Supplemental Safety Evaluation

Metropolitan Edison Company
Jersey Central Power and Light Company
Pennsylvania Electric Company
GPU Nuclear Corporation
Three Mile Island Nuclear Station, Unit No. 1
Docket No. 50-289

BACKGROUND

On September 14, 1983 and October 25, 1983, the licensee provided Rev. 3 to Topical Report 008 and the OTSG precritical non-nuclear hot functional test results (TDR-488). By letter dated September 30, 1983, the licensee also provided comments on our SER (NUREG-1019).

2. DESCRIPTION OF REPAIR METHOD

Evaluation

In the SER, we provided a description of the repair method which focused on the 22-inch kinetic expansions which are limiting in determining that tube pullout from the tubesheet cannot occur under design basis accident conditions as a consequence of severance of the tubes at the tube repair transition zone. By letter dated September 30, 1983, the licensee noted that our SER did not clearly indicate that tubes were repaired using both 22-inch and 17-inch kinetic expansions. We agree with the licensee's comments.

The majority of tubes were repaired using a 17-inch expansion because the vast majority of defects were located near the top of the upper tubesheet. The 17-inch expansions provided for repair of tubes with defects down to 11 inches from the top of the tubesheet while retaining the 6-inch qualification zone. Tubes with defects between 11 inches and 16 inches were repaired using 22-inch expansions. Because the 22-inch expansion, which is the limiting case, was already addressed, the information does not alter the conclusions in our SER.

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This section should now read:

"The repair method utilizes a kinetic expansion process to form the tube against the tubesheet; i.e., close the 8-mil radial gap. The kinetic expansion process closes the 8-mil gap and produces an interference fit between the tube OD and tubesheet drilled holes ID to achieve a leak-tight, load-carrying joint. The tube repair procedure requires that all repaired tubes have a 2-inch defect-free unexpanded section within the UTS above the secondary side tubesheet surface. This unexpanded section will prevent tube pullout in the event a tube is severed at the repair transition zone. Developmental testing has been conducted to demonstrate that a kinetically expanded 6-inch long defect-free section of tube (qualification zone) can provide the necessary leak-tightness and load-carrying capabilities required for operation. Therefore, all tubes which have defects down to a depth of 16 inches into the tubesheet can be repaired. The 16-inch section plus the 2-inch unexpanded zone and the 6-inch qualification zone account for the full depth of the 24-inch thick tubesheet. The vast majority of tubes have defects in the upper 11 inches of the tubesheet and will be repaired using 17-inch kinetic expansions which allows for retention of the 6-inch qualification zone. The forming technique consists of inserting a polypropylene sheath into each tube. The polypropylene sheath contains a detonation cord which, when ignited, forces the polypropylene sheath against the tube. The resultant force expands the tube. The polypropylene sheath and detonation cord assembly is called a candle. The candles are detonated by a blasting cap which is maintained outside the steam generator in a sealed container and ignited electrically by a licensed blaster. The two OTSG's have a total of approximately 31,000 tubes, all of which have been expanded, except those previously plugged. After all tubes were expanded, those tubes which contained non-repairable defects were plugged."

3.1 Determination of Causative Agent(s)

In the SER, we stated that "The thiosulfate tanks have also been physically removed." By letter dated September 30, 1983, the licensee pointed out that the lines which connects the thiosulfate tank to the reactor coolant system have been physically severed and sealed but the tank has not been removed. This information does not alter our conclusion in the SER.

The paragraph should now read:

> "The staff consultant (NUREG-1019, Attachment 3) expressed concern about an inconsistency on pages 13-14 of the licensee's Topical Report 008, Rev. 2. The licensee stated that sulfur reduction might have occurred during the hot functional test, and that the subsequent OTSG tube degradation was as a consequence of reduced sulfur species. In the Test Section of the same report, laboratory data indicate that cracking of sensitized type 304 Stainless Steel (SS) and Inconel 600 specimens in low temperature, oxygenated water contaminated with thiosulfate proceeds without the presence of other reducing agents. The consultant's concern is that in one case reduced sulfur species is suggested as the corrosion initiator, while in the other case it is shown that corrosion will occur in the absence of reduced species. We are of the opinion that irrespective of the exact scenarios, the thiosulfate contaminant has been removed from the system. The lines connected to the thiosulfate tank have been physically severed and sealed. The intermediate states which may have contributed to the degradation of the components are not germane to the staff's final conclusion that at TMI-1 thiosulfate contamination combined with the presence of oxygen was the main cause of the OTSG tube degradation."

