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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
Sheldon J. Wolfe, Chairman
Dr. David L. Hetrick
Dr. James C. Lamb, III

In the Matter of	
	(NRC Docket No. 50-289 OLA)
METROPOLITAN EDISON COMPANY, ET AL.	ASLBP Docket No. 83-491-04 OLA
	(Steam Generator Repair)
(Three Mile Island Nuclear Station, Unit No. 1)	
	June 1, 1984

MEMORANDUM AND ORDER
(Rulings on Motions For Summary Disposition)

MEMORANDUM

I. Background

On February 24, 1984, the Licensee and the Staff respectively filed motions for summary disposition pursuant to 10 C.F.R. § 2.749, and, on March 20, 1984, the Staff filed a response supporting the Licensee's motion. On March 19, the Joint Intervenors filed their response opposing the motions for summary disposition of their contentions. On April 3, Three Mile Island Alert, Inc. (TMIA) filed its response opposing the motions for summary disposition of its contentions. On April 25, 1984, the Board granted Licensee's motion for leave to file a reply to Joint Intervenors' response to Licensee's motion for summary disposition. (Licensee's reply, which accompanied its motion for leave,

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was also served on April 4, 1984.) On April 25th, the Board also granted Licensee's motion for leave to file a reply to TMIA's response to Licensee's motion for summary disposition.[1] (Licensee's reply, which accompanied its motion for leave, was also served on April 13, 1984.)

II. Discussion

The summary disposition procedure should be utilized on issues where there is no genuine issue of material fact to be heard so that evidentiary hearing time is not unnecessarily devoted to such issues. Statement of Policy On Conduct of Licensing Proceedings, CLI-81-8, 13 NRC 452, 457 (1981); Houston Lighting and Power Company (Allens Creek Nuclear Generating Station, Unit 1), ALAB-590, 11 NRC 542, 550 (1980).

10 C.F.R. § 2.749(a) provides that once a motion for summary disposition has been filed, the opposing party, with or without affidavits, may file an answer. Paragraph (a) further provides in pertinent part that:

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1 In this unpublished Memorandum and Order, on its own motion, the Board permitted TMIA, if it desired to do so, to file an affidavit of Dr. George Sih meeting the requirements of 10 C.F.R. § 2.749(b). TMIA had appended to its Response of April 3, 1984, two exhibits purportedly written by Dr. Sih, but had not submitted the appropriate affidavit. TMIA submitted Dr. Sih's affidavit and professional qualifications on May 8, 1984. He is the Director of the Institute of Fracture and Solid Mechanics at Lehigh University.

> . . . There shall be annexed to any answer opposing the motion a separate, short and concise statement of the material facts as to which it is contended that there exists a genuine issue to be heard. All material facts set forth in the statement required to be served by the moving party will be deemed to be admitted unless controverted by the statement required to be served by the opposing party.
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10 C.F.R. § 2.749(b) provides in pertinent part that:

> Affidavits shall set forth such facts as would be admissible in evidence and shall show affirmatively that the affiant is competent to testify to the matters stated therein . . . . When a motion for summary decision is made and supported as provided in this section, a party opposing the motion may not rest upon the mere allegations or denials of his answer; his answer by affidavits or as otherwise provided in this section must set forth specific facts showing that there is a genuine issue of fact. If no such answer is filed, the decision sought, if appropriate, shall be rendered.

10 C.F.R. § 2.749(d) provides in pertinent part that:

> The presiding officer shall render the decision sought if the filings in the proceeding, depositions, answers to interrogatories, and admissions on file, together with the statements of the parties and the affidavits, if any, show that there is no genuine issue as to any material fact and that the moving party is entitled to a decision as a matter of law . . . .
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III. Rulings on Contentions

TMIA Contention 1.a

> Neither Licensee nor the NRC Staff has demonstrated that the kinetic expansion steam generator tube repair technique, combined with selective tube plugging, provides reasonable assurance that the operation of TMI-1 with the as-repaired steam generator can be conducted without endangering the health and safety of the public, for the following reasons:[2]
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> a. Post repair and plant performance testing and analysis including the techniques used, empirical information collected, and data evaluation, and proposed license conditions are inadequate to provide sufficient assurance that tube ruptures, including but not limited to those which could result upon restart, a turbine trip at maximum power, thermal shock from inadvertent actuation of emergency feedwater at high power or following rapid cooldown after a LOCA, will be detected in time and prevented to avoid endangering the health and safety of the public through release of radiation into the environment beyond permissible limits.

