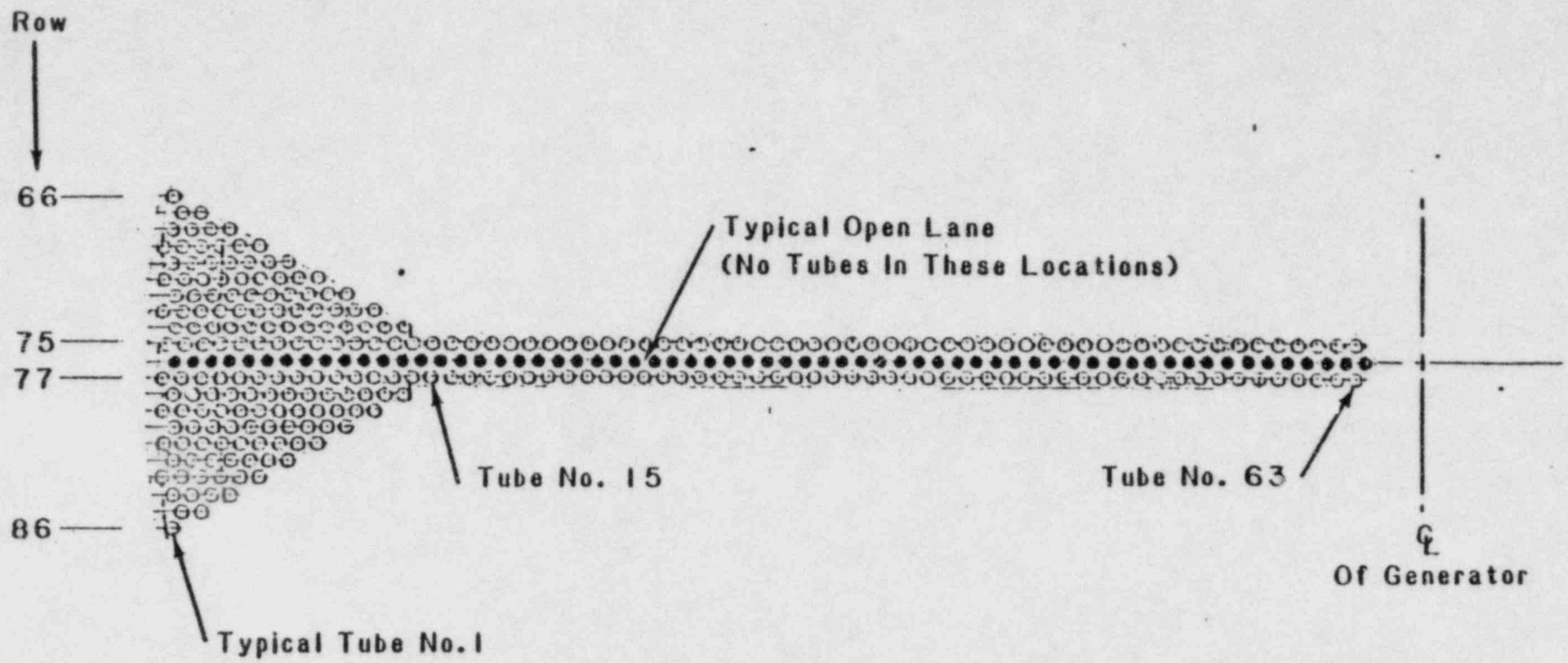
During the post-repair eddy current baseline inspection, several less than 40% through wall indications were identified in this area but not subsequently plugged or stabilized. All of these less than 40% through wall calls were of such low voltage and such uncertainty in phase angle that it could not be concluded with confidence whether they represented intergranular attack or surface anomalies. It was concluded that they are not of a size to warrant plugging. Details of the post-repair eddy current baseline inspection results are in Appendix A.

4. <u>Tubes with Defects from 15th Support Plate to LS-4 in Lane Wedge Area</u>

B&W plants have a history of corrosion and vibration problems in the areas of the untubed inspection lane. As a precautionary measure, an area of potential problems has been defined one row on either side of the lane, widening to a wedge shape as the lane nears the periphery. For tubes in this area, any I.D. eddy current indication, regardless of type, through-wall measurement, or circumferential extent, was treated as a defect. These tubes receivef a 17" expansion, then were plugged and stabilized through the 14th support plate unless other criteria required stabilization through the defect in the lower spans.

5. <u>Tubes with Defects Between the 15th Support Plate and LS-4</u>

In the tube span between the 15th support plate and LS-4 outside the lane/wedge area defects were divided into two groups: 1) ECT indications greater than or equal to 40% through wall with 8x1 indication greater than 2 coils, and 2) ECT indications greater than or equal to 40% through wall with 8x1 indication less than or equal to 2 coils.



LANE/WEDGE AREA OF TUBES TO BE STABILIZED

FIGURE VII-2

After a 17" expansion, tubes with defects greater than or equal to 40% through wall and 8x1 greater than 2 coils were stabilized through the span with the lowest defect for that tube. Tubes with greater than 40% through wall defects and 8x1 indications on 2 coils or fewer were expanded to 17" or 22" as appropriate and plugged with the Westinghouse rolled plug.

This criterion provides a means for determining the tube arc length extent of a defect in order to decide if the tube should be stabilized. The tube would be stabilized at least within the tube span containing the ECT indication if there is any substantial size or arc length involved in the ECT indication. If an ECT indication is seen on less than three coils on the 8x1 ECT probe it means that the arc length of the degraded area of the tube of a maximum of about 0.41 inch long at the inside diameter of the tube. Because of the "thumbnail" shape of the inside diameter cracks found at TMI-1 this means that the average arc length of the largest two-coil ECT crack would be about 0.26 inch. This size crack is acceptable without stabilizing and is not expected to propagate to failure by mechanical means during operation (Ref. 25).

This criteria for stabilizing, based on arc length as measured by the 8x1 probe is not invoked for ECT indications less than 40 percent through wall because such an indication is too small to fail the tube. Even if a tube had a 360° indication, the tube would not fail with less than 40 percent penetration (Ref. 25).

6. Tubes with Defects in the Lower Tubesheet Below LS-4

Tubes with pluggable defects in the lower 20" of the LTS were removed from service using a Westinghouse rolled plug or an explosive plug. A welded plug was used in lieu of mechanical rolled plugs if the defect was in the rolled area.

D. Post Repair Testing

The following post repair tests will be performed to verify plug integrity.

1. 150 psig bubble test
2. 150 psig drip test
3. 1400 psid operational leak

Details of post repair testing can be found in Appendix A. The cold tests described as items 1 and 2 above have been completed. All plugs which were identified as leaking unacceptably were repaired or replaced.

E. Conclusions

The OTSG Tube Plugging Plan has restored the pressure boundary integrity of the steam generators by removing defective tubes from service for those tubes which have defects below the region available for expansion repair.

The plugs used have been previously qualified for use. Tubes have been stabilized which have large defects in areas of high crossflow or areas of historic problems with vibration or corrosion at B&W plants. Thus plugged tubes with the highest potential for tube severence in the future are prevented from wearing adjacent tubes.

VIII. COMPARISON OF TUBE PLUGGING WITH DESIGN BASIS

A. Introduction

This section describes the results of analyses performed to determine if the steam generators could be safely operated with up to 1500 tubes plugged. The first part of this section reviews the operational consideration of operating with tubes removed from service for: reduction in total flow and margin to departure from nucleate boiling effects of asymetric flow distribution, effects on flow coastdown rate, effects on steam generator mass inventory and capability of natural circulation. The second part reviews the effects of removing tubes from service on small and large break loss of coolant accidents as well as all other accidents and transients analyzed in the FSAR. The third part considers the effects of plugging on moisture carryover. These analyses have concluded that the margins of safety as defined in the Technical Specification will not be reduced by operating the TMI-1 steam generators with up to 1500 tubes removed from service.

B. Operational Performance

1. RC Flow Rate and Margin to Minimum DNBR

The calculated RC flow rate for all four RC pumps operating as a function of an equal number of tubes plugged in each steam generator is shown in Figure VIII-1. Generally, a reduction in tubes available for RC flow will cause the tube bundle pressure drop to increase. Since the remaining system pressure losses are about four times greater than the tube bundle pressure losses, only a slight reduction in total RC flow rate will result. The total RC core flow for 1500 plugged tubes will be the same as the symmetric case, i.e. 750 in each steam generator. From the figure, the reduction in total RC flow will be from 109% of design to 108.2%, a change of 0.8%. (Reference 42)

In order to determine the impact on the existing steady state Departure from Nucleate Boiling Ratio (DNBR) resulting from the RCS flow reduction at steady state, a study was performed to determine the minimum RCS flow rate required to maintain the existing DNB ratio for the TMI-1 licensed power level of 2535 MWt. The existing DNB steady state ratio of 2.0123 was determined at a conservative power level of 2568 MWt and an RCS flow rate of 106.5% of design flow.

The methodology for the analysis was to calculate the hot bundle flow by using a CHATA (Reference 36) core model which took heat balance input from the CIPP code (Reference 37). By using the hot bundle flow in the computer code TEMP (Reference 38), the Minimum DNBR (MDNBR) was calculated for the hot sub channel from the BAW-2 correlation (a correlation.

The results indicate that DNBR value of 2.0123 can be maintained with an RCS flow rate of 104% of design and a power of 2535 MWt as compared with the original 106.5% flow and 2568 MWT. The minimum calculated RCS flow rate at TMI-1 has been 109.5% of design flow. The maximum error on this value is 1.5%. This results in a mininum available flow of 108% of design. This will be reduced to 107.2% after the tubes are plugged. This is substantially greater than the design basis flow rate of 106.5% which would be required to maintain the design basis steady state DNBR value of 2.0123 at 2568 MWt. For the TMI-1 power level of 2535 MWT, the 104% design flow requirement to maintain the same DNBR provides for an even greater margin. It can thus be very conservatively concluded that the plant design basis flow rate considerations will be preserved with 1500 tubes plugged.

2. Asymmetric RC Loop Flow Distribution

The final plugging pattern will be about 6% of the tubes in the A Steam Generator and about 2% of the tubes in the B Steam Generator. In order to investigate the asymmetric effect of the RC loop flowrates, an evaluation of an exaggerated plugging pattern of 1500 tubes in one of the TMI-1 steam generators has been performed. The Loop A flowrate will be approximately 2-1/2% smaller than Loop B.

Field data at TMI-1 during the last cycle has shown that the A loop has typically about 3% more flow than the B loop. The result of more plugging in the A Steam Generator will thus be a somewhat more balanced loop flow distribution. The new flow difference is expected to be approximately 0.5%.

3. RC Flow Coastdown Rate

With a significant number of tubes being plugged, the resistance factor for the RC flow passing through the OTSG will be increased. This increased resistance may change the flow distribution if one RC pump is tripped while the other pump in the coolant loop is maintained in operation. The combined core flow during the coastdown may also be different.

Further, the minimum margin to DNBR during a loss of flow event is known to be dependent on pump coastdown rates. To address these issues the following analysis was done.

A computer analysis has been conducted using the B&W code "PUMP" (Reference 39) for the TMI-1 type reactor coolant system's flow coastdown curves with zero and 1500 tubes plugged in the A Steam Generator. The FSAR analyses served as the base case for the four pump coastdown transient. Results of the analyses with 1500 tubes plugged in one steam generator show that the FSAR coastdown rate is still bounding.

Figure VIII-2 summarizes the data obtained from the four pump coastdown transient performed with the TMI-1 version of PUMP code and compares this data with the FSAR analyzed flow coastdown. This comparison shows that the flow even with 1500 plugged tubes starts at a higher level than the flow assumed in the FSAR analysis and coasts down at approximately the same rate since the flow is at all times greater than that assumed in the FSAR the minimum margin to DNB will not be changed.

4. Steam Generator Water Inventory and Operating Level Indication

The water inventory in the steam generator, will increase by a small amount due to the decrease in average quality in the plugged section. RETRAN-02 (Reference 43) and TRANSG (Reference 44), which are both one dimensional transient thermal hydraulic computer programs with slip option, have been used. The inventory increase was calculated to be 5% or less, which is less than 2000 pounds with 1500 tubes plugged.

Total secondary side flow will increase only slightly with decreased steam outlet temperature. This would tend to cause a slight increase in pressure drop. This increase will be offset by the reduction in average quality (increase in density). The net effect should be little or no increase in the startup level.

5. Capability of Natural Circulation

The impact of steam generator tube plugging on the capability of stable transition to natural circulation was examined by using the B&W computer program AUX (Reference 49). Symmetric plugging of 1500 tubes in each side was