3.2 Examination and Repair of the Remainder of the RCS

In the SER, we stated that "all corrosion-affected sections in the waste gas system have been replaced." By letter dated September 30, 1983, the licensee noted that only sections of the waste gas system with unacceptable corrosion have been replaced. Piping with minor corrosion indications will be placed on an augmented inspection list. We agree with the licensee, because sections in which the corrosion indications were insignificant need not be replaced.

This section and the conclusion should now read:

"During a supplemental examination of systems which interface with the reactor coolant system, evidence of sulfur-induced corrosion was found in a waste gas system stainless steel line. The extent of corrosion was quantified and all sections with identified cracks have been replaced. One valve in the waste gas system exhibited an indication which could not be identified as a defect. This valve has been placed on the in-service inspection list for further monitoring. In addition, the power operated relief valve (PORV) was removed for examination. Components of the PORV were found to exhibit pitting corrosion attributable to sulfur which could have reduced the valve's capability to function but did not affect its structural integrity. At a meeting on May 20, 1983, the licensee provided results of the pressurizer corrosion examination. Examination of the PORV block valve, the connecting piping, safety relief valves, and the remainder of the pressurizer revealed only shallow pitting on a non-seating surface of one of the two safety relief valves. Based on this examination, the PORV was rebuilt with uncorroded parts and both safety relief valves were replaced.

<u>Conclusion</u>

The staff finds that the PORV was replaced with a refurbished valve. Additionally, the staff notes that, although some light pitting was found on one of the two safety valves, the pitting was on a nonseating surface and neither valve body had to be replaced because of corrosion. Also, affected portions of the waste gas system were replaced where necessary. The remainder of the reactor coolant system and interfacing systems which were inspected, within the limitations of the inspection method employed, disclosed no defects attributable to sulfur-induced corrosion. Therefore, based on the above, the staff finds that GDC 1, 14, 15 and 31 have been met, and that reasonable assurance exists that the public health and safety is protected."

3.3 OTSG Examinations to Determine Extent of Degradation

In the SER, we summarized in Table 3.3-1 an extended post-repair eddy current inspection plan and imposed a license condition for monitoring and plant shutdown if primary to secondary leakage increased significantly. By Topical Report 008, Rev. 3 and letter dated September 30, 1983, the licensee indicated that the post-repair baseline eddy current inspection has been completed according to Table 3.3-1 in the SER. However, the number of tubes tested in each category vary slightly, because Table 3.3-1 was intended to provide approximate numbers. The results of the post repair inspection were consistent with the 100 percent inspection record in 1982. Additionally, the licensee stated that primary-to-secondary leakage monitoring has been conducted and that a leakage rate of 0.1 gpm above baseline is detectable. The information provided does not alter our conclusion that the post-repair extended inservice inspection program is acceptable. However, the license conditions need to be revised to reflect the new information.

This section should now read:

"The post-repair baseline eddy curent inspection described in Table 3.3-1 was completed both in scope and methodology. The results of the post-repair baseline eddy current inspections were found to be consistent with the 100 percent inspection record of 1982. While some tubes were plugged as a preventive measure as a result of the baseline inspection, it is generally concluded that small arc length partial through-wall cracks existing in the tubing are not growing nor are new cracks occurring.

The 66 tubes left in service with less than 40% through-wall degradation, which is consistent with the Technical Specification plugging limit, were also re-examined as part of the post-repair baseline eddy current inspections. One tube was plugged based on a shift in the phase angle of the OD indication which was now interpreted as exceeding 40%, whereas previously it was evaluated at 35%.

Based on these results we find that the licensee has conducted the post-repair ECT baseline examinations in accordance with their proposed program. We agree with the licensee that with both the post-repair ECT baseline data and the 100 percent inspection record of 1982, there is now an adequate basis for evaluating any new or changed ECT indications found in subsequent inspections.

Conclusions

Based on the above evaluation, the staff concludes that the eddy-current techniques developed and qualified for inspection of the OTSG tubing demonstrated the ability to reliably detect and size, with a high degree of sensitivity, the defects that were present in the tubing. The 100% tube inspection using these techniques, tube repair, and preventive tube plugging and staking of critical defective tubes give reasonable assurance that defective tubes have been identified and repaired or removed from service.