In support of its Motion for Summary Disposition, the Licensee appended the affidavit of David G. Slear, TMI-1 Manager of Engineering Projects and his professional qualifications. We are satisfied that Mr. Slear is qualified to attest to the matters in his affidavit. The Licensee's statement of material facts, based on the Slear affidavit, includes the following material facts as to which it asserts that there is no genuine issue to be heard:

> 5. In November 1981, primary-to-secondary leakage was discovered during testing of the reactor coolant system. Detailed examination by eddy current testing (ECT) revealed defects in the tube walls of which 95 percent occurred within the top 7 inches of the upper tubesheet based on the initial ECT examination results.

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2 This introductory wording of TMIA Contention 1 will not be reiterated with respect to subparts b through d.

6-8. The tubes were repaired by expanding them within the upper tubesheet to provide a new seal to the tubesheet at a location below where the defects were detected. The kinetic process expansion closed the nominal 0.005-inch gap between the tubes and the tubesheet by detonating an explosive cord in a polyethelene insert that transmitted explosive energy to the tube wall therein creating an interference pressure between the tube and tubesheet. The use of kinetic expansions to seal heat exchanger tubes within tubesheets has a broad base of successful experience in heat exchangers such as steam generators.

9-10. The tubes were expanded from the top of the upper tubesheet down either 17 inches or 22 inches, depending on the elevation of the lowest ECT indication within the upper tubesheet. The expansion length was selected for each tube to provide at least a six-inch ECT indication-free expanded length between the lowest elevation ECT indication and the bottom of the expansion to serve as the new pressure boundary. To accomplish this, tubes having the lowest ECT indication within the uppermost 11 inches of the tubesheet received a 17-inch expansion, and tubes with the lowest ECT indication within the uppermost 16 inches received a 22-inch expansion. This also resulted in a minimum of two inches between the expanded/non-expanded transition zone of the tube and the lower face of the tubesheet. As a result of standardizing the expansion length, _i.e._, the 17- and 22-inch lengths, many tubes have an ECT indication-free expanded length greater than six inches. The expansion length was also selected such that there were no ECT indications in the 1/8" to 1/4" transition zone between the expanded and non-expanded portions of the tube.

11. The repair program at TMI-1 was in accord with the Technical Specifications of the operating license for TMI-1, which, in accordance with the licensing basis for the OTSG tubes, require that tubes with imperfections equal to or greater than 40 percent of the tube wall thickness be taken out of service by plugging. If a kinetically repaired tube has a 40 percent or greater through-wall ECT defect indication within the pressure boundary, that tube is removed from service by plugging. Thus, the tubes will be in compliance with the OTSG industry standard 40 percent plugging criteria.

12. The licensing basis for both the original, unrepaired tubes and for the kinetic expansion joint is as specified in General Design Criterion 14, 10 C.F.R. Part 50, Appendix A, _i.e._, "to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture."

13. With regard to loads that must be sustained by the kinetic expansion joint, the maximum tube load resulting from

design basis events for both the original unrepaired tubes and the repaired tubes is 3140 pounds (for a main steam line break accident) and is applied due to axial tension within the tube below the expansion joint. This load is due mainly from tube/steam generator axial differential thermal expansion when the tubes are cooled to a lower temperature than the cylindrical shell of the steam generator.

14. The Technical Specifications for TMI-1 require shutdown if the total leakage (including leakage past the kinetic expansion joint) for both steam generators exceed 1 gpm. In addition, the NRC's proposed license conditions for restart with repaired tubes require shutdown for inspection if a leakage increase exceeding 0.1 gpm above a pre-established baseline is detected.