FIGURE VIII-1

REDUCTION IN RC FLOW RATE VS. NUMBER OF TUBES PLUGGED PER STEAM GENERATOR

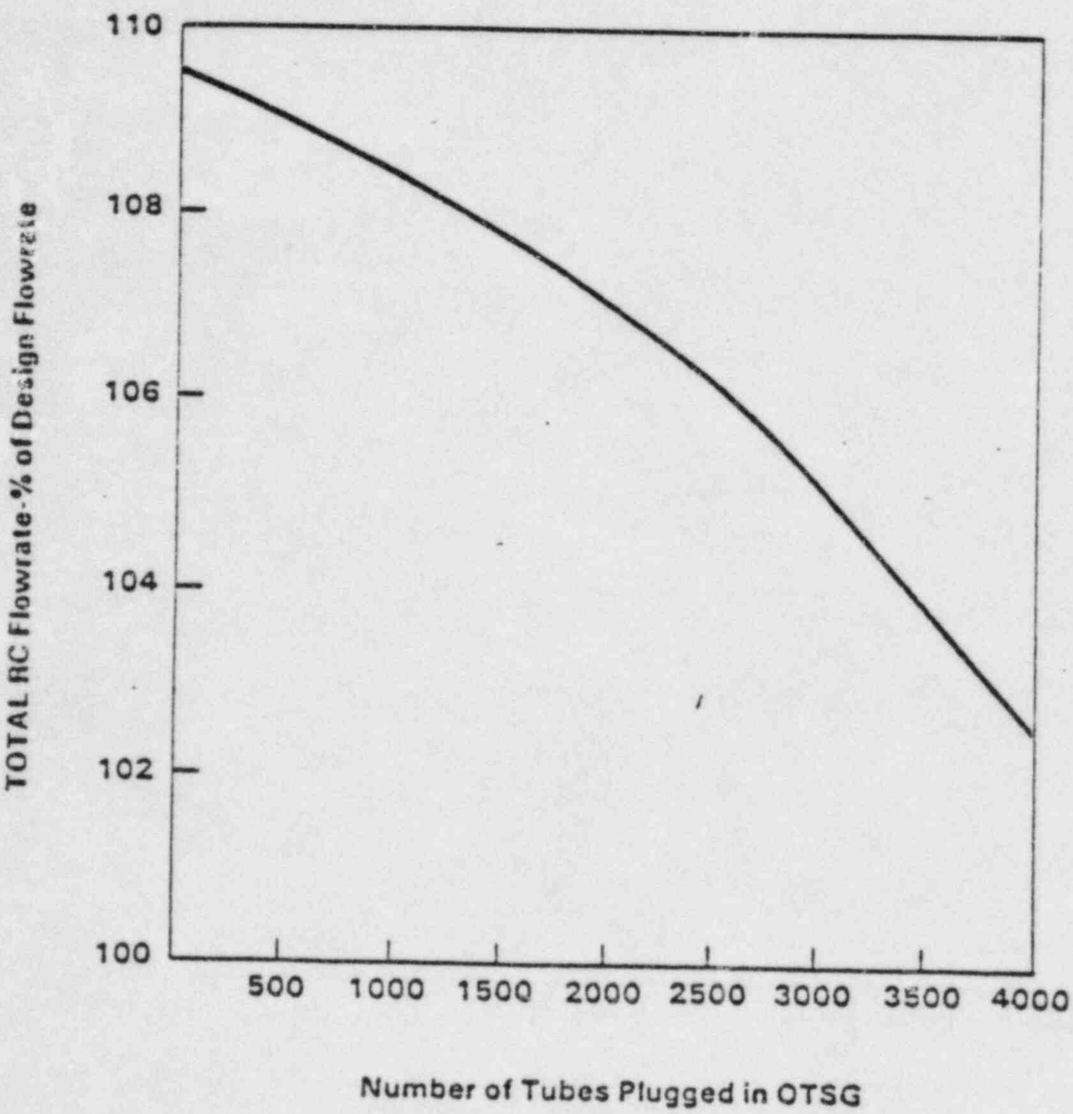


FIGURE VIII-2

COMPARISON OF FLOW COASTDOWN
CURVES - FSAR FOUR PUMP COASTDOWN
VS. FOUR PUMP FLOW COASTDOWN WITH
1500 PLUGGED TUBE

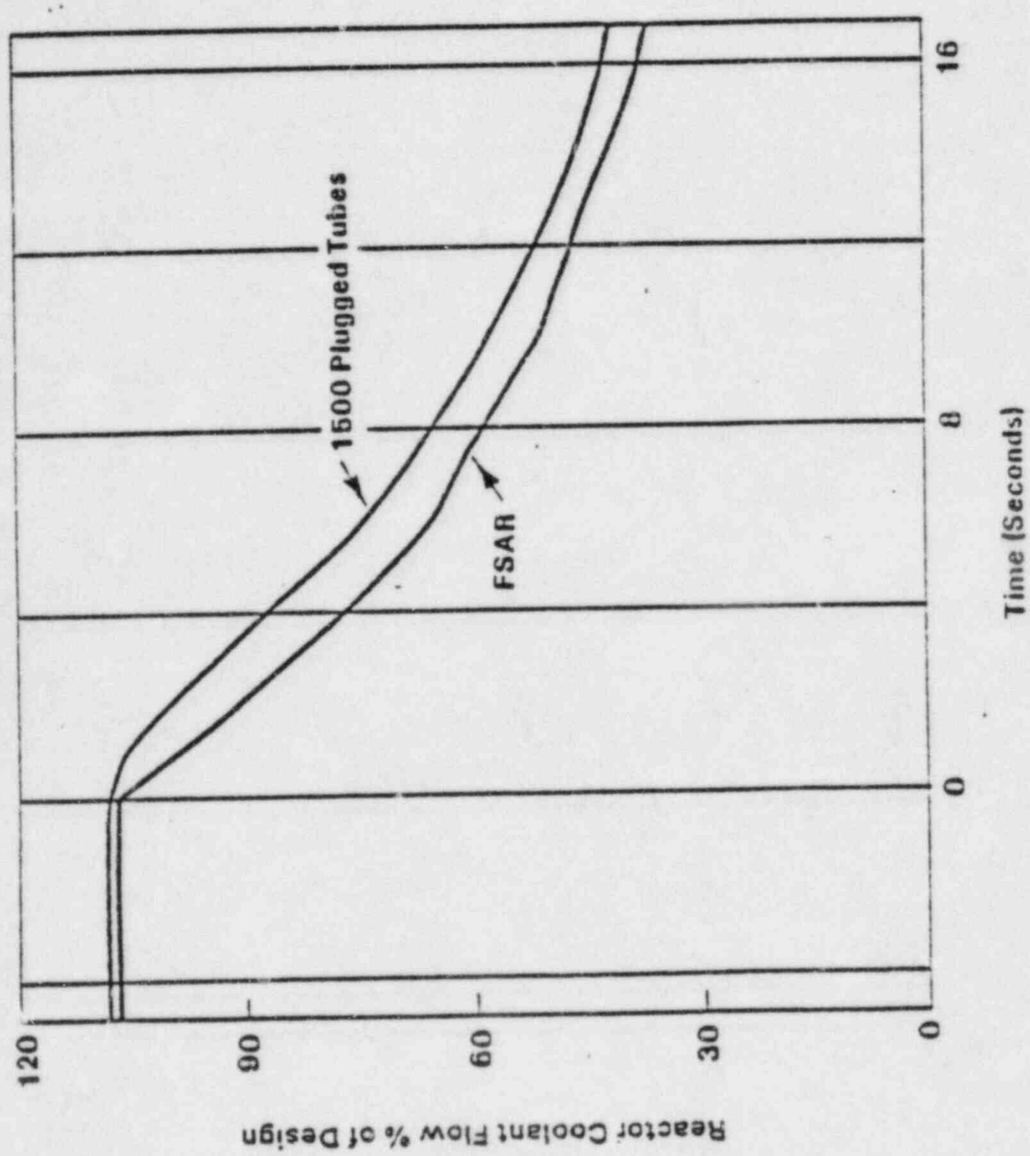


FIGURE VIII- 3

TMI-1 EFFECT OF TUBE PLUGGING ON NATURAL CIRCULATION
TOTAL CORE FLOW VS TIME

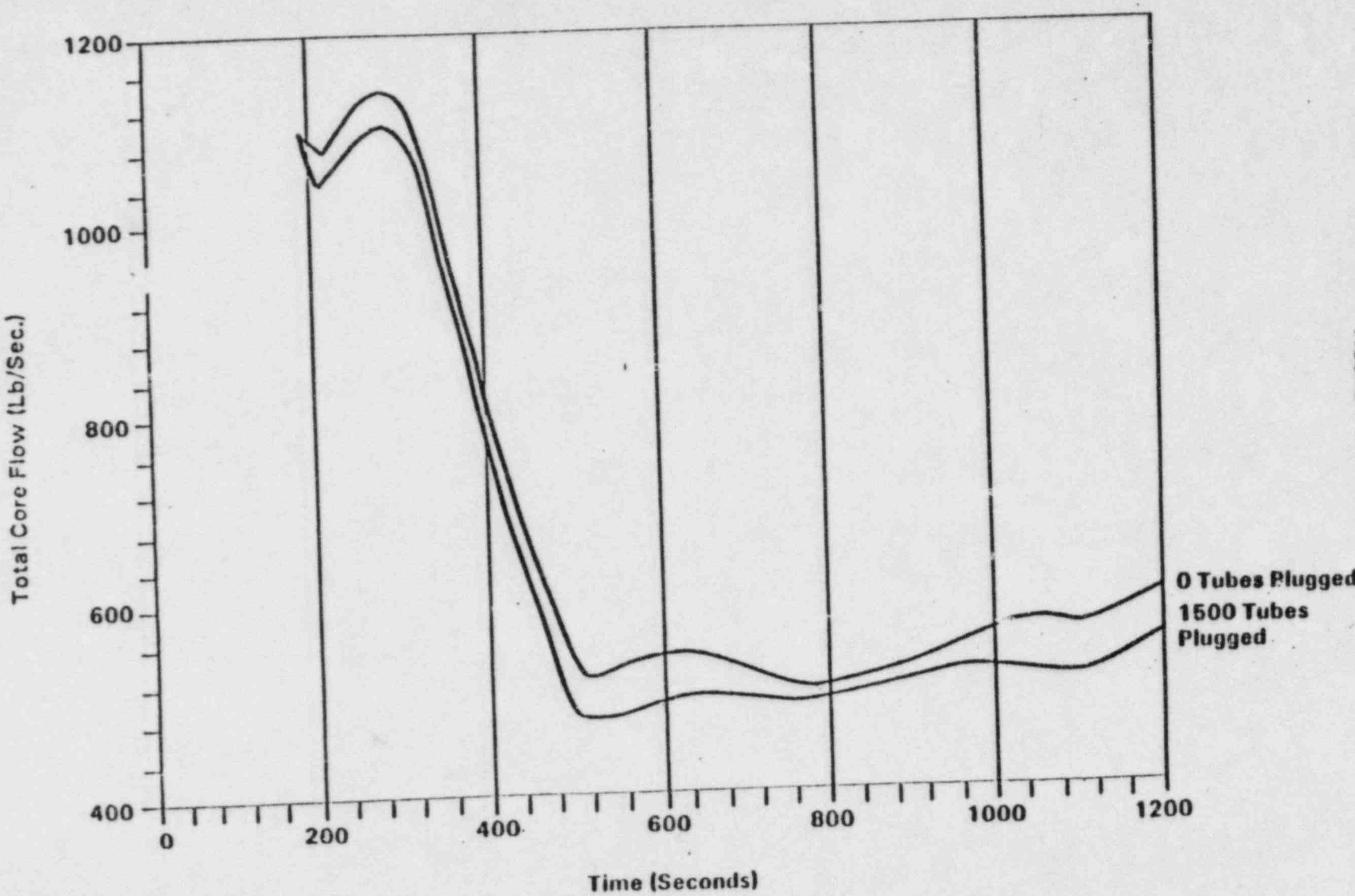
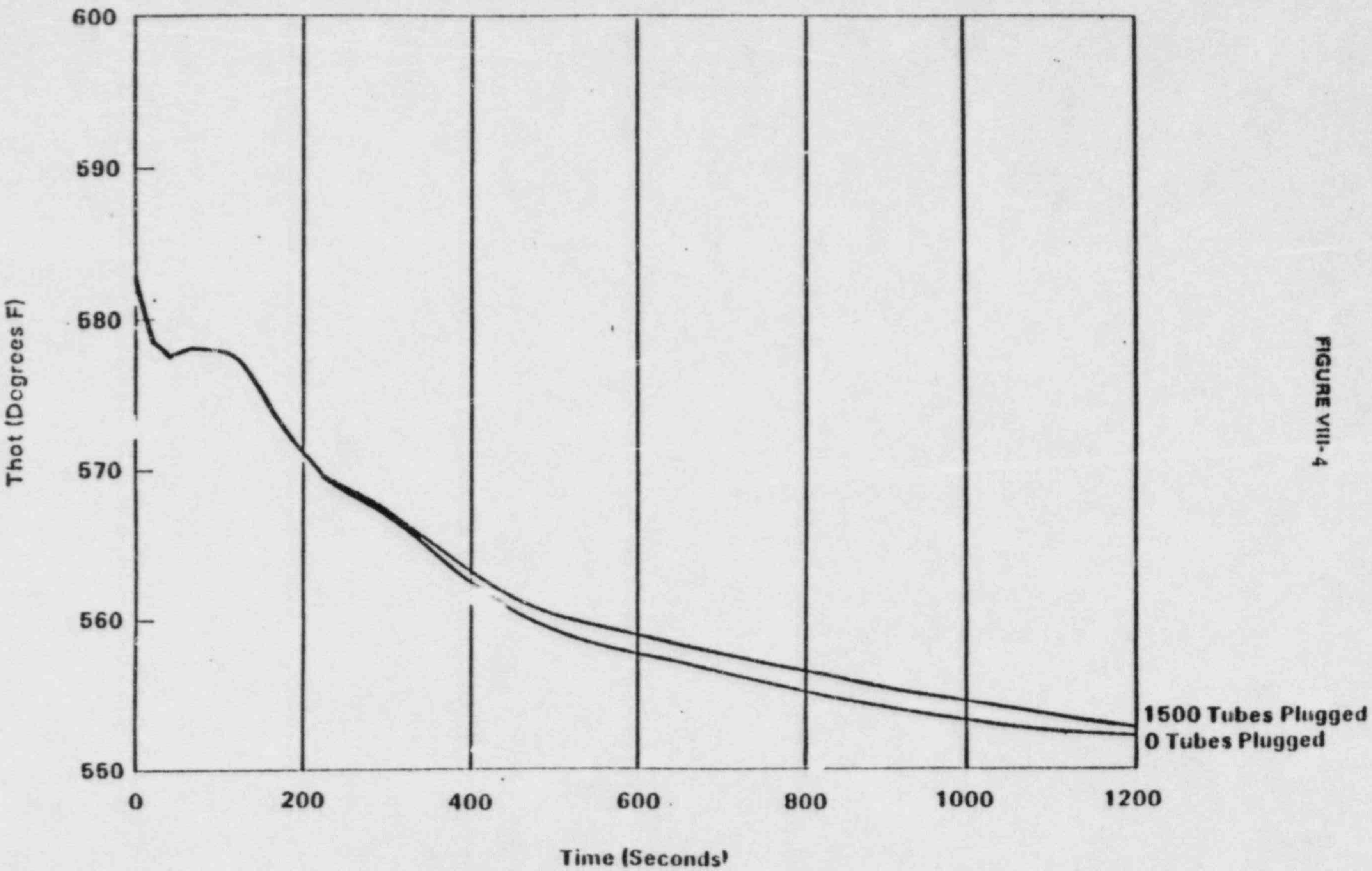


FIGURE VIII-4

TMI-1 EFFECT OF TUBE PLUGGING ON NATURAL CIRCULATION
THOT LOOP 1 VS TIME



assumed to be the bounding case. Figures VIII-3 and VIII-4 compare the analysis results of 1500 tubes plugged to no tubes plugged. At about 500 seconds after the reactor coolant pumps trip, the stable natural circulation flow with 1500 tubes plugged is about 8% less than that with no tubes plugged. At no time is natural circulation lost and the reactor coolant system remains subcooled. The subcooling margin for 1500 tubes plugged is only about 2°F less than the case without plugging (about 90°F). Therefore these analyses have shown that natural circulation is still an effective method for decay heat removal.

C. Accident and Transient Performance

1. LOCA Analyses

The potential effects of SG tube plugging on generic Large Break LOCA (LBLOCA) and Small Break LOCA (SBLOCA) analyses (Reference 40) with 1500 tubes plugged has been examined. With about 6% of the tubes in the A Steam Generator and about 2% tubes in the B Steam Generator being plugged, the generic (2772 MWt) LOCA analyses for B&W 177FA Lowered Loop Plants remain valid for TMI-1, with continued operation at core power levels up to the licensed 2535 MWt at the existing LOCA limits. An overview of this examination is provided below.

a. SBLOCA Concerns

The evaluation models used in the existing SBLOCA analyses (Reference 40) assume equilibrium conditions within the control volumes used to model the SG secondary side. For this reason, the localized cooling effects of EFW spray on particular tubes, and the effects on this cooling if particular tubes are deactivated, cannot be accurately predicted with these models.

In the application of the revised SBLOCA evaluation model (Reference 41), it was assumed that:

1. The percentage reduction in the number of peripheral tubes removed from service will degrade the EFW spray cooling heat removal capability in a 1:1 relationship.

2. The degradation in heat removal capability from EFW spray cooling translates directly to a reduction in depressurization rate by a 1:1 relationship.

In reality, these relationships are expected to be conservative. Since if EFW spray impacts a deactivated tube, it will not be heated and/or flashed immediately but will either:

1. Be redirected onto adjacent active tubes, or;

2. Flow inward into the tube bundle, providing cooling to active interior tubes, or;

3. Fall into the saturated steam or saturated water region, resulting in increased cooling within these regions and/or an increase in the fill rate to the appropriate level setpoint.

A more detailed discussion of EFW spray effectiveness and the TMI-1 response to SBLOCA with plugged tubes is given in Ref. 59.

Therefore the water is available in the steam generator and will result in greater EFW spray cooling and higher depressurization rate than predicted by the analyses.

In this evaluation (Reference 42), two break cases were considered. The first is the worst case with respect to peak clad temperature for a small break LOCA, identified as approximately a 0.07 ft^2 cold leg break. The second, belongs to the category of breaks in which SG heat removal is needed to help depressurize the RCS. The 0.01 ft^2 break was analyzed because this was the largest break size which would result in RCS repressurization.

Plugging 1500 SG tubes was used as a upper bound which represents a deactivation of approximately 5% of TMI-1's total tubes. Also, because substantial tube plugging will be done in the peripheral SG tubes regions, it is estimated that about 18% of TMI-1's total peripheral tubes will be deactivated.

Worst Case 0.07 ft^2 Cold Leg Break with One HPI Train

For this break size, the primary system pressure decreases below 1000 psi (approximately the secondary side pressure) at about 300 seconds. After this time, SG heat removal is no longer possible, and the secondary side becomes a heat source for the primary system. Core uncovery begins at about 1350 seconds and ends at about 1750 seconds. The maximum time that SG (and EFW spray) cooling can be of benefit during the accident is the first 300 seconds. This is very short when compared with the time to begin core uncovery.

The plugging of 1500 SG tubes will result in a reduction of the initial RCS liquid inventory by about 200 ft^3. This results in the core being uncovered about 3 seconds earlier and in approximately a 10F increase in peak cladding temperature (to about 1100°F). This will have minimal impact on the outcome of this accident. It should also be noted that the generic analyses show that, for a 0.07 ft^2 break with 2 HPI trains, the core does not uncover and temperature remains below 700°F.

<u>0.01 ft^2 Cold Leg Break</u>

The 0.01 ft^2 cold leg break case was evaluated using the revised SBLOCA model. All of the original analysis assumptions were preserved, including a 20 minute operator delay in initiating emergency feedwater. Two cases were analyzed considering the effects of tube plugging on the decrease in RCS depressurization rate which could increase the time to initiate ESFAS and the rate of heat transfer in the boiler condenser mode. It was found that:

With a 1600 psig low RCS pressure ESFAS setpoint, the 0.01 ft^2 case will result in ESFAS actuation regardless of the reduced peripheral and internal SG heat removal caused by the plugging of 1500 SG tubes. Before ESFAS actuation, the RCS was subcooled and either forced or natural circulation existed. Consequently, SG heat removal was found to take place throughout the entire SG tube region, not predominantly in the peripheral regions. Therefore, the SG heat removal rate is not reduced by more than 5% during the period prior to ESFAS, and this will delay only slightly the activation of ESFAS.

The 0.01 ft^2 break case will cause the RCS to enter the boiler-condenser (B-C) mode. In this mode, EFW spray cooling of the peripheral tubes is an important factor in the RCS depressurization. Thus, peripheral SG tube plugging could have a more significant effect on this cooling mode. The evaluation showed that, with 18% of all peripheral tubes plugged, sufficient steam generator EFW spray heat removal capability remains so that the rate of RCS depressurization is reduced by only about 12%. Even with this reduction, calculations with all other original analysis assumptions unchanged show a minimum of five feet of coolant remains above the core throughout the event. Since the 0.01 ft^2 break is

approximately the largest break which would result in RCS repressurization, the plugging of 1500 SG tubes is expected to have only minimal effect on SBLOCA transients.

In summary, these small break size LOCA analysis show that for the previously limiting case of 0.07 ft^2 cold leg break with only one HPI train available, peak clad temperature increased by only 10°F to about 1100°F. For the 0.01 ft^2 cold leg break, the slight delay in ESFAS actuation and the reduced area for EFW cooling have an insignificant effect on the outcome of the transient since a minimum of five feet of coolant remains above the core for both the plugged tube and unplugged tube cases. Therefore the generic LOCA analyses remain valid for TMI-1 even with a small reduction in SG heat removal caused by tube plugging.

b. LBLOCA

The important parameters for the LBLOCA which are effected by plugging of tubes are the initial flow and flow coastdown. The effects of the reduction in coolant volume associated with 1500 plugged tubes (200 ft^3) are negligible for this event. The plugging of 1500 SG tubes at TMI-1 will reduce total system flow. However, the reduced flow will still be greater than the flowrate used in the generic LBLOCA analyses. This, coupled with TMI-1's lower core power (2535 MWt vs the generic 2772 MWt) provides margin in initial conditions for TMI-1, relative to the generic analysis. During the early portion of a LBLOCA transient when the reactor coolant pumps are coasting down, the analyzed system flow rate (see VIII.B.1.3) with additional resistance due to plugging will be greater than assumed designed flow rate with the case of no plugging.

The reduction of 200 ft^3 of primary coolant volume will have little impact to the consequence of LBLOCA. Since the OTSG's are unevenly plugged with more tubes plugged in A than B. If a cold leg break occurs in the A side, the reduction of RC fluid is part of that blown out of the break, and there will be no impact to the result at all. However, a break in the B side will result in slightly less total fluid passing through the core during the blowdown period. For about 11,000 ft^3 total fluid loss within approximately 24 seconds, the reduction of 200 ft^3 will correspond to 0.4 second

shorter blowdown time and thus a slightly earlier fuel heatup between blowdown and refill. This difference is minimal and therefore, the resulting peak cladding temperature that occurs during this developed reflood stage should not be changed. Also, vent flow is conservatively neglected during the refill/reflooding phases of LBLOCA analyses for the 177FA Lowered Loop plants. Tube plugging will therefore have no impact on core flooding rates.

2. FSAR Analyses of Other Transients

An assessment of the impact of the plugged steam generator tubes on the ability of the NSSS to safely respond to FSAR transient conditions has been performed. The plant is expected to be operated with up to a total of 1500 SG tubes plugged for both steam generators at the licensed rated power level. Each event in the TMI-1 FSAR will be addressed in light of the expected impact of steam generator tube plugging on assumptions used to produce the current FSAR analysis.

a. Uncompensated Operating Reactivity Changes

This event is core burnup related and is normally compensated for by Integrated Control System action over the life of the fuel cycle. Steam generator plugging will not affect the core kinetics and thus have no impact on the event.

b. Startup Accident/CRA Withdrawal at Power

The CRA Withdrawal from Startup conditions and at power results in primary system overpressurization. The FSAR prediction of RC pressure and peak thermal power is based on the conservative assumption that all heat produced in the core remains in the primary system, i.e., no steam generator heat transfer. The tube plugging will result in a 200 ft^3 volume reduction of the primary coolant (2%). At peak thermal power the reactor coolant pressure increase was 118 psi in the FSAR. With the small volume reduction and consequently slightly higher heatup rate the peak pressure may increase slightly but will remain well below the 2750 psig limit. Therefore, the FSAR analyses remain bounding with respect to the acceptance criteria on thermal power and system pressure.

c. Moderator Dilution Accident

The moderator dilution event is a relatively slow overpressurization transient due to increased reactivity by boron dilution. Change in steam generator plugging will not affect the basic assumptions of this analysis and therefore the FSAR remains bounding.

d. Cold Water Accident (Pump Startup)

The pump startup event is a small overcooling transient due to an increase in flow from an idle loop. The analysis performed for Section 8.B.3 demonstrated that the pump characteristic curves differences are negligible for the unplugged and the 1500 plugged tube cases. The reactivity change will cause a power and RCS pressure increase. The transient will be terminated by either the high reactor pressure trip or the power/flow trip. The FSAR remains bounding.

e. Loss of Coolant Flow

See Section VIII C.1.

f. Stuck/Dropped Rod Event

The FSAR analysis is bounding since SG heat transfer and RCS flow do not effect this event.

g. Loss of Electric Power

The unit will trip on loss of electric power. With the loss of the reactor coolant pumps, natural circulation in the primary loop and heat removal by the emergency feedwater system are required. The impact of tube plugging on the ability of natural circulation is demonstrated in Section B.5.

h. Steam Line Failure

The licensing basis for TMI-1 is the double-ended rupture. This FSAR analysis is based on a very conservative prediction of SG secondary inventory. Operation with plugged tubes results in a secondary inventory greater than operation without plugged tubes but it is not as great as that considered for the FSAR analysis. Secondary inventory is one of the parameters that determine the safety considerations of return to criticality,

and reactor building pressure. The calculated water increase with 1500 plugged tubes is less than 5%, which will result in a maximum steam generator inventory of 42,000 lb. per steam generator in contrast to the FSAR analysis assumption using a steam generator inventory of 55,000 lb per steam generator. It is therefore concluded that the FSAR case remains bounding.

i. Steam Generator Tube Failure

The steam generator tube rupture accident is analyzed assuming a 435 gpm leak from a completely severed OTSG tube. The RCS is depressurized and isolated at 34 minutes, at which time leakage from the RCS is assumed to stop. The reduced RC flow as a result of the plugged tubes is greater than the RCS flow assumed for this cooldown rate (even the 100% design flow is not required to cool the RCS). Similarly, more than enough OTSG heat transfer area is available to cool the RCS.

Offsite dose from the Tube Rupture Event will not be affected by plugging 1500 tubes because neither the time required to isolate the OTSG nor the leak rate from the broken tube is affected by the tube plugging.

j. Fuel Handling Accident

This accident is assumed to occur during outage a refueling outage while the reactor is shut down. Change in steam generator plugging pattern has no impact to the assumptions.

k. Rod Ejection Accident

Fast reactivity excursions are not influenced by SG heat removal. The event is an adiabatic heatup. The FSAR analysis remains bounding.

l. Maximum Hypothetical Accident

The analysis assumed that a given amount of radioactivity has been released following core exposure and studied the effectiveness of the building spray system and Engineering Safeguard systems leakage on to the environment. The steam generators are not related to the scenario and thus have no impact on the conclusion.

m. Waste Gas Tank Rupture

The Waste Gas Tank is located in the Auxiliary Building and the analy is of its rupture is not related to the steam generator's function. The event is thus unaffected.

n. Loss of Main Feedwater/Feedwater Line Break

A loss of feedwater accident is an event resulting in primary system heatup, increased pressurizer level and pressure, and reactor trip either by anticipatory function (loss of main feedwater pumps) or high RCS pressure. The long term cooling relies on emergency feedwater heat removal through the steam generators. With the plugging of 1500 tubes in the steam generators, the intitial heatup rate will be slightly faster. However, the anticipatory trip on high pressure will shut the reactor down and reduce the heat input to its decay heat level regardless of the minor difference in heatup rate. Emergency feedwater has the flow capability of removing decay heat up to about 7 percent power. This is greater than the decay heat at any time after shutdown. In the SBLOCA analysis using the revised LOCA model it was demonstrated that heat transfer rate is not significantly changed with the amount of plugged tubes. Therefore the FSAR analysis of the loss of feedwater accident remains valid.

o. Steam Generator Overfill

Steam generator overfill was analyzed as a part of the TMI-1 Restart Report, (Reference 50). This analysis identified that it takes at least 10 to 17 minutes for auxiliary feedwater to overfill to the top of the steam generator's shroud. Operators are instructed to isolate the feedwater flow path as soon as the OTSG water level reaches 82.5% on the operating range (high level alarm) and to trip or throttle feedwater pumps if the level reaches 90%.

The impact of up to 1500 plugged tubes in one steam generator will be about 5% inventory increase at about the same level indication. This has been shown in Section B.4. This implies a reduction of the overfilling time by about 60 to 100 seconds. The time for the operator to respond to the high level alarm will be shortened. Moreover since there _ still sufficient

time and unambiguous symptoms available for the operators, their prompt response is expected and thus the overfill would be corrected. In addition, a stress analysis has been performed on the consequences of flooding the TMI Unit 1 Main Steam line. The results of deadweight internal pressure and thermal expansion analysis show that the main steam piping can withstand these affects. Therefore operating the steam generators with 1500 plugged tubes will not present a safety concern with respect to steam generator overfill.