As discussed above, the staff further finds the post-repair extended ISI program instituted by the licensee acceptable. However, to ensure that the potential for primary-to-secondary leakage remains acceptably low, the following actions, which the licensee has stated are to be implemented, will be required by license conditions: (1) the licensee shall conduct extended post-repair eddy current examinations, essentially consistent with the inspection plan defined in Table 3.3-1, either 90 calendar days after reaching full power, or 120 calendar days after exceeding 50% power operation whichever comes first and (2) the licensee shall confirm as early as feasible in post-critical operation, the baseline primary-to-secondary leakage rate. If leakage exceeds the baseline leakage rate by more than 0.1 gpm, the plant shall be shutdown and leak tested. If any increased leakage above baseline is due to defects in the tube free span, the leaking tube(s) shall be removed from service. Upon restart after removing leaking tubes from service, the baseline leakage shall be reestablished, provided that the present technical specification limit of 1.0 gpm is not exceeded."

3.4.1.b. Thermal and Pressure Cycle Loading

In the SER, we stated that 5 years of design basis thermal cycling and transient testing has been completed to demonstrate that the repaired joint will maintain it's load-carrying and leak-tight capabilities. By Rev. 3 of Topical Report 008 and letter dated September 30, 1983, the licensee provided additional information pertaining to completion of 15 years of life-cycle testing. Evaluation of the 15-year life-cycle testing is included in Section 3.4.2 of this evaluation.

3.4.1.c. Tube Preload

In the SER, we stated that the tensile preload on tubes should not be altered so that the tubes would be under compression when cold. This assures that compressive loads during operation and vibrational characteristics of the tube will remain unchanged. By letter dated September 30, 1983, the licensee commented on our evaluation. Our evaluation of tube preload is included in Section 3.4.2.d of this evaluation.

3.4.2 Mechanical Tests to Qualify the Repair Process

In the SER, we stated that 5 years of design basis thermal cycling and transient testing has been completed to demonstrate that the repaired joint will maintain its load-carrying and leak-tight capabilities, and that extended life-cycle qualification testing is in progress to confirm the continued acceptance of the repaired joint for time periods in excess of five years. By Rev. 3 of Topical Report 008 and letter dated September 30, 1983, the licensee provided additional information pertaining to completion of 15 years of life-cycle testing.

The leakage rate on test blocks after 15-years of design basis thermal and load cycling varied between 3.1×10^{-5} and 6.8×10^{-5} lbm/hr/tube as compared to a maximum value of 12.15×10^{-5} lbm/hr/tube for the 5-year design basis cycling. Because the leakage rates at 15 years of design basis thermal and load cycling are comparable to those at 5 years, this information does not alter the conclusion in our SER that the kinetically expanded joint is within the original licensing basis for the plant. The conclusion section and the licensee condition need to be changed to reflect completion of 15 years of design basis thermal and load cycling.

Section 3.4.2 should now read:

"As reported in Topical Report 008, Rev. 3, the licensee performed a series of mechanical tests to qualify the kinetic expansion process and qualify the joint to meet the design goals of load-carrying capability, leak-tightness, residual stress and tube preload variations. The primary vehicle for these tests was a series of test blocks which were fabricated utilizing archive tubesheet sections and either archive tubes or actual tubes removed from TMI-OTSG. The test blocks were then assembled and the tubes kinetically expanded using the same process as in the actual OTSG. The test block program incorporated a thermal/pressure life-cycle test which demonstrated the structural and leak-tight integrity of the expanded joint for 15 years of design basis heat up and cooldown cycles. Similar tests were performed by the staff consultant (NUREG-1019, Attachment 1) to provide an independent confirmation of the test results. The test blocks are designed and tested to ensure applicability of results to the actual steam generators. In addition, the licensee conducted tests on a full size steam generator at B&W's Mt. Vernon facility. A detailed description of the testing program by the licensee is provided in Reference 6 of NUREG-1019. During OTSG operations actual primary-to-secondary leakage of the repaired joints will be closely monitored to confirm the results of the 5-year and 15-year test program."

Section 3.4.2; Conclusion No. 1 should now read:

"The kinetic joint meets the qualification requirements in terms of load-carrying capability, tube preload and residual stresses. Leakage of the laboratory test blocks, while somewhat exceeding the licensee's qualification goal, is well within the plant Technical Specifications limit of 1.0 gpm and is acceptable. Nitrogen pressure testing of the repaired OTSG has shown fewer leaking tubes than was anticipated based on the laboratory test blocks. The structural and leak-tight integrity of the expanded joint has been demonstrated for at least a 15-year period. Primary-to-secondary leakage of the repaired joints will be closely monitored to confirm the results of the test program. Thus, the structural requirements for the joint are satisfied for operating, transient, and design basis accident conditions; leakage is well within Technical Specification limits; and thermal/pressure cycle capability has been demonstrated for operation. Therefore, the kinetically expanded joint is within the original licensing basis for the plant."