15. An extensive testing program was conducted to qualify the kinetically expanded joint to the licensing basis. The qualification program has demonstrated that the expansion joint meets the licensing basis, and is at least as effective as the original rolled and welded joint in all relevant respects, including axial loads from the worst case design basis operating and accident conditions, tube preload considerations, residual stresses in the transition zone.

16. The expansion joint is required to sustain the maximum postulated loads from a design basis accident, which is an axial tensile load of 3140 lbs. resulting from a main steam line break.

18. The kinetic expansion process does not change the strength or dimension of the tubes in any manner which would adversely affect the stress levels seen by the tubes. This has been verified by the qualification program which demonstrated that the residual stresses and the resistance to stress assisted cracking in the transition zone are consistent with the original design of the steam generators, and concurred in by the Third Party Review Group (TPR) at page 15 of the TPR Report.

25. During the manufacture of the OTSGs, the tubes were stretched slightly so that they would be under a small axial tensile load of about 65-lbs. with the OTSG at ambient temperature. Although the 65-lb. load (preload) is small in comparison with other operating tube loads, the qualification program evaluated the effect of axial tension preload of the tubes, and changes in the preload. Strain measurements on expanded tubes in laboratory test blocks and in the B&W full scale steam generator indicated a reduction in the preload of less than 30 pounds due to the change in length of the tubing. This would result in a less than 30-pound increase in the maximum compressive load which could be experienced by the steam generator under design basis conditions (heatup to

operating temperatures), an insignificant increase compared to the 800 pounds necessary to initiate bowing and the 1025 pounds necessary for lateral tube displacement to contact adjacent tubes (for nominal dimensions).

35. 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; this basis has not been compromised by the kinetic expansion repair.

38. An inspection and monitoring program was conducted during the repair process to verify that the in-generator expansions conformed to those obtained in the qualification program. The program consisted of video surveillance within the OTSG upper head and measurements of the tube inner diameters by profilometry and by diameter gauging on a sampling basis.

44. Post-repair and plant performance testing and analysis provide additional assurance of the integrity of the repair. As discussed below, the objectives of the post-repair and plant performance testing have all been accomplished.

45. Post-repair and plant performance steam generator testing and analysis of the kinetically repaired tube joints have included both a cold and a hot testing program.

46-47. The cold leak testing program consisted of bubble testing 100% of the expansion joints to determine if further repair or plugging was necessary. In this test, the primary side is drained to a few inches above the upper tubesheet, and secondary side water level is lowered and pressurized to 150 psig with an inert gas below the upper tubesheet. Kinetic tube expansions and tubing above the lowered water level are leak tested by visually checking for gas bubbles in the upper head. This is a highly sensitive standard test used in OTSGs to locate leaking tubes and welds in the region within and near the upper tubesheet. In two successive 100% bubble tests, a total of only 26 leaking tubes were found in both steam generators. None of those leaks were determined to be in expansion joints, although four of the leaks were so small that their precise location was not determined.

48. The hot testing program included overall integrated leak tests of the steam generators conducted under hot standby conditions and during heatup and cooldown. These tests also applied axial loads on the kinetic expansion joints.

49. A Kr-85 tracer was injected into the primary system to provide a measurable indication of leakage on a continuous basis.

The tracer was injected during the initial heatup to 532°F and 2155 psig in accordance with normal operating procedure. Leak testing was then conducted continuously during the following phases:

(a) Operational Leak Test. This test is required by Technical Specifications whenever work has been performed on the reactor coolant system. The pressure in the primary system was raised to approximately 2285 psig, creating a differential pressure between the primary and secondary of approximately 1400 psig. This is expected to be the maximum differential pressure experienced by the repaired tube joints during normal operation.

(b) First Thermal Soak. Conditions were allowed to stabilize at 532°F and 2155 psig for approximately one week, to provide baseline leakage data and to allow monitoring of leakage for trends.