D. Moisture Carry-over Considerations

Evaluations were performed to determine whether the plugging pattern would allow moisture to be carried up with the steam, causing potential for erosion of components or steam lines. Calculations of steam conditions at the entrance to the turbine show approximately 33°F of superheat, indicating no moisture problems in the bulk steam. Evaluations were also done, to determine the potential for local effects in areas of high plugging before mixing equalizes temperature. Calculations include multidimensional thermal hydraulic simulation of the OTSG with plugged tubes using the THEDA II Code. Results indicate that moisture carryover from the clustered plugging of tubes should not be a problem. The effects of the aspirator bleed ports and the geometric design of the 15th tube support plate (outermost holes are not broached) work together to substantially reduce moisture carryover. An ISI program will be implemented to further assure the integrity of peripheral tubes and downstream components and piping. Peripheral tubes in areas of high plugging are included in the post-repair eddy current program. A supplemental ISI program of steam system fittings will be implemented. Both programs are described in Appendix A.

E. Conclusions

Evaluation has shown that up to 1500 plugged tubes per steam generator have no adverse effects on performance of the steam generators. The reductions in flow and heat transfer are not large enough to affect the licensing basis analyses for transients or accidents. In addition, moisture carryover is not expected to cause erosion problems, but monitoring of the steam system fittings will identify erosion should it occur.

IX. UNREPAIRED PORTION OF TUBES

Reference 2 and Sections IV through VI of this report discusses tubes in the area of the kinetic expansion, plugged tubes and how they meet the design basis. This section discusses how tubes in the remainder of the steam generator meet the design basis. The rationale for resuming operation with the existing steam generator tubing is based on these facts:

1. Corrosion tests indicate that the cracking mechanism has been arrested and will not reactivate in low sulfur primary coolant water chemistry. If the cracking does reactivate due to an unknown mechanism at operating temperatures or during heatup and cooldown cycles, it is anticipated that the precritical testing sequence would allow sufficient time for defects to propagate through wall to a size that would allow leakage to be detected.

2. Analyses have demonstrated that cracks below a minimum range of length and through wall thickness will not propagate to failure by combinations of flow induced vibration, thermal cycles, and mechanical loading. Analyses have also calculated a minimum size below which a crack will not become unstable due to plastic tearing or ligament necking during a MSLB. The range of crack sizes above this was detectable by the ECT inspection program that was used to inspect the steam generators, and were removed or plugged.

3. Any through wall defects that are large enough to propagate unstably and are not picked up during the 100% ECT inspection because of equipment or analyst error will be detected by leakage monitoring programs during the test program.

A. New Damage Not Occurring

The following paragraphs address the subject of new damage not occurring in the steam generators. Short term corrosion testing program has provided evidence that the crack mechanism is arrested and the long term corrosion tests will act as an anticipatory program for crack initiation. An eddy current flaw growth program has shown that cracks are not initiating or propagating. Defect indications which are less than 40% through wall and less than 90° in circumferential extent will be left in service and monitored for crack propagation. The precritical testing program will detect reinitiation of a rapid attack through leakage monitoring. A slower mechanism will be detected at the scheduled eddy current examinations or by the leakage monitoring program.

The corrosion testing program results are described in Section III. Tests on actual and archive Steam Generator tubing to date have established:

(a) Cracking will not occur unless an active reduced species of sulfur is present and cracks in SG tubing will not propagate in the present chemical environment;

(b) Sulfur induced cracking requires an oxidizing potential which does not exist under normal hot operating conditions;

(c) Lithium hydroxide is an effective inhibitor of the cracking mechanism.

Tubing which has undergone the repair and chemical cleaning process has also been tested. Accelerated tests performed on this tubing under severe chemical environments has not produced any cracking. To provide assurance that the mechanism has no long term time dependency, a long term corrosion test program has been initiated to provide an anticipatory assessment of tube performance under actual steam generator operating conditions. This program will lead plant operation and will run for approximately one year.

Since identification of the steam generator problem, cracks in the generators have been monitored for growth. Eddy current testing of about 100 tubes in each steam generator was conducted on a repetitive basis to attempt to ascertain if the intergranular attack mechanism was continuing to damage the OTSG tubing during continued dry primary side lay up conditions. The sample selected for this monitoring assumed half tube sheet symmetry and included tubes with no defects, tubes with a variety of defect indications and tubes in periphery and interior areas of the bundle previously identified as high and low defect rate areas, respectively. The method used involved a relative comparison of the low gain .510 standard differential probe eddy current responses from seven repetitive examinations of the same tube population over a period of time extending from December 1981 through July 1982. The eddy current data was evaluated and compared with previous data for each tube to determine if reported variances from test to test were related to variability in the physical repeatability of analysis of threshold-level defects or to the appearance of fresh defects grown in the interim period between tests. In July 1982, a "new baseline" condition was established with both the .510" std. gain technique and the .540 high gain technique performed consecutively (within 3 days of each other).

The consistent pattern of the test comparisons indicated that significant growth of new intergranular cracks was not detected. Some variability in repeatability of recorded results was observed, however careful review and comparison with previous data established these as expected variances due to such things as "probe motion" noise levels, and previous indications inadvertently not recorded.

The comparison of the July 1982 .540" high gain technique data to the July 1982 510" standard gain technique data run 3 days apart showed a 94% (188 of 201 tubes) agreement with a "no-growth" result. Where 6% (13 of 201 tubes) of the tubes had recorded greater defect indications on the .540" high gain technique, these are established as a product of the higher sensitivity of the .540 technique. This result is consistent with other comparisons of these two techniques. As further confirmation, in August 1982 about 29 tubes were selected from OTSG-1B at-large, where reinspection with .540 high gain techniques had revealed defect indications in addition to those previously identified by the .510" standard gain technique. These 29 tubes were rerun with the .510 standard gain technique and in all cases, a comparison of the two .510 data sets revealed that the tube's condition was unchanged.

It is also noted that these findings are not altered by the results of the 100% inspection of both OTSG's by the .540" high gain technique (when compared to .510" data from about 6 months earlier). No significant patterns of crack growth were apparent in this bulk comparison of data.

Within the limits of eddy current test sensitivity and repeatability, no new cracks were formed or developing in the OTSG tubing during the period from December 1981 to August 1982.

Tubes with ECT indications below US+8" of I.D. 20-40% through wall and verified by the 8x1 probe to be actual defects are considered degraded tubes. Depending on their circumferential extent, the tubes will be left in service and monitored on an extended ISI program. The extended ISI program will include 100% reinspection of the 40% and less through wall indications as a separate subset for three continuous refueling outages. If these eddy current examinations show no substantial growth in the cracks, they will be left in service. Tubes showing signs of crack propagation will be taken out of service based on normal and accepted criteria. Lack of defect propagation will give additional assurance that the mechanism is arrested in the long term.

The degraded tubes in this group were examined in May 1983 as part of the post-expansion special baseline ECT inspection. With one exception, the indications were unchanged from the

August 1982 record inspection. On one tube, the phase angle for an OD indication located near a tube support plate shifted such that the previous 35% through wall indication was evaluated as 60%. The 8x1 data did not change (1 coil, 1/2 volt). The phase change was apparently due to interference from the tube support plate. This indication, like the other inspected, was evaluated as unchanged. However, due to the uncertainty in through wall extent, the tube was plugged.

As discussed in Appendix A, the post-repair eddy current inspection also identified several small indications not noted as a result of the 1982 record inspection. The 1982, 540 probe record inspection tapes were re-examined, and it was determine that most of the 1983 indications are within the 1982 tape noise level, but can be considered identifiable given the precise location information from the 1983 results. These indications are considered consistent with the 1982 record inspection, supporting the conclusion that corrosion has not reinitiated since August 1982.

Degraded tubes identified in the 1983 post expansion ECT examination have been added to those previously identified for special monitoring at the 90-day and subsequent inspections. Changes in these indications will be evaluated to determine if growth of the existing ECT indications is occurring.

More rapid propagation if it occurs, will be evident during the precritical and power ascension test program described in Appendix A. This program will subject the tubes to normal heat-up and cooldown stresses and to one accelerated cooldown stress test. These transients are expected to cause defects to open so that any circumferential cracks which are of a size that would propagate unstably will be readily detectable due to leakage. Leakage will be monitored both during cooldown and during steady state operations. Between each of these cooldown tests the plant will be maintained in a hot, pressurized condition to allow time to determine if cracks have propagated to a through wall extent and to allow sufficient time to detect any changes in leakage. Cracks which opened during the cooldown transients are expected to continue to leak during steady state operations since plastic deformation at the crack tips and erosion of the crack surfaces result in a permanent crack opening displacement even when loads are reduced. The test program will be completed by a cooldown from hot conditions to cold shutdown temperatures as a final indication of tube integrity. Leakage monitoring will be continuous during this test.

Leakage monitoring programs during the hot test period are adequate to detect 100% through wall cracks whi[illegible] mechanically fail during a transient or accide[illegible]dition. Adequate time for propagation due to intergran[illegible] stress assisted cracking will be allowed during the test program. Since

previous experience indicated that the corrosion mechanism propagates rapidly, a lack of any significant leakage would provide added assurance that cracks are not propagating. Corrosion testing indicated that the mechanism will not be active in high temperature environments such as those that will exist during the test period. Eddy current examination is not planned to be conducted at this phase of the test program since leakage detection has higher integral sensitivity and reliability. In addition, opening the steam generator for inspection would expose the tubing to an unnecessary oxidizing environment. Good engineering practice dictates that exposure to air should be minimized.

Both long and short term corrosion tests provide evidence that the crack mechanism is arrested. The flaw growth program has shown that cracks are not propagating or initiating within the steam generators. The precritical and power escalation test program will give assurance in the short term, and in the long term, eddy current testing, steam generator leakage monitoring, and the long term corrosion test program will give tube integrity data and assurance that cracks are not initiating or propagating during operation. In addition the monitoring of degraded tubes will give additional assurance that the cracking mechanism is arrested.

B. Defect Detectability

An eddy current inspection was conducted of 100% of the in-service tubes in both steam generators for the full length below the top ten inches of the upper tube sheet. The system that was used for this inspection was a .540 inch diameter standard differential probe with a effective gain of approximately 60. Any high noise or otherwise difficult to interpret indications were resolved in conjunction with data from an eight coil absolute probe. The selection of this system is documented in detail in Reference 20. The following summarizes the qualification process which resulted in determining that this system demonstrated adequate sensitivity to detect defects that should be removed from service. This section discusses laboratory calibrations, comparison of field data to metallurgical inspections, measurement of laboratory grown cracks and comparison of differential probe data to absolute probe data.

The eddy current probe systems were tested against electro-discharge machined notch defects at the EPRI non-destructive examination research center in Charlotte, NC. Circumferential machined notches of .187, .100, and .060 inches were machined on the inside diameter of TMI archive steam generator tubing. Each length of notch was machined to through wall depths of 20%, 40%, 60% and 80%. Minimum levels of detectability were determined by comparing defect signal to a field noise level of .3 volts.

The results of these calibrations for a .540 inch diameter differential probe with a gain of 60 at a frequency of 400 HZ are shown in Figure IX-1. Cracks with geometries that fall to the right and above the curve are detectable, those to the left and below are undetectable. The perfectly horizontal geometry of the machined notch is not totally representative of the cracks in the steam generator, but it provides the least detectable geometry for differential eddy current probes. This geometry, therefore, should provide a conservative estimate of defect detectability. Details of this qualification program are contained in Reference 20.

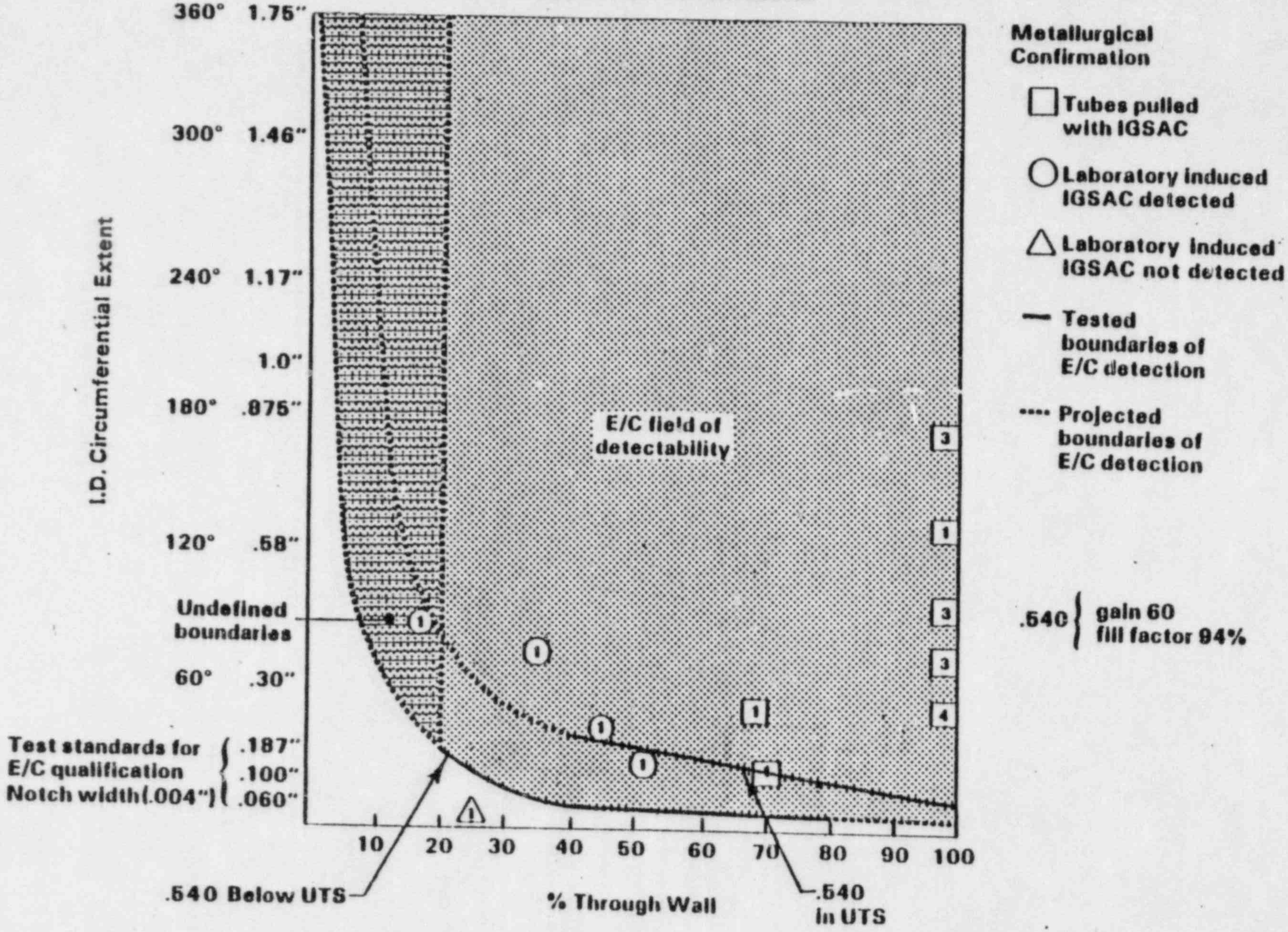
On three separate occasions tubes were removed from both steam generators for metallurgical examination. Details of these examinations are contained in References 3 and 4. One of the purposes of these examinations was to correlate the ECT signals with actual defect geometry. Eddy current reported thru-wall penetrations ranging from 40 to 95%; 39 of 42 cracks investigated in the laboratory had 100% wall penetration, and the three cracks were observed to penetrate 66, 70 and 70% through wall. One possible explanation for the thru-wall discrepancy is that the cracks may not be open in-situ. Although the Intergranular attack penetrates the entire wall, sufficient continuity exists across the grain boundaries to give a less than thru-wall eddy current signal. There were no cases below the roll transition area in which a defect had not been detected by ECT. Details on metallurgical correlations are included in Reference 20.

The particular geometry of these defects were tight circumferential cracks that in most cases, were undetectable by visual examination under microscope or even by high resolution radiograph. The primary means of detecting these cracks is by tube axial sectioning and reverse bending on a 1/4 inch mandrel to open up the cracks. Tubes were examined by this method not only in areas where defects had been detected by ECT but also in good areas of defective tubes and in good areas of tubes taken from low defect areas of the steam generators. In all, 24.6 feet of tubing was examined by this method and no defects were detected except where ECT inspection had indicated a defect. These results increase the confidence level that the sensitivity of the ECT inspection method is sufficient to detect all defects in the steam generator tubing.

To compare the absolute to the .540 high gain standard differential (S.D.), the sample of 3232 tubes previously tested by Absolute ECT (4x1) was retested using the .540 high gain S.D. technique. The sample was predominantly from the high and low reject areas of OTSG "A". The first comparison using the normal S.D. .540 technique indicated a correlation of 99.5%. The quantity of tubes that did not correlate was 16 low level indications. With absolute data, it was determined that these

FIGURE IX-1

METALLURGICAL CONFIRMATION OF ECT SENSITIVITY FOR IGSAC



indications were all one coil, suggesting that the circumferential extent was relatively small. In reviewing the .540 scans, it also appeared that the 16 indications not detected were consistently in the field of the high noise level. To better detect these 16 indications, an I.D. frequency mixing (to remove tube noise/chatter) was added to the S.D. .540 technique. With the added I.D. mixing, S.D. .540 capabilities were enhanced to 100% correlation with the absolute technique as the remaining 16 indications were detected.

This comparison establishes that the normal S.D. .540 technique is as sensitive a method for flaw detection as the absolute.

B & W Alliance Research Center conducted a program to artificially induce IGSAC in archive Inconel tubing. Following exposure to thiosulfate-bearing solutions, the tube specimens were eddy current tested. Scanning Electron Microscopy clearly showed the intergranular nature of the cracking and confirmed that the laboratory induced cracks reproduced the type of cracking and crack shape found in the service failures. For cracks investigated by successive grinding and polishing, measured axial extent ranged from .006 - .017 inches. This is somewhat larger than that of the EDM notches used during the previous 0.540" probe qualifications tests. This value is also larger than the .002" minimum seen during failure analysis on actual tubing. However, the measurements on service tubes were usually estimates made on SEM photos rather than metallographic sections, and would be expected to be lower. The crack axial extent in service and laboratory induced cracking can thus be concluded to be comparable.

Correlation of eddy current results with metallographic observations was performed on samples with the following results. A summary is shown in Table IX-1.

1. The threshold of detectability appears to be comparable to that determined by the original qualification testing. A crack, .040" x 40%, was below the level previously found detectable and was in fact not detected. Cracks of .315" x 38% and 0.140" x 54% were detectable by 0.540" probe. This is illustrated further by plotting the points on Figure IX-1.

2. Using the GPUN ECT 2-step screening technique, 8 samples were tested. Four samples were dispositioned as acceptable and four samples were dispositioned as having unacceptable defects. When confirmed by metallography there was 100% correlation.

From these tests it can be concluded that the detectability of laboratory induced cracks confirms the qualification of the .540 differential probe using actual steam generator tubing as well as EDM notches. Similar qualification programs were conducted to determine sensitivity of the 8x1 absolute probe, and to correlate sensitivities of both probes in the high noise area of the tubesheet.

The ECT system used during the steam generator inspection has the sensitivity to detect crack of the sizes indicated in Figure IX-1. All defects above that size have been identified except for a small number that may have been missed due to random equipment or interpretation errors.

C. Undetected Defects

Some number of undetected defects or other tube surface anomalies may remain in service after the repair is completed. These defects fall into the following categories:

1) Local Intergranular Attack

2) Below the detectable limits of ECT

3) Detectable by ECT but missed through random error

Specimens of actual OTSG tubing have exhibited areas of general surface IGA one to two grains deep. This local IGA is similar to that seen in other Inconel 600 tubes and is generally agreed to be the result of the tube manufacturing process. A few isolated instances of IGA from 6 to 10 grains deep have been found; they are associated closely with visible multiple cracking.

One use of the long term "lead" corrosion testing program described in Section III will be to show that these phenomena are not contributors to tube failure. Specimens selected for this test program will contain general surface IGA as well as crack indications. IGA islands cannot be specifically included as test specimens because its occurrence is random, and it cannot be detected other than by destructive examination. However, by bounding this condition with specimens containing surface IGA and actual cracks, the influence of this condition can be assessed especially on consideration of the fact that metallography has shown that the most extensive IGA is in the vicinity of major cracks. The development of IGA and/or cracks will also be assessed during the test program as specimens will be periodically removed from the test solutions and metallographically evaluated. Both the metallurgical examination program and the long term corrosion testing program provide assurance that the steam generators can be operated safely with local IGA on the tubing.