Section 3.4.2; License Condition should now read:

"The staff will condition the license to require an evaluation of operational data on leakage past the repaired joint 10 calendar years after restart, to determine if additional laboratory design basis thermal and load cycle testing is necessary to ensure continued intergrity of the repaired joints."

3.4.2.d Effects of the Kinetic Expansion on the Tubes

In the SER, we stated that 1,025 pounds of compressive force is necessary to cause tube bowing. By letter dated September 30, 1983, the licensee indicated that tube bowing begins at approximately 800 lbs, but loads must reach 1,025 lbs before the lateral displacement of the tube exceeds the nominal space between tubes. This information does not alter the conclusions in our SER because our concern is relative to tube buckling which does not occur.

This paragraph should now read:

"The licensee has recently indicated that during the kinetic expansion process, an estimated 600 tubes lost pre-tension due to slight downward movement of as yet unexpanded tubes which had corrosion-caused full circumferential cracks. For tubes which have lost pre-tension, this would result in a maximum cold compressive load of 16 lbs. Although this deviates from the licensee's repair goal, it is insignificant compared to the 800 lbs necessary to cause initiation of tube bowing and 1,025 lbs necessary before the lateral displacement of the tube would result in contact with adjacent tubes. Therefore, there is reasonable assurance that the repaired tubes are not in significant compression while cold and will not buckle during heatup when maximum compressive stresses exist in the tubing."

In the SER, we stated that cracks which are below the threshold of detectability by eddy current testing will not mechanically propagate to failure and that through-wall defects which may develop can be readily detected by primary-to-secondary leakage before the crack reaches a critical size for propagation. This statement was based on the assumption that, as fabricated, all OTSG tubes are under pre-tension. By Rev. 3 of Topical Report 008, the licensee provided new information on some tubes which had lost pre-tension prior to being repaired. The staff and our consultant (SSER Attachment 1) have evaluated the new information and determined that the loss of pre-tension will not significantly alter the vibrational characteristics of the tubes nor reduce the capability to detect through-wall cracks by primary-to-secondary leakage because the change in total tube tension is small. Therefore, this information does not alter the conclusion in our SER.

In the SER, we also stated that 1.0 ksi $in^{1/2}$ was used for the threshold stress intensity factor (ΔK_{th}). By letter dated September 30, 1983, the licensee indicated that the 1.0 ksi $in^{1/2}$ had been incorrectly stated in the SER and that 4.0 ksi $in^{1/2}$ and not 1.0 ksi $in^{1/2}$ was used for the threshold stress intensity factor. The licensee stated that 4.0 ksi $in^{1/2}$ stress intensity threshold factor is based on empirical data for Alloy-600 and thus is directly applicable. We agree with the licensee that an empirical stress intensity factor of 4.0 ksi $in^{1/2}$ for Alloy-600 is applicable. Therefore, this information does not alter the conclusions in our SER.

Section 3.4.2.d should now read:

> "The effect of high cycle flow-induced vibration loading on the repaired steam generator tubes has been evaluated by the licensee. The steady axial and high cycle bending loads define the tube loading. A linear-elastic fracture mechanics (LEFM) Code "BIGIF" developed by the Electric Power Research Institute has been used to determine when a crack of a given initial size can be expected to propagate through-wall. We find that this code is applicable because in a high-cycle flow-induced vibration loading condition experienced by the tubes in the OTSG's, the stresses are significantly below the 0.2% proof stress and well within the elastic limit of Alloy-600 tubing. Therefore, we agree with the licensee's use of

the linear elastic fracture mechanics (LEFM) Code "BIGIF" developed by the EPRI to determine when a crack of a given initial size can be expected to propagate through-wall. A key parameter in this analysis is the stress intensity factor which quantifies the interaction of crack size, shape, boundary geometry and stress field. The stress intensity factor calculation includes the loading due to internal pressure, and axial and bending loads which would tend to open up a crack during flow-induced vibration (FIV). During steady-state operation, the steam generator shell to tube temperature difference could cause an axial tension of up to 500 lbs on a single tube.

In the analysis, the load cycle imposed on the tubes included mechanical and thermal factors. Low cycle, long duration loads were combined with high cycle flow-induced vibration loading. The vibrational load amplitude was selected to be the maximum tube displacement seen under steady-state loading. The maximum tension excursion, represented by the 100°F/hour cooldown, which results in an axial load of 1107 lbs, was combined with high cycle loading.