(c) Normal Cooldown Transient. A controlled cooldown was conducted according to normal procedure, at approximately 60°F/hr. for approximately three hours to 350°F. A tube-to-shell temperature difference of about 35°F placed thermal loads on the tubes.

(d) Second Thermal Soak. The reactor coolant system (RCS) temperature and pressure was returned to 532°F and 2155 psig and held there for 11 days. Leakage data was obtained for comparison with the earlier thermal soak, and to monitor for any developing trends.

(e) Accelerated Cooldown. A controlled cooldown was conducted at close to the maximum rate permitted by Technical Specifications, at approximately 90°F/hr. for approximately two hours. This transient was to apply greater loads to the repaired tubes than the earlier cooldown. A tube-to-shell temperature difference of about 47°F was achieved.

(f) Third Thermal Soak. The RCS temperature and pressure was returned to 532°F and 2155 psig, and held there for approximately 11 days. Leakage data was obtained for comparison with the earlier thermal soaks, and to monitor for trending.

(g) Third Cooldown. During this cooldown, at about 90°F/hr., additional steps were taken to achieve a tube-to-shell temperature difference of about 99°F in the "B" OTSG and 112°F in the "A" OTSG. This transient applied greater tube loads than expected during a cooldown conducted according to normal operating procedures.

50. The hot testing indicated an integrated leak rate for both steam generators of only 1 to 2 gph. Technical Specification limits allow up to 1 gpm (60 gph) for such leakage.

51. In addition to the qualification program, the in-process repair testing, and the post-repair testing and analyses, which demonstrate the adequacy of the kinetic expansion repair joint, the NRC will impose special license conditions requiring additional surveillance and testing during operation. These special license conditions provide added assurance against the possibility of tube rupture. Specifically, if any significant degradation of the kinetic expansion joints were beginning to occur during plant operation, leakage would increase and the steam generator (and plant) shut down, tested and repaired, if necessary.

52. Shutdown for inspection will be required if a leakage increase of only 0.1 gpm is detected. This value is only 0.1 of the Technical Specifications limit for normal plant operation.

53. The plant will be required to be shut down after a short period of operation for performance of a special eddy current test (ECT) program. This testing will be performed 90 calendar days after reaching full power or 120 calendar days after exceeding 50 percent power operation, whichever comes first. The special ECT provides additional assurance that degradation of the kinetic expansion joint is not occurring and going undetected.

54, Licensee will be required to perform its power ascension program at staged intervals, with continuous leak testing and intervals for evaluation of the leakage trends after each stage.

55. Licensee will also be required to report at frequent intervals on its on-going long term corrosion lead testing program. These tests involve corrosion tests of actual TMI-1 tube samples, with specimens representative of both the expanded and unexpanded regions, including the transition zones. The tests are under simulated operating conditions, including water chemistry, and will encompass tube load and thermal cycling effects. These tests will lead operation of the plant by at least one year.

56-57. The qualification program, together with the in-process repair testing, has demonstrated that the repaired tubes are in conformance with the original licensing basis. Meeting the design basis provides the same reasonable assurance that tube ruptures will not occur during any postulated operating transients, including those associated with restart, turbine trip at maximum power, thermal shock from inadvertent actuation of emergency feedwater at high power, and rapid cooldown following a loss-of-coolant accident (LOCA), and additional assurance is provided by the post-repair and plant performance testing.

58. The loads on the steam generator tubes have been evaluated for normal operating transients and design basis accidents. The worst case situation is the main steam line break (MSLB) which is conservatively analyzed to result in an axial tension load of 3140 lbs. on the expansion joint. All of the loads experienced by the expansion joint during restart, including those resulting from heatup, cooldown, power escalation, and planned transients during power escalation, are well below the MSLB loads to which the repaired tubes have been qualified.