TABLE IX-1

LABORATORY INDUCED CRACKS E/C CORRELATION

SAMPLE ID	PHYSICAL APPEARANCE	EDDY CURRENT EXAM .510 % T.W.	EDDY CURRENT EXAM .540 % T.W.	EDDY CURRENT EXAM 4x1 # COILS	GPUN 1 DISP.	METALLOGRAPHIC CORRELATION CIRC. LENGTH	METALLOGRAPHIC CORRELATION THRU WALL %	METALLOGRAPHIC CORRELATION MIN. AXIAL EXTENT
A - 1.75	DISTORTED[5]	20 - OD[3]	NE[2]	1 - ID	R	0.2"	50%	.014"
A - 2.32	DISTORTED[5]	35 - OD[3]	NE[2]	1 - ID	R	0.17"	63%	.017"
B - 3.32	DISTORTED[5]	20 - OD	<20 - OD	1 - ID	A	0.4"-0.5"	18%	.006"
C - .76	ACCEPTABLE	20 - ID	<20 - ID	NDD	A	SURFACE ANOMALITY		
D - 1.9	ACCEPTABLE	NDD	35 - ID	NDD	A	NO VISIBLE DEFECT		
E - 4.0	ACCEPTABLE	NDD	65 - ID	1 - ID	R	.315"M	38%	.0065
E - 4.3	ACCEPTABLE	NDD	NDD	NDD	A	.030	25%	
F - 4.8	ACCEPTABLE	85 - ID	55 - ID	1 - ID	R	.14"	54%	.012

1. R = REJECT
   A = ACCEPT
2. NE = NOT EXAMINED (TUBE ID REDUCTION DID NOT ALLOW PASSAGE OF 0.540 PROBE)
3. HIGH GAIN PARAMETER SIMULATED 0.540 SENSITIVITY
4. M = MULTIPLE
5. It is believed the physical OD distortion on the tube has produced the OD differential eddy current response.

In addition to surface IGA, the existence of small cracks below the threshold of eddy current detectability has been considered. Corrosion tests have shown that crack propagation by chemical means is unlikely. Stress analyses were conducted to determine whether small cracks could propagate under conditions of mechanical loading during normal operating, transient, or accident conditions. The evaluation performed had determined the maximum flaw size which will remain stable under normal operating conditions and transient loading. The acceptability of small cracks in service is based on demonstration that eddy current examinations have identified existing cracks of this maximum flaw, and that the small cracks will not propagate rapidly to this size during operation.

The tube loads are derived in part from a generic B&W document (Ref. 52), in part from measurements of the TMI-2 OTSG tubes (Ref. 51) and in part from GPUN calculations (Ref. 61). Recourse is made to field measurements because the steam generator performed better than design assumptions predicted. Twenty degrees more superheat is measured than predicted. The GPUN calculations were performed to provide additional information on how TMI-1 tubes are loaded compared to generic calculations, and how calculated loading varies with changes in initial assumptions. These calculations have provided a range of potential loadings for normal and transient conditions.

The axial load on the tube during anticipated transients, such as heat-ups, power changes, and reactor trips, and steady-state operation are due to:

a. Differences in tube average temperature and the average temperature of the steam generator vessel wall.

b. By virtue of the end fixity of the tube, a longitudinal pressure stress evolves through Poisson's effect. Pressure effects on the shell and tubesheet also contribute to tube axial load.

c. A residual tube axial load component, called tube preload, exists from fabrication.

d. Tubesheet flexibility mitigates axial load, to a greater extent near the OTSG vertical center-line than near the periphery.

Superimposed on the steady axial load is a high cycle, flow induced vibration (FIV) bending load. The frequency and displacement magnitude of FIV was measured at TMI-2 (Ref. 51).

Potential for crack propagation was evaluated in two ways, a fatigue fracture mechanics calculation incorporating FIV and normal operating transients, and solid mechanics calculations of one time transient and accident loads. These calculations were

OTSG Tube Critical Crack Sizes

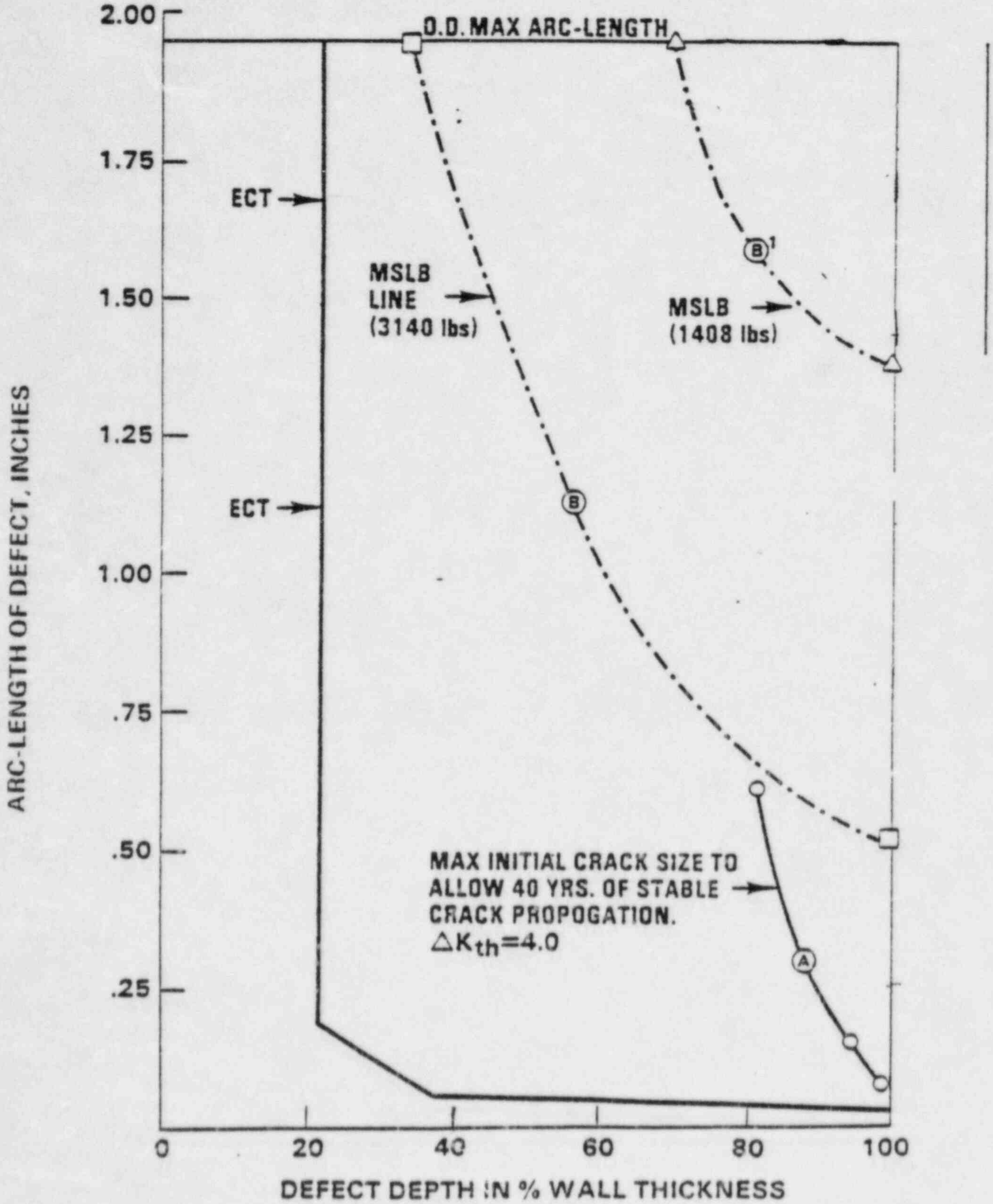


FIGURE IX-2

used to generate curves showing crack depth vs. circumferential extent for the maximum stable crack configurations. The results are shown in Figure IX-2.

D. OTSG Tube Failure Analysis for Unplugged Tubes

Curve A in Figure IX-2 represents the maximum crack size found to be stable with respect to fatigue flaw growth over a 40 year lifetime. The fracture mechanics model uses a preexisting crack and evaluates its propagation under high cycle and low cycle fatigue.

During steady state operation the steam generator could have an axial tension of up to 500 lb. acting on the tubes. In the analysis, the load cycle imposed on the tubes included mechanical and thermal factors. Low cycle, high amplitude loads were combined with high cycle flow induced vibration (F.I.V) loading. A graphical representation of the load cycle is shown in Figure IX-3. The analytical model, which used EPRI fracture mechanics code BIGIF, cycled the high cycle FIV load about 500 lbs. axial tension, the steady-state value calculated from TMI-2 test data. The F.I.V. deflection selected corresponds to the largest peak deflection seen at a TMI-2 sensor during a steady state condition. This is 3 mils, peak half-amplitude displacement. The sensor was located at a "lane" tube which experiences higher crossflow than the average tube. The vibrational load amplitude was selected for conservatism to be the maximum tube displacement seen under steady-state loading.

Combined with high cycle loading was the maximum tension excursion represented by the 100°F/hr. cooldown, as calculated by B&W for the design basis steam generator, which imposes an axial load of 1107 lbs. This peripheral tube axial tensile loading is approximately equal to the maximum load calculated by GPUN for any individual TMI-1 tube during a normal cooldown with a limiting tube-to-shell delta T of 70°F. The FIV and one cooldown comprise a load block as shown in Figure IX-3, with six cycle times per year.

Empirically derived values were used to represent FIV tube loading. The value of R (K minimum/K maximum) thus is approximately equivalent to actual conditions.

The fatigue calculation considered the fact that there is a point at which small indwelling cracks have no effect on fatigue resistance (the endurance limit). This value of the stress intensity, below which cracks do not propagate, is the stress intensity threshold (delta K_{TH}).

A modified Paris equation was incorporated in "BIGIF" with the feature that if the stress intensity range did not exceed threshold, no growth would occur.

The TMI-1 calculation was performed using delta K_{TH}=4.0 KSI (in) 1/2. This value is based on the empirical data for Inconcel 600 shown in Figure IX-4. The intercept of the abscissa is the threshold for propagation. The relationship has been determined for threshold stress intensity and R values so that data taken at different R values has been used to calculate the appropriate threshold for TMI-1 conditions. Delta K_{TH} = 4.0 KSI (in) 1/2 is judged a conservative value.

The evaluation has shown that the high cycle flow induced vibration does not contribute to propagation for ID circumferential cracks. Low cycle loading from the startup and cooldown is the significant contributor to stable crack growth. Curve A in Figure IX-2 represents the maximum crack size which can withstand 40 years of heatup and cooldown cycles without reaching a size which will propagate rapidly to a through wall defect based on the conservative analytical assumptions made. Since this curve is to the right and above the eddy current detectability curve, cracks of this size will not exist in the free span area of the repaired steam generator.

Solid mechanics models have been used to evaluate the ability of cracked tubing to withstand one time transient loads. (Ref. 17 and 61) The maximum accident axial loading on the tubes is during a main steam line break, and is defined as 3140 lbs for peripheral tubes and 1408 lbs for core tubes in generic licensing documents. GPUN's TMI-1 specific analyses (Ref. 61.) indicate these values are conservatively high, and that actual MSLB loading would be 2500 lbs for a peripheral tube and 1000 lbs for a core tube. These axial loads include preload, pressure effects and tube-to-shell temperature differentials.

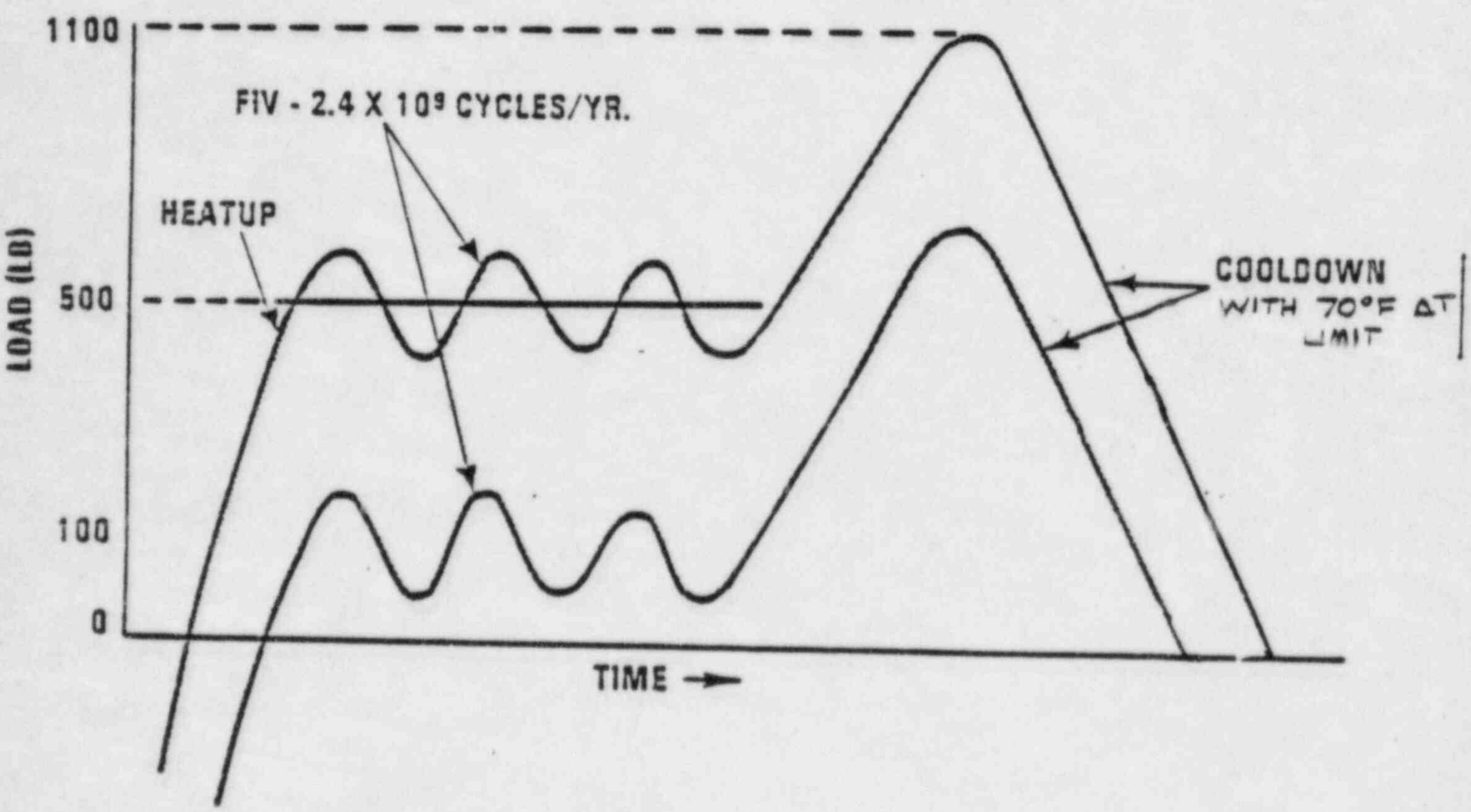
Figure IX-2 shows curves of the derived critical crack sizes in through wall and circumferential extent for the various loadings. In the analysis, the fact that a flawed tube will move laterally under the axial load is included so that the centroid of the damaged cross section approaches the line of action of the load through the intact tube centerline. With this model, the induced bending moment at the flaw is reduced. Assumptions on the tube stiffness remaining and the manner in which strain is absorbed in the area of the crack have been selected to make the results conservative.

Figure IX-2 shows that the maximum crack sizes for failure under transient and accident loading is to the right and above ECT sensitivity. Thus the probability is very small that cracks of this size will remain in service after the completion of repairs.

The laboratory calibration results and the correlation of the differential production probe to the absolute probe results provide confidence that all defects above the detectable size

FIGURE IX-3

OTSG Loading Cycle for Tube Mechanical Evaluation



- FIV ALTERNATING LOAD, REGION I ~ ± 550 PSI, .004" MAX. DISP.
- HEATUP/COOLDOWN, 6 CYCLES/YR.
- 40 YEAR LIFE
- MAXIMUM AMPLITUDES

FIGURE IX-4

Fatique - Crack Propagation Behavior of Inconel 600
da/dn vs $\triangle$K for INCO 600