A modified Paris equation was incorporated in the Code "BIGIF" with the feature that if the stress intensity factor range did not exceed threshold, no growth would occur. In the analysis, 4.0 ksi $in^{\frac{1}{2}}$, a value based on empirical data for Alloy-600, was used for the threshold stress intensity factor (ΔK_{th}), the value below which a crack will not propagate. The result of this analysis indicates that ECT is capable of detecting crack sizes which are smaller than those that can propagate by mechanical cyclic stress. Therefore, cracks which are large enough to propagate to failure can be detected and removed from service (SSER Attachment No. 1).

The licensee performed additional calculations to determine the maximum crack size that would remain stable under loads experienced during a main steam line break (MSLB) accident. Results of the calculations indicate that cracks which would remain stable during a MSLB accident can be detected by ECT. (See Topical Report 008, Figure IX-2).

Leakage rates for various tube axial loadings, including tubes which lost pre-tension prior to repair, and crack arc length were determined by the licensee (See Topical Report 008, Rev. 3, Figure IX-5 and IX-6). Results show that leakage rates for predicted tube axial loadings will be detectable so that cracks below a size which can grow circumferentially during operations will be detected before reaching the critical size for propagation. The staff and our consultants (SSER Attachment No. 1) have evaluated the information provided and concur with the licensee's conclusions. In TDR-488, the licensee provided data which demonstrate that primary-to-secondary leakage is approximately 1.0 GPH during steady state conditions, and increased to a maximum of approximately 2.6 GPH during the third cooldown transient when tube tension was maximized. If a through-wall crack of sufficient length to propagate due to flow-induced vibration exists, a minimum leakage rate of 23 GPH is predicted for the most limiting tube. Leakage rates for non-limiting tubes are predicted at up to 80 GPH. Therefore, because of the low primary-to-secondary leakage rates during steady state and transient conditions, we find that there is reasonable assurance that the OTSG's do not contain critical size defects which could jeopardize the tube integrity when subjected to postulated accident design basis tube loadings.

In Attachment No. 1 to this supplement, our consultant indicated that the effect on crack propagation of residual stress fields in the formed tubes and the effect during heatup of tube bowing on vibrational characteristics should be further addressed by the licensee. As discussed below, the staff finds that additional discussion of the topics by the licensee is not required.

In Section V.C.1.c of the Topical Report 008, Rev. 3, the licensee stated that a transition length between 0.125 and 0.25-inch would be a goal, with a minimum acceptable transition length of 0.1-inch for the kinetically expanded tubes. This transition length is significantly longer than the original as-fabricated transition length of 0.0625-inch stated in Reference 17 of the Topical Report. The increase in transition length will cause a corresponding decrease in strain in the transition zone. Therefore, we find that the residual stresses in the transition zone of the kinetically expanded tubes would be lower than in the as-fabricated condition. Consequently, we conclude the transition zones should not be more susceptible to failure than the original as-fabricated transition zones.

Tube bowing is only of concern during plant heatup because the OTSG tubes which are relatively thin reach temperatures in thermal equilibrium with the coolant more rapidly than the OTSG shell and thus expand proportionally more rapidly than the shell during heatup. By letter dated September 30, 1983, the licensee indicated that tubes which have experienced a loss of pre-tension may exhibit bowing deflections during heatup which may allow them to touch adjacent tubes. During heatup, stress in bowed tubes will remain compressive and, therefore, the loading will not accelerate crack propagation. Since there is little or no flow during heatup, little or no flow-induced vibration exists. Consequently, the excitation force is miminal during heatup, and the flow-induced vibration of these tubes should remain below the levels exhibited by nominal tubes at full power.

Based on the above evaluation the staff finds:

1. Cracks which are large enough, i.e., critical size, to propagate due to flow-induced vibration are readily detectable by ECT;

2. Cracks which are below the threshold of ECT detectability will not propagate under combined cyclic, flow-induced and thermal loadings;

3. The maximum crack size which will remain stable during a MSLB has been determined;

4. Through-wall defects which may propagate during operation can be detected well below the threshold size that could fail during a MSLB. Therefore, reasonable assurance exists that the potential for rapidly propagating failure of steam generator tubes due to flow-induced vibration is minimized."