59-60. The repaired tubes have already experienced, without loss of integrity, loads intentionally imposed during post-repair hot testing equal to or greater than those that will be experienced during restart. The loads which would be experienced by the repaired tubes during turbine trip at maximum power, thermal shock from inadvertent actuation of emergency feedwater at high power, and rapid cooldown following a LOCA are all bounded by, and considerably less than, the MSLB loads.

61. A turbine trip at maximum power will result in an automatic reactor trip, and the plant will be stabilized at reactor coolant conditions which are comparable to "hot standby" conditions (RCS temperature at or above 531°F). This results in less tube load than for a design basis cooldown transient. Thus, significant changes in the OTSG shell to tube temperature difference and primary and secondary pressures from the power operating conditions are not produced as a result of a turbine trip.

62-63. Inadvertent acutation of emergency feedwater (EFW) at high power, i.e., a failure that results in starting of the EFW pumps while the plant is operating normally at high power, will not result in the injection of EFW into the steam generators. The design of the TMI-1 EFW system is such that once the EFW pumps are initiated, the actual flow to the OTSGs is controlled by valves which respond to a flow demand signal generated by the OTSG level control system. The water level in the OTSG at high power levels is much higher than the OTSG EFW level setpoint at which the EFW flow control valves are initiated to open. The EFW pumps are initiated by signals other than and independent of the OTSG level. Therefore, inadvertent actuation of the EFW pumps will not result in EFW injection into the OTSG and will not result in any change to the OTSG tube stresses.

64-66. Even if EFW injection into the OTSG were to occur, the resulting thermal stresses would not result in stresses sufficient to cause rupture of the repaired tubes. The location of any thermal shock stress condition, due to impingement of cold water that could occur on a tube that was repaired, would be remote from the repaired portion of the tube (about two feet or greater), and the direct thermal shock stress effects would affect only a portion of the tube. The only effect would be a slight decrease in the average tube temperature. Consequently, only a slight change in tube load would occur, far less than the qualification loads.

67. Rapid cooldown following a LOCA will not result in stresses sufficient to cause a rupture of the repaired tubes. The maximum tube load for a LOCA, including the effects of subsequent rapid cooldown, is 2641 pounds. This is well below the 3140-lb. load for which the repaired tubes have been qualified by testing for the main steam line break condition.

In support of its Motion, the Staff appended the joint affidavit of two NRC engineers -- Conrad E. McCracken, Chief of the Chemical and Corrosion Technology Section in the Chemical Engineering Branch, and Dr. Jai Raj N. Rajan, a Mechanical Engineer in the Mechanical Engineering Branch. After reviewing their professional qualifications, we are satisfied that these two individuals are qualified to attest to the matters in the affidavit. The Staff's statement of material facts, based upon the joint affidavit, includes the following material facts as to which it asserts that there is no genuine issue to be heard:

2. Contrary to the assumption in Contention 1.a, the post repair and plant performance testing, analysis and license conditions are used only to verify and monitor that the repaired steam generators are performing as anticipated. They are not relied upon as the basis for determining that the kinetic expansion repair technique pertaining to tube rupture is adequate to provide sufficient assurance that tube ruptures will be detected in time and prevented to avoid endangering the health and safety of the public through release of radiation into the environment beyond permissible limits.

3. The procedures to prevent re-introduction of contaminants (NUREG-1019 and Supplement No. 1, Section 3.6), post-repair testing and operational crack arrest considerations (NUREG-1019 and

Supplement No. 1, Section 3.7) and license conditions (NUREG-1019 and Supplement No. 1, Section 5.2) are consistent with state-of-the-art and are equally or more restrictive than those in place at most operating nuclear power plants.

4. The basis for acceptability of the kinetic expansion repair techniques pertaining to the tube rupture is the determination, which the Staff has made, that adequate assurances exist that the steam generator tube-to-tubesheet joint has been repaired to conform to the original licensing basis and technical specification requirements. As discussed in Section 3.4.1 of NUREG-1019 and Topical Report 008, Rev. 3, Section V.B, it is required that the repaired joint sustain a pullout load of 3140 lb. This conforms with the original licensing basis. The 3140 lb. loading is based on the forces exerted during a main steam line break, which is the limiting design basis accident. Additionally, the technical specifications require that total primary to secondary leakage be maintained below 1.0 gallons per minute.