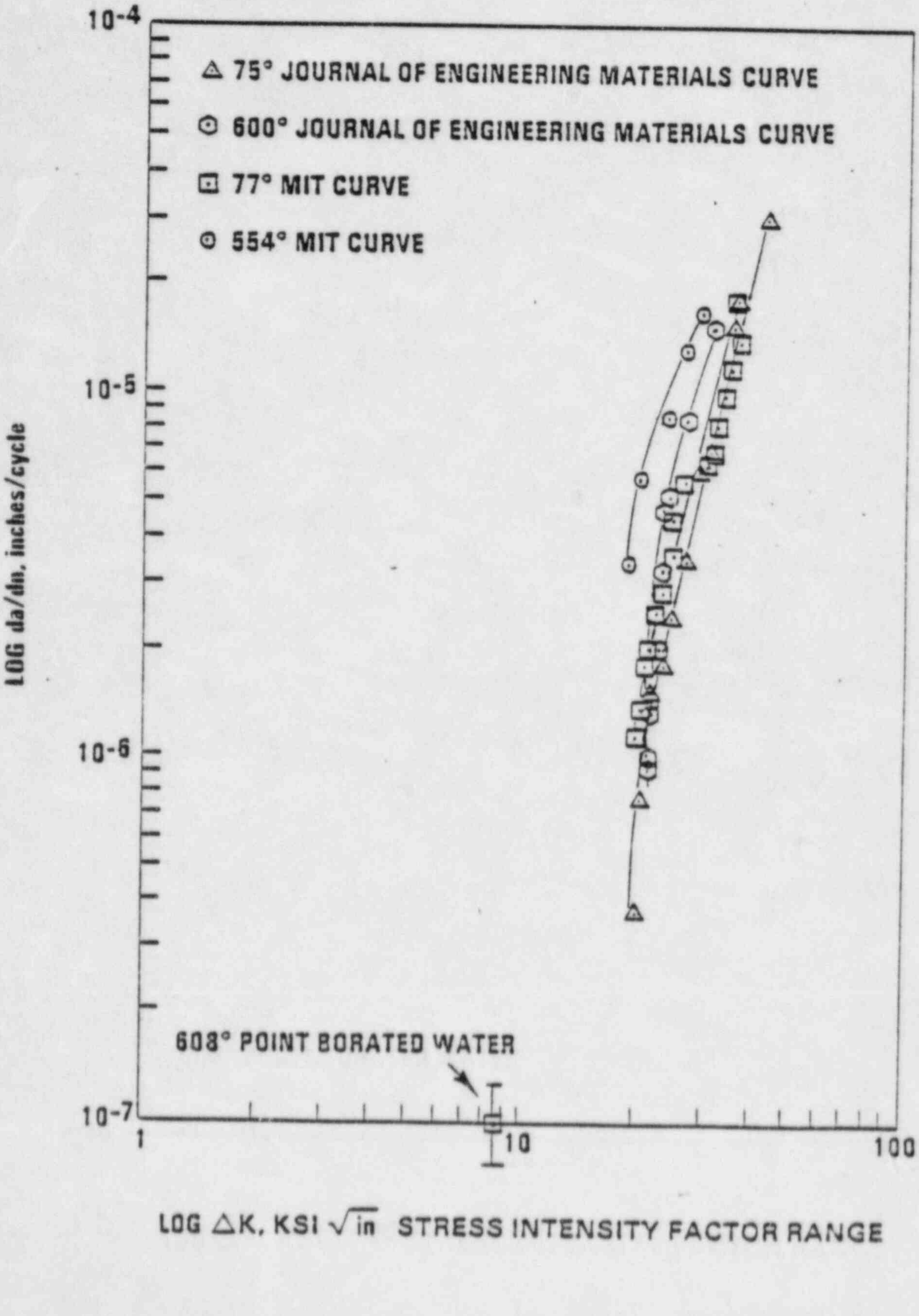


FIGURE IX-5

OTSG Leak Rate as a Function of Crack Length & Tube Tensile Load

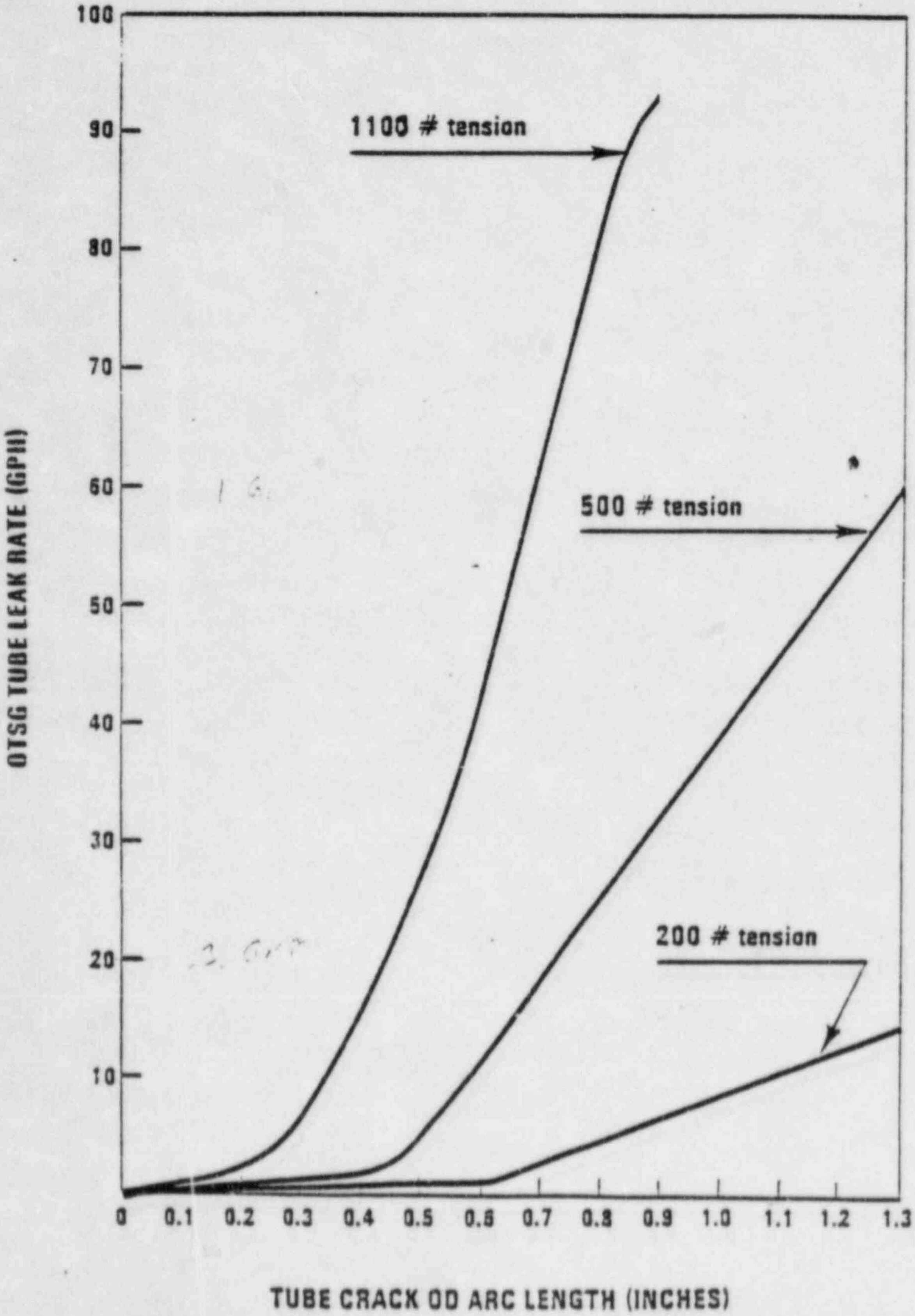
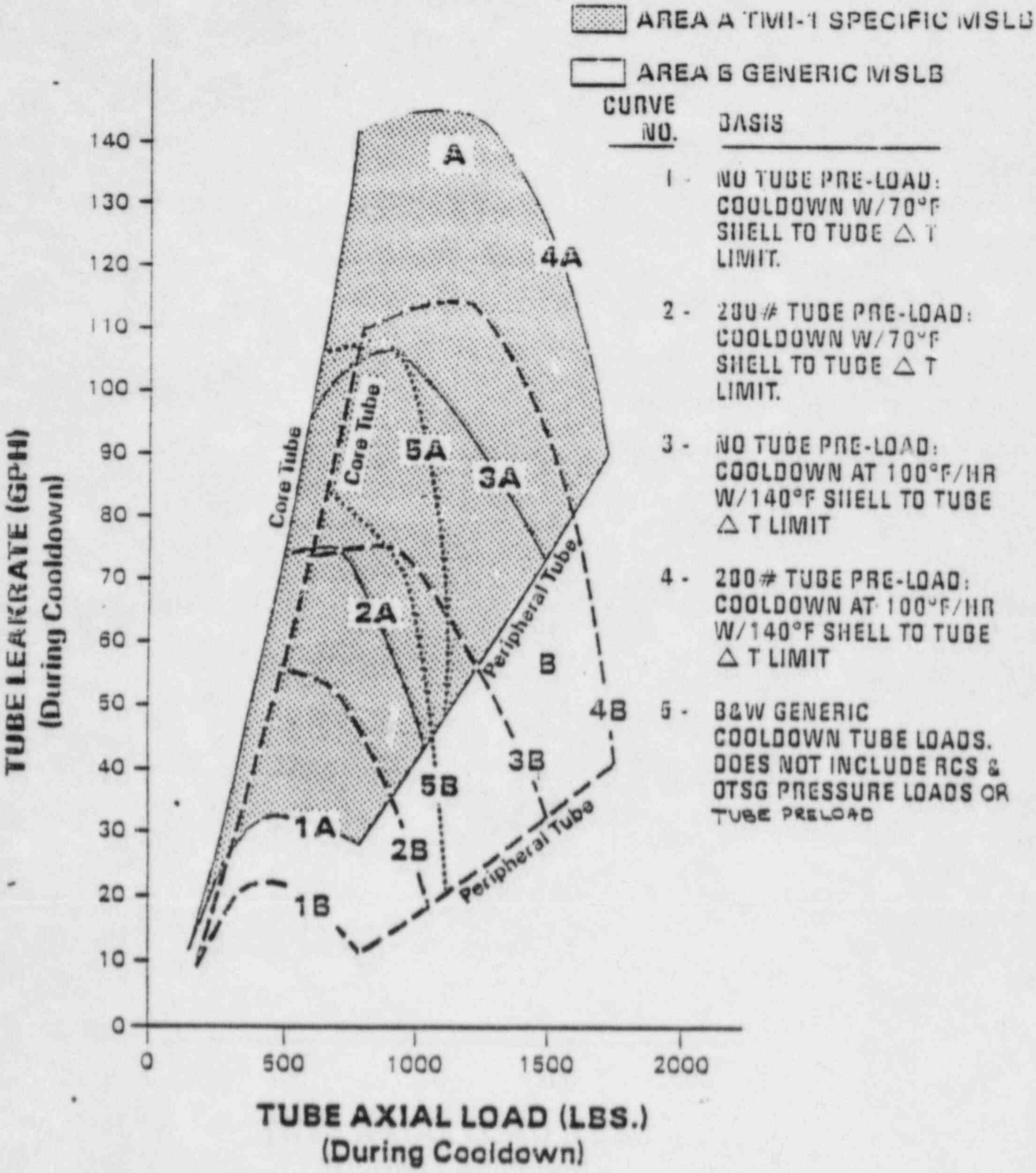


FIGURE IX- 6

TMI-1 OTSG
Tube Leakrate During Plant Cooldown From MSLB Pre-Critical Crack in One Tube at Various Cooldown Conditions



will be found. However, there is a small probability that some large cracks may not have been detected due to problems such as high noise levels, probe lift off or chatter, or data analysis errors. There is also a small probability that small cracks could grow circumferentially with time. Because of these possibilities, an evaluation was performed to determine if tube cracks of the size that would propagate can be detected due to leakage during the hot testing program and during subsequent operation.

Leakage through a 100% through-wall crack of a given length is a function of crack opening displacement (COD). The COD of a circumferential crack is a function of the axial loading of the tube. As discussed above in the OTSG tube stress analysis, the tube axial load is a function of several variables and may have either tensile or compressive values. A calculation was performed on the basis of first principles in order to establish the tube loading under various operating conditions. This calculation included the effects of differential thermal growth between shell and tube, pressure loadings and tubesheet deflection as well as a value for tube preload. The nominal preload value of 280 pounds was based on gap measurements between parted tube surfaces as measured in the TMI-1 OTSGs. The minimum preload value was taken to be zero, assuming all preload had been relieved prior to expansion. The calculated results of tube loading based on first principles correspond fairly well with the values calculated in the generic evaluation (Ref 52).

CODs have been calculated using these tensile tube loads for the MSLB through wall crack sizes using an NSAC model. After determining a conservatively small minimum crack opening displacement, leakage through the opening was calculated. The evaluation includes consideration of phase changes and pressure drop as the primary fluid passes through the crack. Figure IX-5 shows the relationship of tube leakage versus crack arc length for various tube loads which control the COD. Figure IX-5 was developed by NSAC based on a model for two phase flow through a crack with initially saturated or subcooled fluid (Ref 66).

The greater the tube loading, the smaller the initial crack size will be to produce an equivalent leak rate. Because tube loading is greater during cooldown than during any other normal operation condition, leakage monitoring will be conducted during cooldown. The following table (IX-2) shows the cooldown leak rates for peripheral and core tubes through a crack of a size that will not propagate to the through-wall MSLB critical crack size during numerous cooldown/heatup cycles. For purposes of this discussion, this crack is called a "precritical crack." Figure IX-6 shows leakage through this precritical crack for the nominal range of potential tube loadings and locations.

Table IX-2
TMI-1 OTSG Tubes
Pre-Critical Crack Sizes and Cooldown Leakrate

Tube Location	Core				Periphery			
Crack Size Basis	Generic MSLB		TMI-1 Specific MSLB		Generic MSLB		TMI-1 Specific MSLB	
MSLB load (lbs)	3140		2500		1400		1000	
Precritical Crack Size (inches)	1.25		1.5		0.5		0.53	
Cooldown Tube Load Basis (see note below)	A	B	A	B	A	B	A	B
Cooldown w/70°F T Limit (Normal Cooldown)								
Cooldown Tube Load (Lbs)	150	400	150	400	800	1050	800	1050
Leakrate @ Cooldown (GPH)	8	40	11	52	12	19	29	44
Cooldown w/140°F T Limit (Hot Testing Cooldown)								
Cooldown Tube Load (Lbs)	600	800	600	800	1500	1750	1500	1750
Leakrate @ cooldown (GPH)	73	110	96	144	34	42	74	92

Note:

A= Tubes which have had preload relieved
B= Tubes with 280# nominal preload

Figure IX-6 and Table IX-2 can be used to conclude that pre-critical cracks which may exist in the TMI-1 OTSGs can be detected by leakrate monitoring during the Hot OTSG Test Program. Specifically, one cooldown will be conducted at approximately a 90°F/hr rate with a tube-to-shell differential temperature approaching 140°F. Considering the TMI-1 specific MSLB loads, the majority of the OTSG tubes would have leakrates from any existing pre-critical cracks within the graphical area represented between line 3A and line 4A. The minimum leakrate represented by this area is about 75 GPH which is easily detectable.

Any cracks growing circumferentially the pre-critical size will be subject to cooldowns conducted in accordance with GPUNC's normal operating guidelines (70°F shell to tube differential temperature limit). The majority of the OTSG tubes would have leakrates from any existing pre-critical cracks within the graphical area represented between Line 1A and Line 2A. The minimum leakrate in this case of GPU is still readily detectable. Because cooldown/heatup thermal load cycling is the only significant contributor to mechanical growth of circumferential cracks, leakage evaluation after cooldown loading is expected to be representative through the following cooldown.

The leak rate predicted for cooldowns indicated in Table IX-2 and in Figure IX-6 are above the detectable leakage shown in Section X.

Several factors which will increase leakage through a given size crack were not considered in developing the evaluation above. These include the removal of crack surface material from erosion and grain drop-out, and the fact that existing circumferential cracks which have experienced a tensile axial load will retain a residual crack opening displacement. If a crack was opened on cooldown, empirical evidence (Ref. 62) indicates that plastic deformation at the crack tip keeps the crack from closing when the cooldown load is relieved.

The OTSG leakrate will be monitored during each plant cooldown. High leakrates would be investigated prior to restart. If the plant is restarted, operation will be subject to an administrative limit on steady state leakage which has been established with margin below the lowest leakage value in Table IX-2. Implicit in setting this limit is reliance on a residual crack opening displacement remaining after cooldown. The administrative leak rate limit assumes all increases in leakage to be from one OTSG tube and has a value of 6 gph above the baseline.

Exceeding the administrative limit will require bringing the plant to cold shutdown and leak testing the OTSG and repairing any identifiable leaks. Bubble tests are expected to identify individual leaking tubes. Bubble test sensitivity is approximately .1 gpd/tube. Thus, any cracks in service of a size which is or may propagate circumferentially to a critical size will be identified.

In addition to the steady state leakage limit, normal plant cooldowns will be accomplished at less than 100°F/hr and limit the OTSG shell to tube delta T to 70°F. This limit will reduce tube stress which could be lead to mechanical crack propagation but will still provide adequate stress on cooldown to open pre-critical cracks to a large enough residual COD to enhance leakage detection.

E. <u>Conclusions</u>

Evaluations of tubing left in service have been performed to verify that they are acceptable for use. The possibility for additional corrosion occurring after return to operation has been considered and found unlikely. In considering existing damage, the ability of cracked tubing to withstand steady state, transient and accident loading has been examined. All cracks of

a size that could be expected to propagate under loading are within the range of detectability by eddy current testing. If a through wall circumferential crack of critical size for growth has been inadvertently left in service will be detectable due to leakage during the precritical OTSG test program. Cracks below that size which grow circumferentially under cooldown/heatup loading will also be detectable due to leakage before they reach the cirtical size.

X. OPERATIONAL CONSIDERATIONS

The operational concerns of primary to secondary leakage were evaluated. Concerns included leakage monitoring during normal operations in both steaming and nonsteaming conditions, and sampling steps to be taken when leakage is detected. In addition, a program has been formulated that includes procedure review and operator training which will provide improved operator guidelines for dealing with tube leakage and tube rupture events.

The operational guidelines discussed in this section are applicable during normal operation with low levels of primary to secondary leakage. A more detailed description of these guidelines can be found in reference 58. For primary to secondary leakage ratio of 50 gpm or greater, these guidelines will be superseded by tube rupture guidelines as discussed in Section X.D.

Operational concerns can be grouped into three general areas:

1. Primary to Secondary Leakage which includes leakage detection methods, and actions required based on primary to secondary leakage.

2. Radiological concerns which include detection methods, worker protection measures and plant discharge limits.

3. Secondary side chemistry limits based on boron and lithium concentrations.

This section summarizes the guidelines for operating with tube leakage.

A. Primary to Secondary Leakage

During normal operation the methods which will be used to detect and monitor leakage are:

1. Offgas continuous monitor (RMA-5)

2. Tritium samples from the condensate and primary system.

3. Offgas grab samples

TC H. Silver, NRC
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September 30,1983
5211-83-279

Office of Nuclear Reactor Regulation
Attn: J. F. Stolz, Chief
Operating Reactors Branch #4
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Sir:

Three Mile Island Nuclear Station, Unit 1 (TMI-1)
Operating License No. DPR-50
Docket No. 50-289
Comments on NRC SER Concerning TMI-1
Steam Generators Repair

This letter is intended to convey GPUN's response to your August 25 safety evaluation on TMI-1 return to service with repaired steam generators. Attachment 1 to this letter documents GPUN actions on confirmatory items in your SER. Attachment 2 is a list of GPUN comments on the Staff SER.

We hope these items will support preparing the scheduled supplement to your SER.

Sincerely,

H. D. Hukill
Vice President - TMI-1

cc: H. Silver

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Attachment 1

GPUN Actions on Confirmatory Items

Section	Page, Paragraph		Item/Response
4.3.1	39(2nd)	Item:	"...an updated TDR 406 confirming the modifications discussed above and containing acceptable documentation of the analytical justifications for these modifications is submitted prior to restart."
		Response:	TDR 406, Rev. 2 is enclosed. Supporting references and procedures have been made available to members of your staff.
4.3.2	42(item 5)	Item:	Reactor Coolant Pump NPSH for Emergency Operations, "The licensee should insure that the copy for Control Room use is clear and legible".
		Response:	The Controlled Copy of the approved and formally issued 1202-5 has clear and legible copies of the NPSH curves. A copy of the procedure has been made available for review by members of your staff.
4.3.2	43(item 7)	Item:	S/G Isolation/Steaming Criteria, "...the licensee will make a change for SG isolation from a dose to dose rate criteria."
		Response:	The Controlled Copy of the approved and formally issued 1202-5 has dose rate rather than dose isolation criteria. A copy of the procedure has been made available for review by members of your staff.
4.3.2	43-44(item 8)	Item:	Pressure Control of Isolated SGs - "The licensee states that instructions for controlling pressure in an isolated SG are planned for inclusion in EP 1202-5".
		Response:	Although the subject of this quote is feeding an isolated OTSG for pressure control, the SER mistakenly refers to "steaming" an isolated SG in the sentence before the quote.

Section	Page, Paragraph		Item/Response
			TDR 406, Rev. 2 no longer recommends feeding an isolated OTSG for pressure control (see last item of Summary of Change, page 9 of 74 TDR 406, Rev. 2). It should be noted, however, that due to an editing error a reference to this form of OTSG pressure control still exists in section 3.2.4 page 30 of 74. This error will be corrected with the next revision to TDR 406. EP 1202-5 reflects the revised TDR 406, Rev. 2.
4.3.2	44(item 9)	Item:	SG Shell to Tube Differential Temperature Limit. "The licensee will be required to clarify procedural action for Delta T's in excess of 100°F."
		Response:	The Delta T limit in the procedure is 70°F. If this limit is approached the guidance in 1202-5 does require that the cooldown rate be reduced or secured so as not to exceed 70°F. The guidance for a 100°F Delta T has been removed from TDR 406, Rev. 2 (see abstract and section 3.2.2.3 of TDR 406, Rev. 2). It should be noted, however, that due to an editing error, section 5.2.9 still contains the confusing second reference to a 100°F limit. This error will be corrected with the next revision to TDR 406. EP 1202-5 reflects the revised guidance in TDR 406, Rev. 2.

Section

2

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Section	Page, Paragraph		Item/Comment
3.3	15(table)	Item:	Table 3.3-1.
		Comment:	The numbers of tubes listed in the last two columns are approximations only. In some cases more were done in the baseline and will be repeated after 90 days. In some cases fewer were done because the population of tubes in that category was less than shown in the table due to plugging of adjacent tubes or the tubes location in the periphery.
3.3	16 (top)	Item:	"As early as feasible in post critical operation, the licensee shall confirm the baseline primary-to-secondary leakage rate, and establish the minimum increase in such leakage rate which can reliably be measured (expected to be about .1gpm) . If leakage exceeds the baseline leakage rate by that minimum increase, the plant shall be shut down and leak tested".
		Comment:	As discussed in TR-008, GPUN has established .1 gpm as an administrative limit on leakage above baseline. This leakage rate is detectable.
3.4.1.b	16(bottom)	Item:	Planned testing.
		Comment:	The second phase of testng is complete and results have been reported in TR-008, Rev. 3. Assessment of the joint for the full 35 year design life will be performed when data on actual steam generator performance is available to supplement the results of the 5 year and 15 year test programs. No additional testing is planned prior to the startup after the first refueling outage.
3.4.1.c	17 (top)	Item:	"This objective assures that compressive loads during operation and vibrational characteristics of the tube will remain unchanged."
		Comment:	As stated in TR-008, only the maintenance of vibrational characteristics is an objective. It is also a goal that the tubes not be in compression when cold.

Section	Page, Paragraph		Item/Comment
3.4.2.d	20(3rd)	Item:	"...the 1025 pounds necessary to cause tube bowing."
		Comment:	As discussed in TR-008 and our letter of August 3, tube bowing begins at approximately 800 lbs, but loads must reach 1025 lbs before the lateral displacement of the tube exceeds the nominal size of the space between tubes.
3.4.2.d	21(4th)	Item:	"...1.0 ksi $in^{1/2}$."
		Comment:	Calculations were done at 4.0 ksi $in^{1/2}$.
3.4.2.d	21(bottom)	Item:	Stable cracks.
		Comment:	This paragraph may need revision based on TR-008,. Rev. 3.
3.4.2	23(bottom)	Item:	"The Staff will condition the license to require submittal of the extended life cycle program qualification test results by Startup after the first regularly scheduled refueling after restart."
		Comment:	See comments for p. 16, section 3.4.1.b.
3.5	28-29	Item:	Cleanup of Contaminant
		Comment:	Some parameters throughout in this section may need to be updated to reflect actual chemical cleaning as discussed in TR-008, Rev. 3.

Boron (boric acid)	1800-2300 ppm
pH (ambient temperature)	8.0-8.5
H_2O_2 concentration	15-25 ppm
Temperature	130°F ± 5°F
Cover Gas	N_2 (pzr)
Lithium ion concentration	1.8-2.2
Duration of Treatment	400 hrs.

Testing using samples prior to beginning cleaning monitored performance through 500 hrs.

Section	Page, Paragraph		Item/Comment
3.6	30(item 2)	Item:	"All RCS piping..were flushed..."
		Comment:	All RCS piping with a diameter greater than 1" was flushed.

Section	Page, Paragraph		Item/Comment
3.6	30(item 4)	Item:	"The coolant will be...monitored continuously for pH and conductivity."
		Comment:	Per TR-008, as recorded in your Table 3.6-1, these parameters will be monitored five times per week.
3.6	31(table)	Item:	Table 3.6-1.
		Comment:	There are several differences in Table 3.6-1 from our plans as outlined in TR-008.

Parameter	Old Limit	New Limit
Lithium	0.2-2.0(ppm)	1.0-2.0(ppm)
Chlorides	0.15(ppm)	0.10(ppm)
Sodium	None	0.1 (ppm)

Section	Page, Paragraph		Item/Comment
3.8	33-35	Item:	Occupational Dose Assessement.
		Comment:	Final man-rem exposures and final numbers of tubes plugged are recorded in TR-008, Rev. 3.
4.3.1	39(2nd)	Item:	"This dose corresponds to levels prescribed in 10CFR, Part 20..."
		Comment:	This dose corresponds to emergency plan action levels.
4.3.2	41(item 1)	Item:	"...a 50-gpm leak rate criterion...corresponds to the complete separation of one tube."
		Comment:	A 50-gpm leak rate is approximately 10% of the leakage from a complete separation (double ended tube rupture) of one tube. The criterion corresponds to emergency plan action levels.
5.2	46	Item:	License Conditions 4 and 5.
		Comment:	See comments for page 16, section 3.3. and page 16, section 3.4.1.b.

4. N-16 activity measurements using portable steam line monitors

5. Primary Leak Rate Calculation

These leakage detection methods are summarized in Table X-1, as well as the frequency use during operations and during cooldown.