3.5 Cleanup of the Contaminant

In the SER, we stated that all piping will be flushed to remove soluble sulfur contaminants, that the administrative limit for sulfur in the coolant is <0.1 ppm, and that the licensee proposed to remove sulfur contamination on the RCS pressure boundary components by an alkaline peroxide treatment. By letter dated September 30, 1983, the licensee stated that all piping larger than 1 inch in diameter has been flushed to remove soluble sulfur contaminants. The SER referred to an administrative limit of 0.1 ppm for sulfur in the coolant. The limit is for sulfate ion rather than sulfur.

In Topical Report 008, Rev. 3, the licensee indicated that the alkaline peroxide treatment for the desulfurization of RCS surfaces has been carried out. The actual treatment conditions, the measurements and the results obtained throughout the desulfurization operation were also described. Based on our review of this information, we find that our previous conclusions on this topic remain unchanged.

This section should now read:

"All RCS tanks, components and piping larger than 1 inch diameter, which had contained sulfur impurities, have been flushed to remove soluble sulfur contaminants. Due to the small volume of fluid in pipes with less than a 1-inch diameter compared with the total volume or the reactor coolant system, flushing of these small lines is not warranted. Based on Topical Report, 008, Rev. 3, sulfate concentrations ($SO_4^{=}$) remaining in the coolant have been reduced to less than 0.1 ppm. In this concentration range, sulfate ion does not have a significant corrosive effect. If the sulfur is present as thiosulfate ion, S_2O_3, testing conducted by the staff consultant (NUREG-1019, Attachment 2) has shown that the threshold concentration for the initiation of SCC in aerated borated water is about 0.075 ppm for sensitized 304 stainless steel and about 1 ppm for sensitized Inconel 600. No thiosulfate was detected in the coolant.

The staff consultant (NUREG-1019, Attachment 2) has also demonstrated that the initiation and propagation of SCC in these alloys at temperatures below 150°C is suppressed by the addition of LiOH, which has been used in many reactors for pH control without negative effects. A Li/S ratio of 10 in the solution is sufficient to achieve this suppression. The staff consultant further states (NUREG-1019, Attachment 2) that thiosulfate ion affects SCC by electromigration into the propagating crack; partial neutralization of boric acid by LiOH provides competing borate anions which exclude thiosulfate anions from the crack. The licensee proposes to maintain the lithium concentration in the RCS at 1 to 2 ppm, which provides an adequate excess of lithium over the maximum administratively allowed sulfate concentration of 0.1 ppm. The staff finds that this action is consistent with the staff consultant's recommendation with which the staff is in agreement (NUREG-1019, Attachments 2-4) and, therefore, is acceptable.

After the removal of dissolved sulfur from the RCS, a concern remained that sulfur trapped in the oxide corrosion film on reactor surfaces might be converted by some sequence of operating conditions in the future to more corrosive and active species. The staff consultant (NUREG-1019, Attachment 4) indicates that metallic sulfides (MS) can react with oxygen to form thiosulfate:

$$2\ MS + H_2O + 2O_2 \rightarrow 2\ MO + S_2O_3^{=} + 2H^+$$

After the flushing operation, approximate surface sulfur concentrations on steam generator tube and other RCS surfaces were available for estimating the potential of regenerating thiosulfate from sulfide. Estimates of surface sulfur concentrations, based mainly on swipe tests, ranged over more than an order of magnitude, with the larger values as high as 10μg sulfur/cm^2. If all of this sulfur dissolved in the coolant volume, the sulfur concentration would amount to a few ppm. In a state of intermediate valence, this concentration of sulfur would have the potential to reinitiate the corrosion mechanism.

The licensee has carried out an extensive series of stress corrosion tests on sections of sulfur-contaminated steam generator tubes from TMI-1 under conditions simulating those that resulted in the original failures of these tubes. Even in the absence of added LiOH, no initiation of SCC and no propagation of existing cracks were observed. These negative results, however, did not provide adequate assurance that some untested combination of exposure conditions would not liberate aggressive sulfur species.

To reduce the likelihood of corrosion problems from the sulfur remaining on the RCS pressure boundary component and piping surfaces, the licensee has desulfurized these surfaces by oxidation with a dilute solution of hydrogen peroxide (H_2O_2). The approximate treatment conditions are summarized in the following table.

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

The pH of the system was maintained within the desired range by the addition of ammonium hydroxide. The concentration of H_2O_2 was kept at 15 to 25 ppm by the injection of concentrated H_2O_2 into the RCS using positive displacement pumps. The extent of cleanup was assessed by analyzing for sulfate in the reactor coolant.