5. In order to determine whether adequate assurances exist that the steam generator tube to tubesheet joint has been repaired to conform to the original licensing basis and technical specification requirements, licensee conducted extensive qualification testing using archive tubing, actual tubing removed from the TMI-1 steam generators and a full scale demonstration of the repair technique in an actual OTSG which has not been in service (Topical Report 008, Rev. 3, Section V.C.). These tests demonstrated that the repaired joints exceeded the licensing basis pullout load.

6. Independently, the staff consultants at Franklin Research Center (NUREG-1019, Attachment No. 1) conducted leakage rate, load cycling and pullout tests which verified the licensee's findings. All of these test programs demonstrated that the kinetically expanded repaired joint exceeds the licensing basis requirements for load carrying and leakage and is therefore acceptable.

7. In addition to the technical specifications for leakage and licensing basis requirements on pullout load, the licensee has incorporated a number of other measures to ensure that the potential for tube rupture is no greater than or less than the original probability. These measures include:

a. An unexpanded, defect-free length of tubing within the upper tubesheet, above the secondary side of the upper tubesheet face. This section of tubing is seven inches long for the majority of tubes, and two inches long for approximately 5% of the tubes. The defect-free unexpanded length of tubing is sufficient to maintain the tubes fixed in the tubesheet even if a 360° circumferential crack occurs at the repair transition zone. (See NUREG-1019, Section 2 and NUREG-1019, Supplement No. 1, Section 1, last two paragraphs). Because the unexpanded tube is fixed in the tubesheet by approximately an 8 mil radial crevice, which is leak limiting, it is physically impossible to have a design basis tube rupture which assumes a double ended guillotine severance. Therefore, the probability of a steam generator tube rupture is no greater than prior to the repair process.

b. The transition length between the expanded and unexpanded portion of tubing was increased from the as-fabricated transition length. This results in a reduction in residual stresses (as indicated by hardness) in the transition zone. (See NUREG-1019, Supplement No. 1, page 11). The reduction in residual stresses using the kinetic expansion process was confirmed by hardness measurement (Topical Report 008, Rev. 3, page 40, Section (3) and NUREG-1019, page 19, Section c). The reduction in residual stresses reduces the possibility of stress corrosion cracking.

c. Although not required as part of the original licensing basis, leak and axial load qualification tests (Topical Report 008, Rev. 3, pages 38 and 39, Section 3.4.2 of NUREG-1019, and NUREG-1019 Supplement No. 1 and Attachment No. 1) were conducted for the repaired joint. These tests demonstrated that under design basis temperature and load cycling, the joint will continue to remain acceptable.

8. TMIA's contention that inadequate assurances are provided to address tube rupture "including but not limited to those which could result upon restart, a turbine trip from maximum power, thermal shock from inadvertent actuation of emergency feedwater at high power or following rapid cooldown after a LOCA" has no technical basis. The limiting design basis accident for producing loads on steam generator tubes is the main steam line break, which sets the repair pullout criteria of 3140 lb. Any other design basis accident, including those mentioned in TMIA Contention 1.a, will produce pullout loads which are less than 3140 lb. Therefore, reasonable assurances have been provided against tube rupture due to the contended mechanisms.

In its response opposing the motions for summary disposition, TMIA submitted 93 statements characterized as "statements of material facts as to which there are genuine issues to be heard" with respect to Contention 1.a. We have had considerable difficulty with the format of this response. Contrary to the requirements of 10 C.F.R. § 2.749(a), TMIA did not file a separate concise list of material facts asserted as genuine issues to be heard; thus, we are confronted with a very long list in which assertions, discussions and pleadings are intermixed. Moreover, TMIA has included new assertions and concerns that are outside the scope of Contention 1.a and were not addressed during the discovery process.