RMA-5 will be the first indication of increased primary to secondary leakage. The monitor will continuously sample the vacuum pump exhaust from the main condenser. Upon a 1 gph increase in leakrate in 8 hours or a 6 gph increase during a cooldown as calculated from RMA-5, offgas grab sample and an RCS sample will be taken and the primary to secondary leak rate will be calculated using total gas activities. The portable steam line monitor will detect N-16 activity and will be used to evaluate which steam generator is leaking.

Primary leak rate calculations which are done daily per Technical Specification requirement can also identify increased primary to secondary leakage. Since the leak rate cannot distinguish between unidentified system leakage and primary to secondary leakage, if an unidentified increase in leak rate occurs, a tritium and offgas grab sample will be taken to allow for an accurate determination of the primary to secondary leak rate.

Shutdown limits based on primary to secondary leakage will consist of the Technical Specification limit of 1 gpm and an administrative limit of 6 gph above a baseline leakage. Baseline leakage will be determined during the precritical hot testing program. When a steady state leakage increase of 6 gph is reached the plant will be brought to a cold shutdown, the OTSG will be leak tested and the leaking tubes repaired. Tube leakage will be tested by the bubble test method. This method has a sensitivity of approximately .1 gal/day/tube or $4x10^{-3}$ gph/tube, therefore if no leakage is detected during the bubble test it can be assumed that no individual tube has reached the critical crack size and primary to secondary leakage may be due to aggregate tube leakage. The baseline leak rate value will be redetermined based on an evaluation of the OTSG leak rate test results and operating history after the leak test is performed. When primary leakage reaches 6 gph greater than the new established baseline the plant will again be shutdown and leak tested.

When shutdown is required by steam generator tube leakage, the plant should be shutdown expeditiously but in a manner to preclude reactor trip and subsequent lifting of relief valves or atmospheric dump valves. Cooldown rates will be limited by a tube to shell delta T of 70° to reduce tube loading during cooldown.

B. Radiological Concerns

During normal operation with steam generator tube leakage, radiological concerns arise in the following areas:

1. General and specific area radiation level

2. Turbine building sump activity (with respect to discharge to the environment).

3. Powdex resin and backwash water activity.

Specific and General Area radiation limits will be determined and will be based on preventing the turbine building from becoming an RWP area (greater than 5 mr/hr). Limits are needed due to the necessity for easy access into the turbine building during operation. Routine radiation surveys will be taken in the turbine building in the vicinity of the Powdex and Graver System vessel and in other selected areas. These areas will be restricted if necessary to prevent unnecessary exposure to plant personnel. Precautions will also address secondary side system vent and drain operations.

In the Powdex sump, pH and conductivity analysis will determine if the water which has been processed by the (Ecodyne Graver) Powdex Backwash Recovery system will be returned to the TMI-I condensate system or to the turbine building sump. Any radioactive powdex will be dewatered in High Integrity Containers/Liners and shipped to commercial low level waste burial sites.

C. Secondary Side Chemistry

Secondary side chemistry limitations for Boron and Lithium will be based on considerations of chemical introduction into the turbine.

D. Development of Procedural Guidelines for Steam Generator Tube Rupture

A program has been formulated for providing improved operator guidelines for dealing with tube leakage and tube rupture events. The guidelines cover two categories of events. The first category addresses tube ruptures for which subcooling margin is maintained. The second category deals with tube ruptures for which subcooling margin is not maintained and would include various contingencies including multiple tube ruptures in one or both SG's, loss of reactor coolant pumps and loss of condenser.

1. Contingencies for Consideration

The following is an outline of the programs for developing guidelines for SG tube rupture.

a. Guidelines for Tube Ruptures for Which Subcooling Margin is Maintained

The program to develop guidelines for tube ruptures for which subcooling margin is maintained will include the following basic assumptions.

TABLE X-1

LEAKAGE DETECTION METHODS SUMMARY TABLE

Method	Sensitivity	Frequency	Special Actions
RMA-5	0.48 gph with 3.8 uCi/cc and 20 cfm exhaust flow	Continuous strip chart reading.	When leak rate calculated by RMA-5 increased by lgph in 8 hours, or 6 gph during cooldown sample take off-gas grab sample and RCS sample
Tritium	.3 gpm at .02 uCi/ml H_3 after 8 hours		
Offgas Grab Sample	.01 gpm at 3.8 uC /cc and 20 cfm exhaust flow	24 hours	Frequency increased with known leakage
Portable Steam Line Monitor		When leakage is detected determine which generator is leaking	

(1) Break size small enough to maintain subcooling margin.
(2) One OTSG affected.
(3) Reactor Coolant Pumps operating.
(4) Condenser available.
(5) Decay heat removal from the non-affected SG.
(6) SG steamed at 95% operating range level to assure natural circulation.

Contingency considerations for design basis tube ruptures include:

(1) PORV unavailable.
(2) Reactor Coolant Pumps unavailable.
(3) No condenser available.
(4) High radiation release considerations.
(5) Steam line flooding consideration.
(6) Both SG's are affected.

b. <u>Guidelines for Tube Ruptures For Which Subcooling Margin is Not Maintained</u>

The program to develop guidelines for tube ruptures for which subcooling margin is not maintained will include the following basic assumptions.

(1) Break size from one SG large enough to cause loss of subcooling.
(2) No reactor coolant pumps running (since subcooling margin is lost).
(3) Condenser available.
(4) PORV available.
(5) Unaffected SG is steamed.

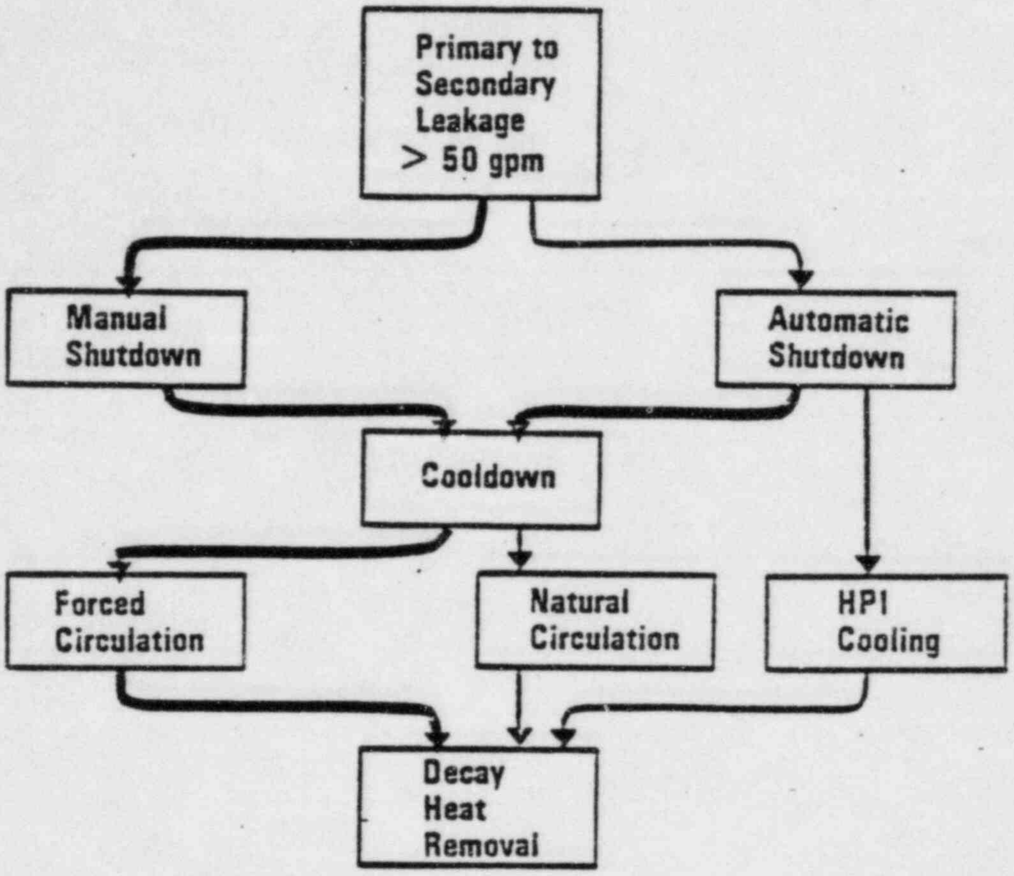
Contingency considerations include:

(1) PORV unavailable.
(2) RCS voiding keeps pressure above SG safety valve setpoint.
(3) Primary feed and bleed heat removal.
    (a) With PORV available
    (b) Without PORV available

Both the analyses employ the RETRAN code. This code models TMI-1 and has been benchmarked from transients on both TMI-1 and TMI-2. Use of this code ensures that plant response under various primary-to-secondary leak scenarios is understood.

FIGURE X-1

Tube Rupture Guidelines



New Guidance:

- multiple tube ruptures
- ruptures in both steam generators
- HPI cooling
- Secondary water management

Improved guidance

- Minimum subcooling reduced
- RCP trip criteria
- tube to shell ΔT
- steam generator steaming, feeding, flooding

The guidelines developed from the RETRAN analysis for tube ruptures are summarized below and have been used for writing new procedures and revising old procedures. Operator training prior to restart includes response to tube rupture events using new and revised procedures.

2. Guideline Summary

The symptoms of a tube rupture define entry conditions for this emergency procedure. It is only used when leakage exceeds 50 gpm. When conditions require it (as defined by high leakage or significant offsite releases), the plant will be shutdown and cooled as expeditiously as possible, and certain normal plant limits (RCP NPSH, normal tube/shell delta T, and fuel-in-compression limits) are waived.

a. Immediate Action

The tube leak in question may not be large enough to cause a reactor trip. In such a case, the operator begins a load reduction as rapidly as possible without causing a reactor trip (10%/min.). Avoiding a reactor trip prevents lifting of the OTSG safety valves.

b. Followup Actions

(1) Subcooling Maintained and Reactor Coolant Pumps Available -

Once the load reduction is initiated or a reactor trip has occurred, the operator has several major goals to achieve while bringing the plant to a cold shutdown condition. First, he prevents lifting of the OTSG safety valves; second, isolates the affected OTSG to prevent unnecessary radioactivity releases; third, minimizes primary to secondary leakage by minimizing primary to secondary differential pressure; and, fourth minimize stresses on the OTSG tubes by limiting tube/shell delta T. Finally, the operator will minimize offsite dose by allowing the leakage OTSG to flood if offsite doses are large enough (approaching levels at which a Site Emergency would be declared).

The major differences between the previous plant procedure and the new procedure are be the following.

(a) Maintain a Minimum Subcooling Margin

Minimum subcooling margin means that primary to secondary differential pressure is minimized. Minimum differential pressure means that leakage is reduced; thus reducing off site dose and making the event more manageable. In order to maintain the minimum subcooling margin, several plant limits have to be violated: fuel in compression limits and RCP NPSH limits. The former is acceptable to violate during emergency conditions, while the latter is being reevaluated to determine acceptable emergency operation of the pump.

(b) Steaming/Isolation Criteria for the Affected OTSG

The present procedure allows the operator to let the OTSG flood anytime that RCS pressure is below 1000 psig. The revised procedure has the operator steam the OTSG as necessary for the following purposes. First, to prevent lifting of the OTSG safety valves. As the OTSG level increases, steam generator pressure in the isolated generator could increase toward the safety valve setpoints. Pressure should be controlled to prevent a safety valve lift.

The generator is also steamed to prevent it from flooding. Flooding is undesirable because an RCS pressure increase under this condition could cause water relief out of the OTSG safety valves. A flooded OTSG would also act as a second pressurizer and slow depressurization of the RCS (as occurred in the GINNA tube rupture).

The OTSG will be isolated under two conditions. First, if BWST level goes below 21 ft. indicated level. At this level, there is still sufficient inventory to fill up both OTSG's to the main steam isolation valves and have 30,000 gallons of water left to go on feed and bleed cooling. A second reason to isolate the OTSG is for radiological considerations. If the Radiological Assessment Coordinator (RAC) determines that offsite doses are approaching

the levels which would require declaration of a Site Emergency, (regardless of cause) the affected steam generator will be isolated.

(c) Tube-to-Shell Delta T

Plant administrative limits and precautions will require maintaining the OTSG average tube temperature within 70°F of the average shell temperature.

(2) Loss of Subcooling Margin with Natural Circulation Cooling

When RCS subcooling is lost, the operator must treat LOCA, as well as tube rupture symptoms. First he trips RCP's and then verifies HPI and EFW have initiated. He is then able to pursue the followup tube rupture actions. All of the guidance for followup actions without loss of subcooling apply, as well as the additional guidance provided below.

The objective in this portion of the procedure is to maintain natural circulation, reestablish subcooling margin, restart a reactor coolant pump, and return to the section of the procedure for forced flow cooldown.

When subcooling is regained in the RCS, then HPI is throttled, RCP's are started and the operator continues with 1.67F/min cooldown. If subcooling cannot be restored, the operator cools the plant down on natural circulation, steaming as necessary to meet the objectives described in the forced flow section.

(3) Loss of Subcooling and Loss of Heat Sink

Natural circulation cooldown will continue until subcooling is restored or the OTSG heat sink is lost (for example, due to loss of natural circulation in the unaffected loop). With no steam generator heat sink, the operator must put the plant in a feed and bleed cooling mode. Feed and bleed cooling is initiated by isolating the OTSG's, assuring full HPI is operating, and opening the PORV. If RCS pressure remains below 1000 psig, then the operator continues to control secondary side pressure just below RCS pressure. If the OTSG heat sink is restored, the feed and bleed is terminated and a natural circulation cooldown is reinitiated.

If RCS pressure stays above 1000 psig during feed and bleed cooling (e.g., a head bubble prevents depressurization or the PORV fails closed) then the secondary side safety valves should be protected from challenge. The operator controls OTSG pressure with whatever means are available (turbine bypass, EFW or ADV). When the OTSG is about to flood, the operator opens the ADV and leaves it open. This action minimizes the chances that safety valves will be forced to relieve water and/or steam and fail open. The steaming capacity of an ADV at 1000 psig exceeds decay heat levels within several minutes after reactor trip. HPI capacity exceeds the capacity of one ADV. Therefore, the RCS pressure can be controlled at 1000 psig in this mode without lifting safety valves. Subcooling margin can be regained and the plant cooled down in this mode until an OTSG heat sink can be restored or until the plant can be put on decay heat removal.

A simplified schematic of the tube rupture guidelines is shown in Figure X-1. A fourth possible scenario exists under current procedures which has not been considered a preferred course of action in formulating the guidelines: maintenance of subcooling margin but tripping of reactor coolant pumps on 1600 psi RCS pressure. Pump trip on loss of subcooling margin instead of RCS pressure allows the operator to maintain forced flow for about 3 ruptured tubes - 1600 psig SFAS is much more restrictive. Forced RC flow provides several benefits during a tube rupture.

1. It minimizes primary to secondary delta P and thus reduces tube leakage and tube tensile load.

2. Prevents steam formation in the RCS. (Steam voiding prevents RCS depressurization.)

3. Provides pressurizer spray so that RCS pressure control is not dependent on the PORV or pressurizer vents.

Therefore, GPUNC is taking action to have the 1600 psi pressure pump trip requirement changed to trip on subcooling margin.

E. Conclusions

Primary to secondary leakage will be monitored during non-steaming and steaming conditions. Sampling requirements on the detection of a primary to secondary leak have been established, as well as administrative limits on leakage.

The combination of analysis of tube ruptures, procedure improvement and training improvement give assurance that operators can safely respond to a primary to secondary leak.

XI. ENVIRONMENTAL IMPACT

A. Introduction

The impact of operating TMI-1 with primary to secondary leakage was evaluated. Offsite dose estimates were determined at several leakage rates, using actual anticipated failed fuel percentages. These calculated estimates have been compared with Appendix I technical specification requirements. The effect of leakage on onsite exposure was also considered and found to be small. Exposures associated with steam generator work leading to return to service are also discussed below.

B. Offsite Dose Estimates

The maximum primary to secondary leakage rate at which TMI-1 might operate can not be determined without operating experience. The offsite consequences of such operation will be dependent on the failed fuel percentage and actual plant system and environmental conditions. Dose will be determined during operation by monitoring. The technical specifications for TMI-1 incorporate the Appendix I offsite dose limitations. If offsite doses approach these limits due to primary to secondary leakage, it will be necessary to shut the plant down to look for leaks.

For planning purposes, two calculations were performed using different hypothetical leaks rates, 1 lbm/hr and 6 gph. 1 lbm/hr is the repair leak rate goal. 6 gph was selected as a leak rate with which similar plants have operating experience, and which is similar to the leak rate change at which administrative procedures TMI-1 would shutdown to look for leaks. Both calculations assumed 0.03% failed fuel, which was seen at TMI-1 at the end of cycle 4. Results of the two estimates are compared in Table XI-1 to Appendix I technical specification limits. Source terms and methods for calculation can be found in Reference 11 and 54.

Table XI-1
Hypothetical Maximum Individual Offsite Dose(1)

Source	OFFSITE DOSE AND FRACTION OF APP. I LIMIT				10 CFR 50 App. I Limit (mr/yr)
	1.0 LBM/HR		6 GPH		
	Dose (mr/yr)	% of App. I Limit	Dose (mr/hr)	% of App. I Limit	
Iodine & Particulates	7.68E-2	0.5	4.61	31	15
Noble Gases					
° Gamma	5.68E-2	0.6	2.74	27	10
° Beta	6.96E-2	0.4	3.33	17	20
Liquid Effluent					
° Whole Body (adults)	1.04E-3	0.1	4.88E-2	1.6	3
° Liver (teens)	1.52E-3	0.1	7.28E-2	0.7	10

(1) Based on 80% of the plant capacity factor.

As can be seen in Table XI-1, offsite doses are not expected to approach Appendix I limits due to primary to secondary leakage. However, monitoring of actual offsite exposure will be used to set leakage limits which prevent exceeding technical specification limits.

C. Exposure Estimates

The man-rem exposures measured on self-reading dosimeters for the completed OTSG repair program were 1233 man-rem. Individual activities for the steam generator program are presented in Table XI-2, along with exposures for each task.

Table XI-2
Exposures from OTSG Program
(based on self-reading dosimetry)

	Task	Man-Rem
1.	RCS Inspection	12
2.	Eddy Current Testing	39
3.	Pre-Repair Testing	5
4.	Tube Sample Pulling Plugging and Stabilization	120
5.	Plugging and Stabilization	
	a. W plugs	37
	b. Stabilization	138
	c. Post-testing plugging, stabilization and plug repair	85
6.	Kinetic Expansion	
	a. Pre-expansion Preparation	16
	b. First Pass Expansion	168
	c. First Pass Debris Removal	132
	d. Second Pass Expansion	167
	e. Second Pass Debris Removal	75
7.	End Milling	125
8.	Clean-up	
	a. Flush	18
	b. Soak and Clean	5
	c. Individual Tube Cleaning	71
9.	Testing	
	a. Drip Tests	12
	b. Bubble Tests	5
	c. Final Inspection and Turnover	3
	Total	1233 Man-Rem

Table XI-3
Radiation Fields at TMI-1

Location		
Upper and Lower Heads	1.3	R/hr.
Manway	0.13	R/hr.
Tent	0.01	R/hr.
Low Zone	0.001	R/hr.

Operating with the limited leakage associated with the repaired joint was also considered. The additional exposure is expected to be low. Normal health physics and ALAR practices will identify any additional radiation areas and minimize related worker exposure in operating with a primary to secondary leak. The largest sources of radiation exposure are expected to be the Powdex Demineralizer vessels. Associated contact radiation levels have been calculated for a 6 gph leak to range from 0.7 mr/hr for one day filter operation to 5.7 mr/hr for 15 day operation. In addition to these estimates, experience at similar plants operating with small primary to secondary leakage has been exposure increases of less than one man-rem per year. Based on this information, the annual exposure at TMI-1 is expected to increase by less than 1% due to leakage.

D. Sampling and Monitoring

Appropriate monitoring and sampling of all waste streams will be conducted per established Guidelines. Modifications will be installed in the Turbine Building to provide radiation and contamination control and effluent release control/accountability. These modifications will consist of Powdex and Turbine Building sump painting, and liquid monitors to measure activity during operation.

E. Conclusions

The operation of TMI-1 with small primary to secondary leakage is not expected to cause offsite doses nearing the Appendix I Technical Specification limits. Final verification of estimates will be by monitoring during operation. Should monitoring indicate that primary to secondary leakage is causing offsite doses to approach these limits, steps will be taken to reduce the activity contribution. Exposures onsite as a result of primary to secondary leakage are expected to be minimal compared to prior plant experience. Exposure during the investigation of the steam generator problem, the repair, and testing afterwards, was measured as 1233 man-rem on self-reading dosimeters.

XII. TECHNICAL SPECIFICATION COMPLIANCE

This safety evaluation demonstrates that the TMI-1 OTSGs are operable per T.S. 3.1.1.2, and have met the surveillance conditions for operability given in T.S. 4.19, or as defined in the related T.S. change request. Specifically, the eddy current testing required by Table 4.19.2 has been completed and all tubes found by ECT to have indications below the top of the repair which either exceed the repair limit or to contain throughwall cracks have been repaired or plugged. As further described in Appendix A, the bubble test results in OTSG "B" showed no observable leaks and those in OTSG "A" showed only very small amounts of leakage which we have concluded are too small to declare the tubes unserviceable or to warrant further action prior to proceeding.