After treatment for 400 hours, the sulfate concentration reached a plateau at 0.4 ppm, corresponding to the removal of approximately 0.33 lbs of sulfate from the RCS surfaces. This observation, combined with the test data that 50 to 80% of the surface sulfur on TMI-1 steam generator tubes was removed by the peroxide treatment, provides the first reliable indication of the extent of sulfur contamination of the RCS surfaces. The amount of surface sulfur was within the broad range indicated by swipe tests on tube specimens from the TMI-1 steam generators. As in the licensee's laboratory tests, the sulfate concentration initially increased, then levelled off at a constant value, indicating that all of the surface sulfur accessible to the reagent had been removed. The dissolved sulfate, ammonia, lithium and other ionic impurities were removed from the coolant by ion-exchange resin in the letdown purification system. The small quantity of sulfur removed from the reactor surfaces by the peroxide treatment indicates (1) that the extent of the original contamination was low, and (2) that the amount remaining on the surfaces after desulfurization is very low. According to the licensee's tests, the dissolution of the remaining sulfur would be slow, and if it all dissolved instantaneously would produce a sulfate concentration of only 0.1 to 0.4 ppm in the coolant. However, during the anticipated slow dissolution process, sulfur released to the coolant is continuously removed by the letdown system purification ion-exchangers and the actual concentrations of sulfur should remain at less than 0.1 ppm. The staff, therefore, finds that there is reasonable assurance that the peroxide treatment has effectively reduced the sulfur contamination of the reactor surfaces to an acceptable extent. The potential for sulfur-assisted corrosion during subsequent reactor operation is further diminished by the measures described in the Safety Evaluation for monitoring the sulfate concentration and adding lithium to the coolant.

Subsequent to the desulfurization treatment, the licensee carried out a pre-critical steam generator hot functional test program which included a series of rapid cooldown tests of the steam generators from 530°F to 350°F. Axial stress on the steam generator tubes is at a maximum during cooldown. Therefore, through-wall circumferential cracks which may exist can be predicted to open wider and increase in leakage rate. The condenser exhaust was monitored for Krypton-85, using two calibrated independent analyzers and grab samples analyzed off-site, which had been added to the primary coolant as a leak indicator. The primary-to-secondary leak rate was well below the Technical Specification limit during all phases of the pre-critical steam generator hot functional test. The rapid cooldown did not result in significant additional leakage, as indicated by Krypton-85 analyses and by analyses of the steam generator water for boron and other primary coolant constituents. We independently verified the licensee's analytical results, the method of calculation and the degree of agreement among the different measurement methods. We find that the licensee's leak detection methods will detect primary to secondary leakage at levels significantly below the shutdown limit of 0.1 GPM above background.

These results provide added assurance that the repaired tubes are leak-tight and the contaminant has been reduced to concentrations below which corrosion should not re-initiate."

3.6 Procedures to Prevent Re-Introduction of Contaminants

In the SER, we stated that the licensee had taken measures to prevent the re-introduction of contaminants. By letter dated September 30, 1983, the licensee brought several items to our attention.

In the SER, we stated that all RCS piping was flushed to remove the soluble sulfur. By letter dated September 30, 1983, the licensee indicated that only the RCS piping larger than one inch in diameter was flushed. Because piping smaller than one inch in diameter is a relatively insignificant fraction of the total system, we agree with the licensee that the flushing of piping of one-inch and larger diameter is acceptable.

In the SER, we stated that the coolant will be sampled daily for sulfur analysis and continuously monitored for pH and conductivity. By letter dated September 30, 1983, the licensee informed us that the coolant was analyzed daily for sulfate rather than sulfur, and that the pH and conductivity were monitored five times a week rather than continuously. The purpose of daily sulfate analysis is for early detection of sulfur contamination of the primary coolant; therefore, in this case both sulfate and sulfur analyses would yield the same conclusions. The frequency for pH and conductivity monitoring had been incorrectly stated to be continuous in the SER. In our opinion, monitoring of pH and conductivity 5 times per week is sufficient to provide information on the chemistry conditions of the primary coolant system. We agree with the licensee that the analysis for sulfate instead of sulfur is acceptable, and the frequency for monitoring the pH and conductivity is adequate.

In Table 3.6-1 of the SER, we stated that the new limit for chloride was $\leq$ 0.15 ppm and for sodium $\leq$ 1.0 ppm. By Rev. 3 of Topical 008, the licensee reduced their limits for chloride and sodium to $\leq$ 0.1 ppm.

Additionally, a typographical error existed in the lithium limits which should read, old limit 0.2 to 2.0 ppm, new limit 1.0 to 2.0 ppm. We find that the proposed reductions in impurity limits for chloride and sodium are on the conservative side and, therefore, are acceptable.