Before proceeding to a point-by-point discussion of TMIA's response concerning Contention 1.a, we pause to comment on the wording of this contention as it was admitted. We are being asked to rule whether the repair technique provides reasonable assurance that operation of TMI-1 can be conducted without endangering public health and safety. Contention 1.a further alleges that post repair and plant performance testing, and proposed license conditions, are inadequate to assure against steam-generator tube ruptures. The Licensee's motion of February 24, 1983, contains a lengthy discussion of qualification programs and in-process repair testing in addition to the matters raised in the contention (included here in part as Licensee's facts 15, 16, 18, 25, 35 and 38, supra). Much of TMIA's response is addressed to qualification programs and in-process repair testing (¶¶ 2, 5-65, and 70-73). However broadly one may read the contention in its concern for public health and safety, qualification programs and in-process testing are not included.

In Item 2 of its response, TMIA asserts that, since the Licensee places primary reliance upon its qualification program and in-process inspection of the kinetic expansions, the adequacy of Licensee's qualification program and in-process testing must first be determined. Whether this "primary reliance" is properly placed or not, we are constrained by the clear wording of the contention from considering the qualification program and the in-process testing.

We turn now to the remaining paragraphs of TMIA's response (¶¶ 3-4, 66-69, 74-83, 85-88, and 90-92). We retain TMIA's numbering.

> 3. Contrary to Licensee's implication at Licensee Facts ¶ 8, the repair program which Licensee has undertaken in this case is far from routine, and there is no evidence these types of repairs have ever been conducted at a nuclear power plant in the large scale manner as has been done at TMI-1. Indeed, the Staff has always considered the process unique and experimental. Attachment 1.
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> 4. Further, the fact that the kinetic expansion repair may have been used in other steam generators, Licensee Facts ¶ 8, is irrelevant without some evidence of its previous success rate.

There is a difference of opinion about the choice of words to be used in characterizing the repair process, and the word "experimental" seems to be TMIA's own. TMIA's ¶ 4 calls attention to the last sentence of Licensee's ¶ 8, which asserts that the use of kinetic expansions to seal heat exchanger tubes within tubesheets has a broad base of successful experience in heat exchangers such as steam generators. Licensee does not state whether this experience includes nuclear plant components other than the steam generators of TMI-1, or whether the experience includes repair of damaged heat exchangers, manufacture of new heat exchangers, or both.

> 66. Moreover, by failing to run the system through some hard transients in post repair testing, there is no technical basis to conclude the repairs can safely withstand such transients.

> 67. Clearly, no amount of qualification testing can insure that each individual tube has been properly expanded, or that it meets the qualification criteria. Each tube is unique and the only way to be sure each was properly expanded is to examine each of the 29,000 tubes individually, or to run the system through the actual loads which it was qualified to withstand.
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> 68. Licensee would probably argue that the sheer number of tubes which had to be repaired made it impractical for Licensee to conduct 100% profilometry verification or post expansion diameter gauging and depth check samplings . . . .
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> 69. Yet clearly, the individuality of each tube and its physical properties, as well as its surrounding environment, raises questions concerning potential problems. And while Licensee may have tried to take precautions to avoid minimize [sic] the risk of such problems, they are of sufficient concern to have at least demanded more extensive post repair testing.

Taken together, these paragraphs are arguments that the steam generator tubes should be exercised in some "hard transients" if not individually inspected. The "hard transients" of TMIA's ¶ 66 are presumably those suggested in TMIA's ¶ 67, <u>i.e.</u>, "run the system through the actual loads which it was qualified to withstand." This seems to imply that normal operation of TMI-1 should not resume until the plant has been successfully subjected to a series of deliberate design basis accidents. Alternatively, TMIA's ¶ 67 suggests that each of the 29,000 tubes be examined individually. Either alternative is unacceptable for obvious reasons (prohibitive expense, unacceptable risk, or both). In any case, TMIA's arguments in ¶¶ 66-69 advance no material facts showing that there are genuine issues to be tried.