In addition, the following technical specifications were evaluated in light of the selected repairs. Operation with the repairs in place was found to be acceptable in each case.

T.S.	Subject	Topic for Evaluation	SER Reference
1.5.6	Heat Bal. Calib.	Flow asymmetry	Section VIII
1.6	Def'n, Quad. Pwr. Tilt	Flow asymmetry	Section VIII
2.1	Fig. 2.-1,2.1-3 Flow vs T	Flow, flow asymmetry	Section VIII
2.3	Fig. 2.3-2, Table 2.3-1 Nuclear Overp.	Flow	Section VIII
3.1.1.1.a	Permissible pump. comb.	Flow	Section VIII
3.1.2	RCS heatup-cooldown	Stress vs. Temp. change: assumes vessel as limit	Section V and IX
3.1.4	RCS activity	Leakage	Section X
3.1.5	RCS chemistry	Further attack in conj. w/resid. S or following S distress	Section IV
3.1.6	RCS leakage	Leakage	Section IX
3.5.2.4	Quad Pwr. Tilt	Flow asymmetry	Section VIII
3.5.2.5	Quad. Bal.	Flow asymmetry	Section VIII
3.13	Secondary activity	Appendix I w/leakage	Section X
3.22	Appendix I	Leakage	Section X
3.23	Appendix I	Leakage	Section X
4.2	RCS:ISI	Testing of RCS Components	Section II.E
5.3.2.1	RCS code req.	Repair qualification	Section V

XIII. SUMMARY AND CONCLUSIONS

The previous twelve sections along with the references and appendices associated with this safely evaluation provide a broad-ranging discussion of the adequacy and safety of the TMI-1 OTSG repair and the ability of the plant to be safely returned to service. The main points associated with determining that the plant is safe to operate can be summarized as follows:

1. Knowledge of the failure scenario is sufficient to provide a firm technical basis for OTSG repair decisions, insure that the environment for such a damage mechanism is not established in the future, and provide a technical basis for assuring safe performance of the OTSG tubes below the area of the new joint.

2. Evaluation of operation of TMI-1 with small primary-to-secondary leakage has confirmed that Appendix I Technical Specification considerations are satisfied.

3. All tubes with no defect indications below an elevation 8 inches above the lower face of the upper tubesheet (UTS+8) have been adequately repaired by the kinetic expansion process. The kinetic expansion process qualification program provides assurance that a load carrying and leak limiting joint acceptable for safe operation has been formed.

4. The performance of the OTSG/RCS considering the tubes to be plugged is satisfactory and no power limitations are required. Tubes with defect indications below the UTS+8 elevation will be removed from service by approved plugging methods. The OTSG/RCS performance with these tubes plugged has been evaluated for both normal operating and emergency conditions.

5. Circumferential defects smaller than the threshold detectability of ECT or less than 40% through wall are acceptable. Fracture Mechanics Analysis of circumferential tube defects has been conducted. The analysis identified crack geometries which would propagate from mechanical loads during both normal operating or accident conditions. Geometries which would propagate to a double ended tube rupture during 40 years of operation or during an accident were characterized as "unstable." The results have been compared to the ECT sensitivity for various geometries of circumferential defects. This comparison shows that the GPUNC 100% ECT inspection of the TMI-1 OTSGs was sensitive enough to find "unstable" defect geometries.

6. The examination of Reactor Coolant System (RCS) has confirmed that the aggressive environment that caused damage to the OTSG tubes and to the PORV did not damage the remainder of the reactor coolant system. The RCS examination results provide the

basis for concluding that there are no corroded components in service which will preclude the RCS from functioning properly and supporting safe operation of TMI-1.

7. Analysis of design basis and higher primary-to-secondary leak rates confirms that the operating and emergency procedures are technically correct. The procedures provide adequate basis for training the operators to respond to normal and emergency primary-to-secondary leakage. The procedures have been modified to improve even further operator guidelines and handle greater than design basis accidents.

8. Steam generator testing together with long life continuing laboratory testing will provide confirmatory data on repair stability and the absence of new high velocity cracking. The steam generator testing will be completed with essentially zero decay heat power and poses no safety risk.

Conclusion

In conclusion, TMI-1 can be safely returned to service once the repairs and other activities discussed in this safety evaluation report are completed. This conclusion is based on sound analytical and empirical data developed by GPU Nuclear Corporation during the OTSG repair program. The scope of technical evaluations has been broad based and the involvement of numerous independent technical experts has been extensive throughout the TMI-1 OTSG repair program. The methodical, technical approach to evaluating the various aspects of the problem in order to make the best and safest decisions provides a high degree of confidence that TMI-1 steam generators can be safely operated.

APPENDIX A

PRECRITICAL AND POST CRITICAL TEST PROGRAMS

I. INTRODUCTION

The TMI-1 restart test program has been planned to provide a deliberate, methodical, well planned verification of proper installation and performance of the steam generator joint modifications, to verify conformance with design and licensing bases. Cold and hot precritical testing have been combined with the power escalation program to create a progressive testing program for the OTSGs. The program includes the following:

- Verification of the adequacy of the OTSG Tube Repair Program by pre-service leak testing of individual tubes
- Verification of the adequacy of the OTSG Tube Repair Program by operational leak testing and on-line monitoring throughout the test program
- Verification of the adequacy of the repaired OTSG tube joint and tubing in service to carry loads under normal operating transient conditions.
- Verification of acceptable system readiness and plant operation with new and modified plant operating, surveillance, emergency, and abnormal procedures
- Performance of sufficient modified system/plant steady state and transient operations to provide operator training and familiarization with modified system/plant response throughout a range that is likely to be experienced during the design life of the plant

The scope and chronology of testing planned to meet these goals are discussed below. The test sequence is summarized in Figure A-1.

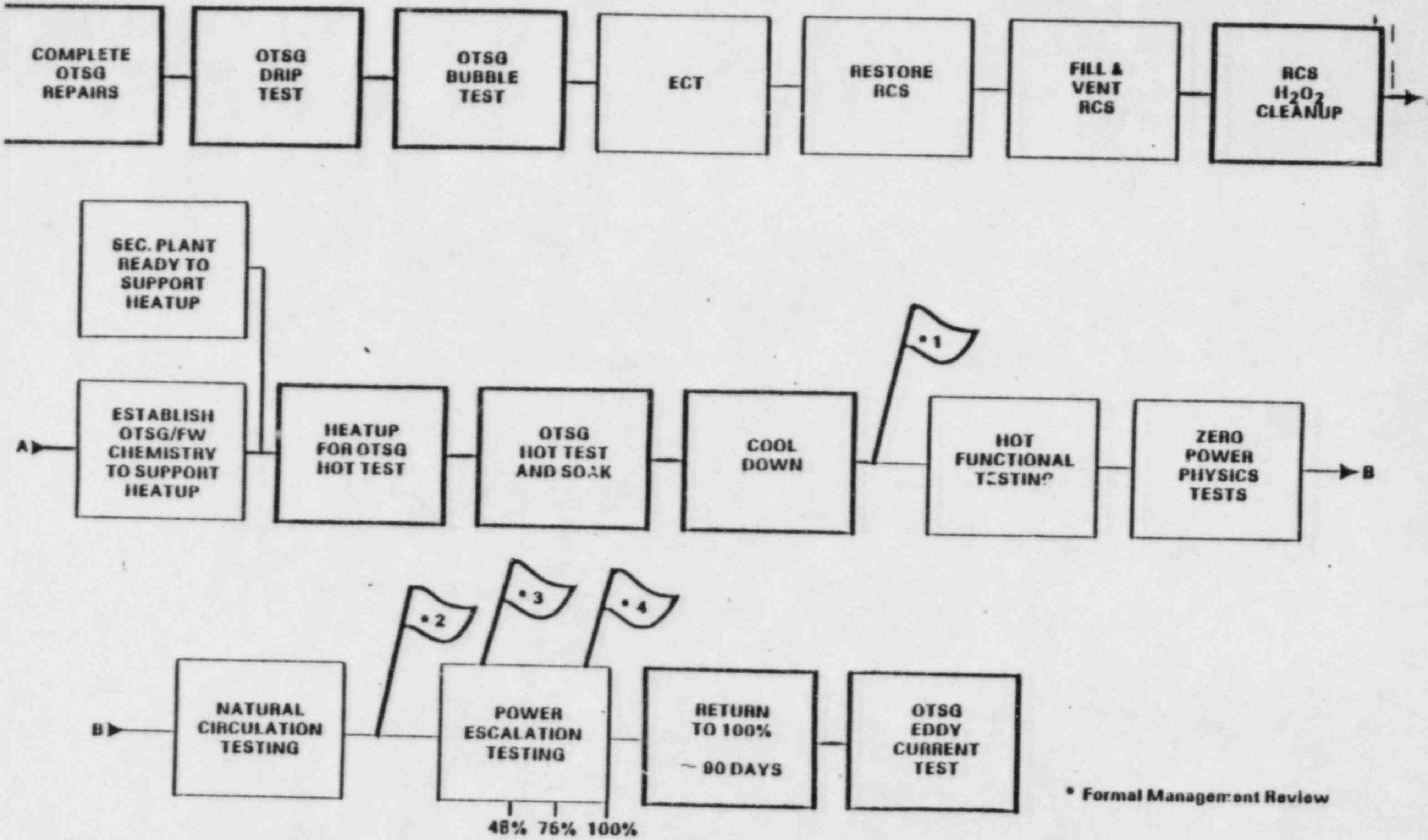
II. PRECRITICAL TESTING

Both hot and cold (pre-service) testing will be performed prior to criticality.

The overall objective for the pre-service program is to demonstrate the success of the repair by providing adequate assurance of the post-repair primary to secondary structural and leak tightness integrity of the steam generators.

FIGURE A-1

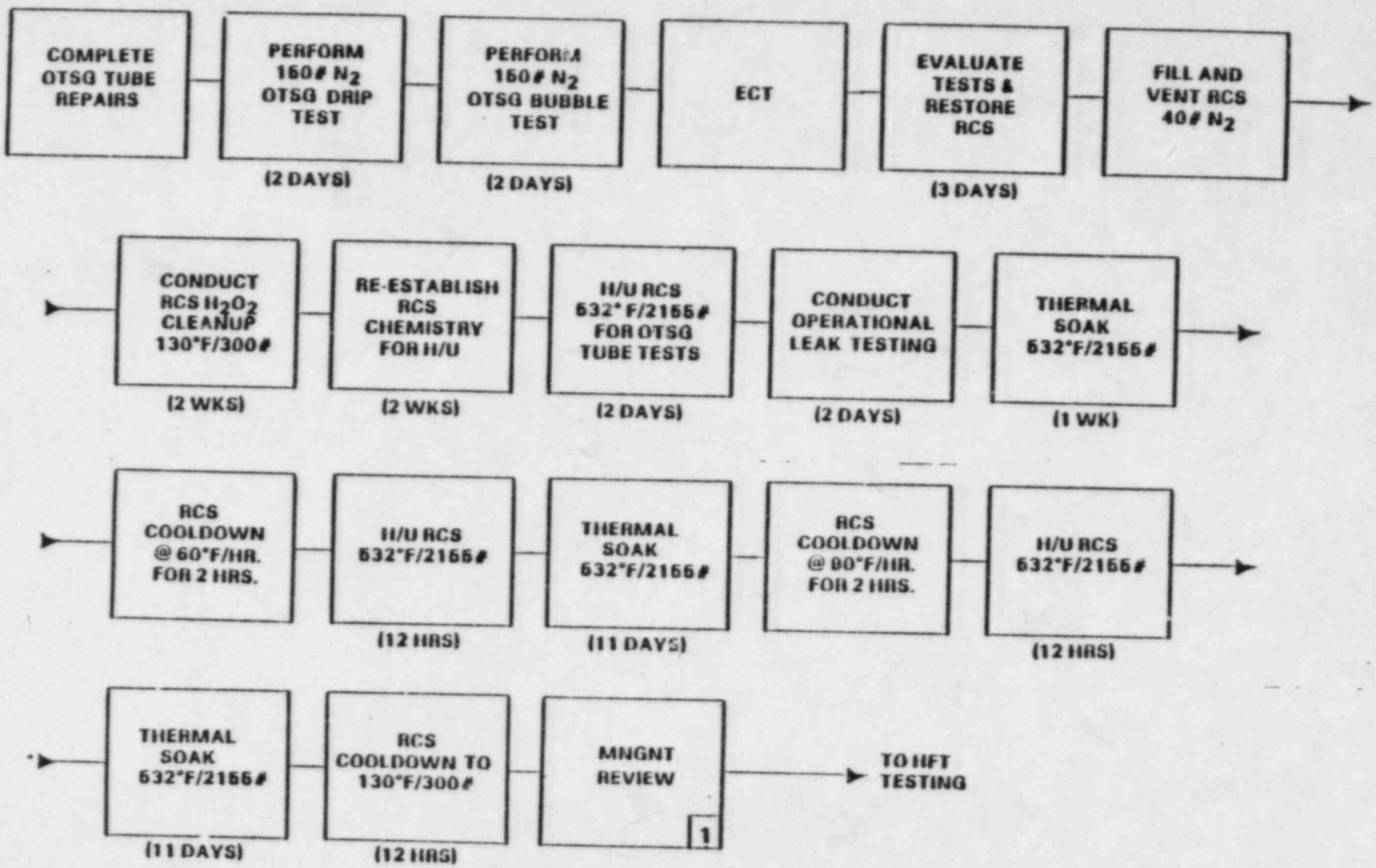
TMI-1 Restart Test Program Including OTSG Repair



* Formal Management Review

FIGURE A-2

TMI-1 OTSG Tube Repair Precritical Test Program



The specific post-repaired features of the steam generators to be tested include the tubing kinetic expansions, the Westinghouse roll plug installations, and the B&W weld plug and explosive plug installations. In addition, the testing will simulate operational loading of partial through wall defects in tubes remaining in service.

The sequence of cold and hot precritical tests is shown in Figure A-2.

A. Pre-service Test Program

1. Cold Testing

Tests conducted prior to heat up included the following:

a. <u>Drip test</u>, whereby the primary side is drained completely, the secondary side pressurized to 150 psig, and water leakage from tube ends observed in the lower head. This method leak tests plugs installed in the lower tubesheet, the tubing expansions, and the full length of tubing remaining in service.

b. <u>Bubble test</u>, whereby the primary side is drained to a few inches above the upper tubesheet, secondary side water level is lowered and pressurized to 150 psig. Kinetic tube expansions, tubing above the lowered water level, and upper tubesheet plugs are leak tested by visually observing gas bubbles in the upper head. Based on experience at similar plants, this method is expected to have a lower limit of detectability of about 0.1 gal/day per tube (leakage at normal operating pressure and temperature).

c. <u>Baseline eddy current testing</u>, to verify that the kinetic expansion has not changed the condition of tubing, and to provide a baseline for post-critical ECT. Precritical ECT is discussed in greater detail in Section III with the post-critical program.

As a result of findings in the drip, bubble, and ECT tests, some additional repairs were conducted. Following these repairs, the drip and bubble tests were repeated.
The results of the cold complete testing program are as follows:

a. <u>Initial Drip Tests</u>

To begin the cold testing program, a drip test was conducted twice in each steam generator. The first test identified 10 tubes in "A" and 21 in "B" as leaking. The second identified 6 in "A" and 5 in "B". 2 in "A" and 5 in "B" leaked in both tests. This inconsistency between the two tests is thought to be due in part to condensation in the upper head, in isolated cases to wet felt plugs held in blocked tubes, and to the difficulty and uncertainty in observation. Because drip rates were low, in

most cases less than 1 drip/min., identification of the dripping tube was difficult. The drip test is used only as an indicator of a need for further investigation. The determination of the acceptability of a tube was based on the bubble test and ECT results.

Several plugs were identified as dripping. Welded and explosive plugs were repaired or replaced. Mechanical plugs were evaluated and rerolled or replaced as necessary.

b. Initial Bubble Tests

The bubble test identified 10 tubes in "A" and 13 tubes in "B" as leakers. Of these 23 tubes, 4 tubes in "A" and 11 tubes in "B" had already been identified for further investigation by the drip test. By placing a temporary stopper in each bubbling tube at the lower face of the upper tube sheet (US+0) and at US+14, the axial location of the leak could be further identified. All of the leaks were found to come from below the top of the qualification length of the kinetic expansion joint, with the possible exception of one tube which bubbled slightly, and was not investigated further during stopper testing because the bubbling rate was too low for visual tube identification when the stoppers were placed. No joints were found to leak.

Several plugs were identified as bubbling. Welded plugs were repaired or replaced. Mechanical plugs were evaluated and rerolled or replaced as necessary.

c. Eddy Current Testing

In addition to the baseline eddy current testing, each of the tubes identified in the drip and bubble test was investigated using eddy current techniques. Using the .540 differential probe, eddy current signals have been found in the unexpanded portion of all but one bubbling tube. This particular tube (OTSG B 80/45) is the tube discussed above which bubbled slightly but was not investigated further during stopper testing. Of the 10 tubes in "A" and 10 in "B" which dripped but did not bubble, only 1 tube in "B" has a pluggable eddy current indication (greater than or equal to 40% through wall). ECT also identified an indication in one dripping tube in "A" of less than 20% through wall at UTS-10.

The 23 tubes have also been examined using the 8 x 1 absolute ECT probe. All signals are on 1 or 2 coils only, corresponding to a range of arc lengths of a minimum

sensitivity of .024 inches to approximately .413 inches. The voltage data for most 2 coil defects is not balanced for both coils, suggesting arc lengths closer to the lower end of the range than the higher. Based on this information, GPUN considers that the indications always existed but are now somewhat more visible.

GPUN has plugged or plugged and stablized the 23 bubbling or dripping tubes with ECT indication greater than or equal to 40% through wall. The tubes with less than 40% ECT indications were left in service and added to the augmented ISI list or reinspection during subsequent ECT, and will add to the data base. GPUN has evaluated the 23 pluggable ECT indications (in dripping or bubbling tubes) and determined the following:

1) All leaking defects are between UTS-02 and UTS +07.

2) Four of these defects can be discerned on previous (1982 ECT) inspection records but were missed apparently due to analyst error.

3) Fifteen of these defects have small amplitude signals which in the 1982 examination were masked by UTS noise.

4) Four of the signals are at the entry point of the upper tubesheet, and were previously masked by probe saturation on tube sheet entry signal.

In addition to the ECT described above, GPUN has conducted the post-repair pre-service eddy current examination described in Table A-1. The pre-service inspection data was obtained as a very sensitive benchmark against which to compare similar ECT inspections proposed to be obtained after 90 Full Power days. Such comparisons may provide further information confirming arrest of crack growth in an operating generator. The results of these pre-service tests are shown in Table A-2.

Table A-1
Post Repair ECT Inspection Summary

SCOPE	Pre-Service Inspection	90 F.P. Days Inspection	Cycle 6 Refueling Outage	Remarks
1(a) All tubes 40% T.W. below the qual. length in both OTSG's	(i) 0.540" S.D.H.G. Full Length (ii) 8 x 1 to confirm S.D. Ind. & circumferential extent	Repeated	Repeated	
1(b) All adjacent tubes to 10 selected plugged unstabilized tubes with defect in 15th, 10th & 1st spans (10/Ea. OTSG)	*Wear baseline exam. in area of interest. (Using ECT probe demonstrated adequate for wear examination in area near defect.)	Repeated	Repeated	*Use ECT technique proven by laboratory testing to be adequate for wear exam.
1(c) All adjacent tubes to 10 selected plugged unstabilized tubes per each OTSG in the periphery	*Examine for O.D. wear baseline in the 16th span (Using ECT probe demonstrated adequate for wear examination in area near defect.)	Repeated	Repeated	*Use ECT technique proven by laboratory testing to be adequate for wear exam.
1(d) All tubes had new indications in the 6" qual. length	8 x 1 absolute for 6" Q.L.	Repeated	Repeated	
1(e) 50 tubes in the high plugging density area per each OTSG	0.540" S.D. high gain inspection for full length	Repeated	Repeated	

Table A-1 (Cont'd)
Post Repair ECT Inspection Summary

SCOPE		Pre-Service Inspection	90 F.P. Days Inspection	Cycle 6 Refueling Outage	Remarks
1(f)	3% of tubes in addition to 1(d) in each OTSG from top of 6" qual. length to lower surface of UTS	8 x 1 examination in UTS	Repeated	TBD	
1(g)	All adjacent tubes to 5 plugged tubes per each OTSG with 3V indications in lower part of OTSG's	*Wear baseline examination at same elevation as defect indication in the plugged tube	Repeated	Repeated	*Use ECT technique proven by laboratory testing to be adequate for wear exam.
2	3% of tubes remaining in service per each OTSG in addition to above 1(a), (b), (c), (d), (e) & (g)	0.540" S.D. high gain full length inspection See Note 1.	Repeated	Repeated	

Note 1: By doing pre-service examination in above categories 1(a) & 1(e), if no new defect or no indication of defect growth from previous 0.540" high gain data, such data obtained in 1982 may be considered representing conditions after expansion. No need to perform item (2) for the preservice baseline.