In the SER, we stated that the RCS will be treated with an alkaline peroxide. By Topical Report 008, Rev. 3, the licensee informed us that the RCS has been treated with a lithium containing hydrogen peroxide solution of pH between 8.0 and 8.5. This meets the commitment made by the licensee.

Based on the above, we find that there is no significant change from our previous evaluation and, therefore, the conclusion remains unchanged.

To reflect these acceptable changes, this section should now read:

> "The following measures have been implemented to prevent re-introduction of contaminants to the RCS.
>
> 1. The sodium thiosulfate tank has been drained and the piping connecting it to the RCS has been physically severed.
>
> 2. All RCS piping larger than 1 inch in diameter, tanks, valves, the reactor vessel and other components which had contacted thiosulfate solutions were flushed to remove soluble sulfur compounds to a concentration of less than 0.1 ppm sulfate in the coolant.
>
> 3. Administrative controls have been instituted on all pathways by which foreign chemicals might be injected into the RCS to minimize the potential for reintroduction of contaminants. These pathways include the Lithium Hydroxide Mix

Tank, the Boric Acid Mix Tank, the Reactor Coolant Bleed Tanks, the Borated Water Storage Tank and the Sodium Hydroxide Tank.

4. New analytical procedures have been implemented to detect the ingress of deleterious chemicals. The coolant will be sampled daily for sulfate analysis while pH and conductivity will be monitored five times per week.
5. New limits have been placed on primary water chemistry to prevent the development of an aggressive coolant environment. These changes are summarized in Table 3.6-1.

6. The RCS has been treated with an alkaline peroxide to remove a large fraction of the sulfur occluded in the oxide corrosion film on RCS surfaces. The tightly bound remaining sulfur will not be subject to sudden release to the coolant in corrosive concentrations.

The staff concludes that the above listed measures provide reasonable assurance that sulfur-containing contaminants will not be re-introduced to the RCS."

3.7 Post-Repair Testing And Operational Crack Arrest Considerations

In Rev. 3 of Topical Report 008, the licensee provided the results of the reactor coolant system peroxide chemical cleaning program to remove residual sulfur. The results demonstrate that the cleaning was conducted as committed to by the licensee. This confirms our conclusions in the SER.

In the SER, we stated that a hot functional test of the OTSG will be conducted by the licensee prior to normal pre-critical hot functionals.

The OTSG hot functional will take approximately thirty days and include extensive leak testing and transients which will maximize stresses on the tubing.

By letter dated October 25, 1983, the licensee provided TDR-488 which contains information on the OTSG pre-critical non-nuclear hot functional testing. Primary-to-secondary leakage was monitored during the entire test period, using Krypton-85 monitoring as discussed in Section 3.5 of this report. Based on the OTSG leakage results, the licensee has established a baseline leakage rate of 1.0 GPH which is 1/60 of the Technical Specification limit. This low rate of primary-to-secondary leakage provides additional confirmation that the kinetic expansion procedure is an effective repair method. During subsequent operations, if leakage increases by 0.1 GPM (6.0 GPH) above background the plant will be shut down, the OTSG's examined, and repaired as necessary. Reactor coolant system analysis showed sulfate concentrations between 20 PPb and 76 PPb, which provides additional confirmation that the principal sources of sulfur have been removed. The low baseline primary-to-secondary leakage and low reactor coolant sulfate concentrations confirm our conclusions in the SER.

Supplemental Safety Evaluation
TMI-1 OTSG Repair
Proposed Revisions to License Conditions

1. Unchanged.

2. Unchanged.

3. The licensee shall conduct eddy-current examinations, essentially consistent with the inspection plan defined in Table 3.3-1, either 90 calendar days after reaching full power, or 120 calendar days after exceeding 50% power operation whichever comes first.

4. The licensee shall confirm as early as feasible in post-critical operation the baseline primary-to-secondary leakage. If leakage exceeds the baseline leakage rate by more than 0.1 GPM, the plant shall be shut down and leak tested. If any increased leakage above baseline is due to defects in the tube free span, the leaking tube(s) shall be removed from service. Upon reaching operating conditions after removing leaking tubes from service, the baseline leakage shall be reestablished as early as feasible, provided that the present technical specification limit of 1.0 GPM is not exceeded.

5. The licensee shall perform an evaluation of operational data on leakage past the repaired joints 10 calendar years after restart to determine if additional laboratory design basis thermal and load cycle testing is necessary to ensure continued integrity of the repaired joint.

6. Unchanged.