Table A-2
Post Repair ECT Pre-Service Baseline Inspection Results

	Scope from Table A-1	Probe Type	Number of Tubes OTSG A	OTSG B
1.	~180 tubes/OTSG (items 1b, c, e, g) indications ≥40% TW	.540 SD	11	1
2.	All <40% TW previously identified to be left in service (item 1a)	.540 SD	1*	No change
3.	~3% of unexpanded tube within UTS below 6" joint (verified ≥ 40% TW using .540) (items 1f, d)	8 x 1	3**	0
4.	~3% of 6" joint (items 1f, d)	8 x 1	9***	21***

* On one tube the phase angle for an OD indication at TSP #6 shifted such that the previous 35% through wall indication was evaluated as 60%. The 8x1 data did not change (1 coil, 1/2 volt). The phase shift was apparently due to interference from TSP #6. GPUN evaluated this crack as unchanged, but because of the uncertainty in through wall extent, the tube will be plugged.

** The 11 indications shown in line 1 can also be detected by the 8x1 but are not included in the table twice.

*** These low voltage indications are not unanticipated since the 8x1 probe is more sensitive than the .540 probe in the upper tubesheet. Noise levels in the joint area are too high to use the .540 probe for investigation of through wall extent. These tubes were dispositioned for plugging based on bubble test results.

The tube indications in line 1, of Table A-2 (11 in "A" and one in "B") were evalated in the pre-service inspection as all greater than 40% through wall with predominantly a low voltage amplitude (equal to or less than one volt). The one indication in OTSG "B" is located axially at UTS +2 and the 11 indications in OTSG "A" are located between TSP 13 and UTS +6. These 12 indications were further examined by the 8x1 probe and were all found to be equal to or less than two coils in circumferential extent with 6 of the 12 evaluated as one coil. During 1982, every unplugged tube in each steam generator was examined using the sensitive high gain differential probe. We have examined the 1982 high gain differential probe baseline inspection result tapes and determined most of the pre-service 1983 indications are within the 1982 tape noise level but can be considered identifiable given the precise location information from the 1983 pre-service inspection results. Therefore, the post-repair pre- service ECT results are considered consistent with the 1982 record inspection, and the 1982 inspection is valid as the required Technical Specification 100% inspection. No further ECT was conducted.

In addition to the 12 tubes of greater than or equal to 40% through wall indications reported on line 1, a total of 6 tubes were called at less than 40% but at equal to or greater than 20% through wall in OTSG "A" (one evaluated at 25% TW, five at 20% TW), and one in "B" (20% TW). All of the less than 40% through wall calls are of such low voltage and such uncertainty in phase angle that we cannot now conclude with any confidence whether they represent intergranular attack or surface anomalies. We have concluded that they are not of a size to warrant plugging.

With regard to the 8x1 inspection results identified on line 3 and line 4 of the above table, these are not unanticipated since the 8x1 probe technique is more sensitive than the standard different probe in the upper tubesheet region. Prior developmental testing, conducted as part of the expansion joint qualification program and documented in Section V.D.1 did identify that tube expansion in the tubesheet (or close to the expansion region) had the potential for making small defects in the tubes more visible by ECT.

We have plugged all tubes identified on line 1 and line 3 of Table A-2 having eddy current indications from the pre-service inspection of 40% or greater even though we are not sure at this time of the accuracy of the evaluation.

This dispositioning is consistent with the technical specifications and with the plugging criteria in Section VII. After the 1982 record ECT Inspection, any indication in the 16th span will be plugged as a precautionary measure. GPUN does not plan to plug additional tubes with indications in the 16th span called as less than 40% through wall (six of seven tubes identified above) because of the uncertainty associated with interpreting such a small ECT signal. These tubes were added to the augmented ISI list for reinspection during subsequent ECT, and will add to the data base.

d. Follow-up Testing

Following repair of the residual tubes identified above, additional drip and bubble tests of both OTSG's were conducted on June 17 and June 26. These tests of OTSG "B" showed no observable leaks. The drip test on OTSG "A" identified five plugs (four rolled plugs and one explosive plug bottom tube sheet) and one tube with drops of water clinging to the end. No drops were seen to fall free over the 30 second observation period from any of these six tubes. This particular tube (unplugged) had been inspected by ECT in the previous month and dispositioned as no detectable defects. This tube was not plugged. The leakage from the plugs was extremely small and since future operation may seal the plug leakage with time, no further repair action regarding the dripping plugs was taken.

The bubble test on OTSG "A" identified seven plugs (one welded and six rolled) and three unplugged tubes from which some gas bubbles were detected by visual observation. The welded plug was repaired. This was the first bubble test on this welded plug since it had been repaired. All of the tubes and rolled plugs passing nitrogen in OTSG "A" had very fine streams of tiny bubbles which did not cause surface disturbances of the water layer. This amount of bubbling is less than that observed in previous testing. Due to the small amount of leakage, no further action was taken regarding the three tubes and six rolled plugs. The results of pre-critical hot functional OTSG testing will be used to disposition these tubes prior to critical plant operation.

Throughout the RCS cleanup, we monitored for primary to secondary leakage by examining the secondary side for activity and boron. No tritium was detected in either OTSG. Tritium was 4.4×10^{-3} uci/ml in the RCS and has a minimum detectable activity of about 5×10^{-6} uci/ml. If one assumed equal mixing in the OTSG secondary

side, the leak, if any, at 300 psi differential pressure was less than 1.1×10^{-3} gpm in each generator, based on no detectable tritium. Similarly, boron in the secondary was undetectable, confirming that the leak, if any was less than 3.1×10^{-3} gpm in each generator. There were several Cesium-137 measurements above the minimum detectable activity of 1×10^{-7} uci/ml. Since Cesium-137 was 1.6×10^{-3} uci/ml in the RCS, they correspond to a primary to secondary leak rate of equal to or less than 1.4×10^{-4} gpm in OTSG A and 1.9×10^{-4} gpm in OTSG B.

Our overall evaluation of the post repair inspection results, including the pre-service inspection baseline ECT testing, is as follows:

1. With the possible exception of four tubes, we have identified no kinetic expansion joints which leak nitrogen from above the 6" qualifiction length at 150 psi delta P.

2. Existence of small arc length 100% through wall defects found by bubble testing is consistent with discussion in Section IX.

3. Existence of small arc length partial through wall defects found by ECT is consistent with discussion in Section IX.

4. 8x1 ECT probe results from within the tubesheet region are consistent with prior developmental results and are as expected.

5. The total evidence available continues to support a conclusion that cracks are not growing and that new cracks are not occurring.

2. Hot Testing

The sequence of tests to be performed during the steam generator hot testing period is discussed below. Conventional leakage monitoring techniques planned for post-critical operations (Section X) would not be effective during this test period. The very low concentration of fission products in the RCS after a 4 year outage are insufficient to provide a measurable indication on a continous basis for the leak rates to be detected. Therefore a tracer will be used in the primary system. Use of the Kr-85 as a tracer has been evaluated in a separate safety evaluation (Ref. 65). The hot testing leakage monitoring program is summarized in Table A-3.

When the steam generator hot functional test sequence is complete, a management review of the results will be conducted. If the results are satisfactory, the plant will proceed with the normal precritical hot functional program, and subsequently with critical operation. The test sequence is as follows:

a. Normal Heatup

The RCS temperature and pressure will be raised to 532°F and 2155# in accordance with normal operating procedure.

Table A-3

Hot Testing Leakage Monitoring

Parameter	Sample Location	Frequency[6]	Sensitivity
Krypton-85	RMA-5L (offgas monitor)	Continuous[1]	0.18 ± 0.05 GPH[5]
	RMA-5L (grab sample)	4 Hours (steady state) 1 Hour (cool-downs)	1 ± .4 GPH[5]
Boron	OTSG	Daily	1.6 GPH[2]
Tritium	OTSG and Hotwell	Daily	11 GPH[3]
Gamma Isotopic Analysis	OTSG and Hotwell	Daily	[4]
	RMA-5L (Grab sample)	1 Hour (Cooldowns)	[4]
	RMA-5L (Grab sample)	4 Hour (Steady State)	[4]
	RMA-5L (Grab sample)	2 gph increase calculated from RMA-5L readings	[4]

Notes:

[1] Counts/minute to be recorded on a strip chart or logged every 15 minutes during cooldown and every 30 minutes during steady state.

[2] Assumes all Boron equally mixed in OTSG secondary side water and 24 hours of constant leakrate.

[3] Assumes Tritium equally mixed in hotwell, condensate, feed and OTSG. Based on 24 hours of constant leakrate.

[4] Sensitivity to be determined during testing. RCS cleanup has reduced many isotopes in RCS to less than or barely detectable levels (including Cesium-137).

[5] Assumes 20 cfm discharge flow from vacuum pumps and 4.5×10^{-2} uci/cc Kr-85. Some additional uncertainty in sensitivity expected would be due to gas flow variation in vacuum pumps or a lower Kr-85 concentration.

[6] Frequencies subject to change based on engineering evaluation of the data during leak rate testing.

b. <u>Operational Leak Test</u>

This test is required by technical specifications whenever work has been performed in the reactor coolant system. The pressure in the primary system will be raised to approximately 2285#, creating a differential pressure between the primary and secondary of approximately 1400# (maximum normal operating differential pressure). This is expected to be the maximum differential pressure experienced by the repaired tubes.

c. <u>First Thermal Soak</u>

Conditions will be allowed to equilibrate at 532°F and 2155# for approximately one week, to provide baseline leakage data and to allow monitoring of leakage for trends.

d. <u>Normal Cooldown Transient</u>

A controlled cooldown will be conducted according to normal procedure, at approximately 60°F/hr for approximately three hours to 350°F. Tube to shell delta T will be maintained at less than 70°F to limit the stresses placed on the tube. Leakage will be monitored throughout the transient.

e. <u>Second Thermal Soak</u>

The RCS temperature and pressure will be returned to 532°F and 2155#, and held there for eleven days. Leakage data will be obtained for comparison with the earlier thermal soak, and to monitor for developing trends.

f. <u>Accelerated Cooldown</u>

A controlled cooldown will be conducted at close to the maximum rate permitted by technical specifications, at approximately 90°F/hr for approximately two hours. This transient is expected to apply greater loads to the repaired tubes than the earlier cooldown. Tube to shell delta T will be monitored to determine stresses but will be permitted to increase as high as 140°F. Leakage will be monitored throughout the transient.

g. <u>Third Thermal Soak</u>

The RCS temperature and pressure will be returned to 532°F and 2155#, and held there for approximately eleven days. Leakage data will be obtained for comparison with the earlier thermal soaks, and to monitor for trending.

h. Normal Plant Cooldown

The plant will be cooled down to 130°F using the tube rupture procedure for training purposes. During this cooldown tube to shell delta T will be limited to 70°F, and fuel pin compression limits will be observed. The plant will be maintained at 300#, 130°F pending management review of the OTSG hot functional results.

i. Flow Rate Testing

Because tubes were plugged during the repair process, the RCS flow rate must be measured after repair to verify compliance with technical specification. This test will be performed when the plant is at normal operating temperature and pressure.

III. POST-CRITICAL PLANT TESTING

The deliberate, methodical approach to testing will be maintained throughout the power ascension program. The normal program has been lengthened to permit ample time for leakage monitoring and trending, as well as for familiarization with plant performance following the modification. After the power escalation program is complete, and again at the next refueling outage, special inservice inspection programs will be conducted to look for the effects of operation after the repair on tubing and components.

A. Power Escalation Testing

Power escalation testing is expected to serve two purposes in testing the steam generators. First, the slow progression from power level to power level will permit monitoring of possibly changing plant conditions such as leakage. Second, several of the tests already planned for start-up testing will apply loads to the steam generator tubes. Leakage monitoring before and after the transients will provide information on the condition of joints and tubing.

The power escalation program is discussed chronologically below. Transient tests of interest are noted for each power level.

1. Lower Power Testing

Following hot functional testing and initial criticality, the normal plant zero power test will be conducted. After this approximately one week program, low power natural circulation testing will be performed.

This test verifies the tuning of the Integrated Control System (ICS) to maintain preset OTSG levels under loss of main feedwater and natural circulation conditions. It also verifies proper response of the EFW system as well as the establishment and maintenance of natural circulation under varying conditions. Testing will be conducted at approximately 3% of rated thermal power to simulate the decay heat load that would correspond to significant core burnup. EFW initiation is expected to stress the OTSG tubes. This test will also verify that plugged tubes have no effect on establishing natural circulation flow.

A management review will be conducted following natural circulation testing. Satisfactory OTSG and plant performance will be necessary to increase power.

2. Operation at Less Than 50% Power

Power escalation testing will be conducted for several days each at 15%, 25%, and 40-48% power. The 40-48% plateau testing will include a loss of feedwater test. At a power level of approximately 40-48%, both main feedwater pumps will be tripped. All three emergency feedwater pumps will start automatically and OTSG level will be controlled at approximately 30 inches by emergency feedwater. The use of EFW will cool and stress the OTSG tubes.

The RCS Overcooling Control test will demonstrate that the control room operator can properly throttle EFW flow to prevent overcooling of the RCS following a loss of RCP's with OTSG level initially at 30" on the startup range.

The effects of this transient and of operation to date will be monitored during a one month soak at approximately 48% power. The power level was selected as the minimum permitting two main feed pump operation. Some operator training will also be conducted during the soak. Prior to increasing power, another management review will be held to evaluate test results and plant performance during the soak.

3. Power Escalation to 100% Power

Testing at 75% and 100% power will conclude the power escalation program. The 75% plateau will include approximately five days of testing followed by another one month soak to observe plant performance. Power will then be increased to 100% power for approximately one week of testing. Testing of interest at this plateau include the 100% turbine-generator trip.

A management review of plant performance will then be conducted before the plant procedes with normal power operation.

B. Eddy Current Testing

Either 90 calendar days after reaching full power, or 120 calendar days after exceeding 50% power, the plant will be shutdown for the performance of eddy current testing. Test results will be compared with a baseline taken prior to restart to verify the lack of defect propagation during normal operation. The baseline, 90 day, and next refueling ECT examinations are discussed in detail in Reference 56 and summarized in Table A-1. Testing listed for the preservice baseline wase performed after repairs were complete to provide evidence that no changes have occurred since the 1982 100% record inspection. Results are discussed in Appendix A.II.A. Any new or changed ECT indications found in the subsequent inspections will be evaluated. If evaluation shows they are unacceptable, they will be treated as new defects with subsequent actions taken as required by Technical Specifications.

C. Steam Fittings ISI Program

GPUNC will inspect the main steam line fittings at TMI-I for potential water droplet erosion. The following criteria were used (in descending order of erosion probability) to select monitoring data points.

1 - Fittings close or adjacent to the OTSG
2 - Fittings of 90° configuration
3 - Fittings from the "A" steam generator

Since there are more tubes plugged in the "A" OTSG than the "B", the "A" steam lines may have a higher probability of erosion. Therefore, inspections will be made of steam lines from the A OTSG. Based on the above the following fittings were inspected before start-up and will be reinspected at the next refueling outage following restart.

Table A-4

Steam Line Fittings Inspection

"A" OTSG

Item	Qty.	Description
1	2	First 45° Ells after OTSG exit

This inspection will be done using ultrasonic testing techniques for measuring pipe (fitting) wall thickness according to an adaptation of ASTM E 797-81 "Standard Practice for Measuring Thickness by Manual Ultrasonic Pulse - Echo Contact Method." The ultrasonic data density (number of data points) of the pipe wall surface will correspond closely to that already done on the turbine extraction piping at TMI-I.

Future inspection frequency and scope will be determined after the results of the next refueling outage's inspection have been evaluated.

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

Docket No.: 50-289

MAY 1 0 1983

MEMORANDUM FOR: Gus C. Lainas, Assistant Director
for Operating Reactors, DL

FROM: Daniel R. Muller, Assistant Director
for Radiation Protection, DSI

SUBJECT: SAFETY EVALUATION REPORT INPUT FOR RETURN TO SERVICE
OF TMI-1 STEAM GENERATORS (TAC #47484)

PLANT NAME: Three Mile Island Unit 1
LICENSING STAGE: OR
DOCKET NUMBER: 50-289
RESPONSIBLE BRANCH: ORB#4; J. VanVliet, PM
REQUESTED COMPLETION DATE: May 9, 1983
DESCRIPTION OF RESPONSE: SER Input For Return to Service of TMI-1's OTSG
REVIEW STATUS: Complete

The Radiation Protection Section of the Radiological Assessment Branch has completed its review of TMI-1's plant safety assessment for return to service after the OTSG repair. Although the final dose estimates for the OTSG repair project are much higher than the original estimates, they are still within an acceptable range. The increase in onsite annual exposure due to the OTSG repairs is expected to be minimal.

This review was performed by C. Hinson, RPS, RAB.

Daniel R. Muller

Daniel R. Muller, Assistant Director
for Radiation Protection
Division of Systems Integration

Enclosure
SER Input For Return to
Service of TMI-1

cc: w/enclosure
R. Mattson
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Our initial Safety Evaluation Report input (October 13, 1982 letter from Stolz, NRC to Hukill, GPU) for the TMI-1 OTSG Repair was submitted during the early stages of the OTSG repair program. At that time, GPU's person-rem exposure estimates for each task were based on time and motion studies done in an actual OTSG at B&W's test facility at Mt. Vernon, Indiana. These estimates included only those items in the steam generator program identified as part of the kinetic expansion repair. GPU's estimate for these tasks totalled 268 person-rems. During the course of tube expansion, several problem areas were discovered which resulted in a greater amount of time spent inside the OTSGs. GPU's current estimate for exposure due to kinetic expansion alone is 586 person-rems. This is more than double their original estimate of 268 person-rems.

Several problem areas, including equipment malfunction, contributed to this increased exposure. Video camera problems during tube expansion blasting resulted in having to remove the camera prior to each blast and then reinstall it prior to each personnel entry. Although this resulted in increased personnel exposure, it was more person-rem efficient than performing corrective maintenance on the camera inside the generator. Mechanical problems with the debris removal device resulted in much higher exposures than originally estimated during the first pass debris removal. The licensee redesigned this device prior to the second pass debris removal, and the resulting doses were reduced significantly from those experienced on the first pass. The procedure of precoating the generator tubes after the expansion inserts were in place resulted in an unacceptably high misfire rate due to seepage of the liquid precoat into the inserts. Inserting the inserts after the precoat was applied reduced the number of misfires (and therefore the time spent in the generator required to identify and replace misfired inserts), but resulted in higher exposures because two

generator entries were required for each firing. Another problem encountered was misfire jump out. The force of the insert detonations caused the detonating cords to pull some of the misfired inserts out of the OTSG tubes. The time spent in locating the unexpanded tubes from the misfires resulted in additional exposure. During the second pass expansion, misfire jump outs were prevented by using hold-down devices and additional care in moving about the head area. These changes resulted in some increase in the time spent in the generator. The actual time involved in removing debris from the generator following each detonation turned out to be much longer than originally planned for. This, too, resulted in additional unplanned exposure.

Although these unexpected problems resulted in a higher overall exposure than originally estimated for the kinetic expansion process, the licensee incorporated ALARA techniques in resolving these problems. The licensee monitored and documented all generator entries to minimize exposures and measure worker efficiency. The licensee also minimized exposure for the performance of corrective maintenance. Where equipment redesign was necessary, the licensee incorporated lessons learned about equipment reliability into the equipment redesign to minimize equipment downtime and thereby minimize exposure. All workers received training in the job to be performed prior to actual steam generator entry. Prior to initiation of the kinetic tube expansion, the steam generator heads were flushed and shielded to reduce worker exposure. Additional ALARA practices used by the licensee during the OTSG repair were described in our previous Safety Evaluation Report (October 13, 1983).

In addition to the 586 person-rems expended for the kinetic expansion process, the licensee will expend approximately 697 person-rems for other portions of the program such as preparatory work, tube plugging, end milling, clean-up, and testing. Approximately 331 tubes were plugged before the magnitude of the tube cracking problem was discovered and it was decided to repair the tubes using the kinetic expansion process. Approximately 814 additional tubes are being plugged or stabilized as part of the OTSG program. Tube plugging and stabilization will account for approximately two-thirds of the non-kinetic expansion exposure. The balance of this exposure will be due to RCS inspection, eddy current testing, end milling, clean-up, and testing.

The total estimated exposure for the OTSG repair is 1283 person-rems. Additional plugging may result in a slightly higher total for the job. The licensee has performed all steam generator work in accordance with ALARA guidelines and all required radiation protection practices. They have incorporated the ALARA guidance provided in Regulatory Guide 8.8, Rev. 3, "Information Relevant to Ensuring That Occupational Exposures At Nuclear Power Stations Will Be As Low As Is Reasonably Achievable", and have maintained individual radiation doses within the limits of 10 CFR Part 20. Although the licensee's final exposure estimate for the expansion process is more than double their original estimate, the final estimate of 1283 man-rems for the entire OTSG repair is comparable to exposures from steam generator repairs at other facilities. Based on the above, the staff finds the occupational dose control aspects of the OTSG repair project, and the final exposure for the project acceptable.

The licensee has taken several steps to prevent future chemical contamination of the OTSGs and the RCS. These include removal of the sodium thiosulfate tank and implementation of administrative controls to prevent direct injection of contaminants into the RCS. Primary to secondary leakage is not expected to occur following the OTSG repair, but if this does occur, it is expected to increase the annual exposure at TMI-1 by less than 1%. This increase is small and is acceptable.