> 74. Given the potential problems, as well as uncertainties regarding qualification testing, it is somewhat remarkable that post-repair testing was so limited.
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> 75. . . . Licensee did no post repair hardness testing on

corroded tubes, claiming such tests are " . . . not required to support any conclusion concerning the effectiveness or adequacy of the repair process." Licensee Response to TMIA Interrogatory 15. See Attachments 2 and 4, p. 2.

76. In addition, when questioned before an ACRS subcommittee on a major issue of concern, i.e., whether kinetic expansion may have caused the tubes to weaken, thus increasing the risk of tube failure, Licensee responded that they had examined the issue only peripherally, explaining,

> We have looked at wall thinning due to the explosive expansion process compared to hardening due to rolling. Hardening is a much less wall-thinning operation. What that says exactly I'm not sure, but that's the kind of a comparative statement between the two, between the ratcheting.

ACRS Tr. at 166 (emphasis added).

A portion of TMIA's ¶ 75 was not quoted here because it refers to aspects of Licensee's qualification program, which we have ruled to be outside the scope of Contention 1.a (supra). The remainder of the paragraph cites the lack of post repair hardness testing on corroded tubes. This lack is acknowledged in Licensee's Response to TMIA Interrogatory 15, but the only reason given is the brief claim quoted in TMIA's ¶ 75.

77. Second, the only post repair plant performance tests performed were the bubble leak test, Licensee Facts ¶ 46, and the hot functional test, where the steam generators were put through normal operating conditions. Licensee Facts ¶ 48 et seq. These tests can not overcome the already demonstrated deficiencies in the qualification program for several reasons.

78. First, leak test results may be misleading. Licensee has claimed that leaks are self-sealing because corrosion products will deposit in the cracks and seal the leaks. (Attachment 6-1; ACRS Tr. at 99-100). Further, as the Staff points out, due to the loss of pretension, the leakage rate for various threshold cracks may be reduced. (SER at 21). Thus, decreased leakage may mask cracks which additional compressive loads and bowing could cause to

mouth open, or to create new corrosion initiation sites. See Attachment 1, at p. 2.

79. Further, Licensee has remarked that there is inadequate technical data to really know the significance of corrosion sealed cracks as they impact on tube integrity. ACRS Tr. at 99-100.

There is disagreement about the location of self-sealing leaks, but there is a possibility that this is relevant to proposed license conditions. (See TMIA ¶ 87, infra).

80. Second, the repaired system has not been run through any transient conditions, such as those listed in TMIA Contention 1.a or a MSLB. Licensee asserts that by qualifying tubes to withstand at 3140 lb. pullout load or 1025 lb. compressive load, there is no need to test the system out. Yet there is a clear need to determine if these tubes actually can withstand these loads while maintaining tube integrity. See, supra.

As we ruled above, any reference to qualification testing exceeds the scope of the contention and will not be considered. Severe transient testing of the type suggested does not seem feasible (see discussion re ¶¶ 66-69, supra). In any event, this argument advances no material facts showing that there is a genuine issue to be tried.

81. In response to TMIA Contention 1.a, Licensee discusses the impact of one transient: inadvertent actuation of emergency feedwater at high power. Licensee Facts ¶ 62 et seq. Licensee states that if emergency feedwater is injected into the steam generator, which Licensee asserts is unlikely, the resulting thermal stresses will not be enough to cause a rupture because the location of any thermal shock would be remote from the repaired portion of the tube. Licensee Facts ¶ 65. TMIA members are not technical experts and thus we do not know the precise location where the EFW may strike the steam generators. Yet it seems clear that no matter where the direct thermal shock is, the increased load will pull on the entire tube, thus increasing risk of pullout anywhere on the tube, particularly including areas of high residual stress like the transition or HAZ zone. The effect of this particular transient has not been adequately explained by Licensee.

We accept that portion of Licensee's technical explanation set forth in Licensee's ¶ 62-63. Indeed, as we know from experience at TMI-2, the starting of EFW pumps will not result in the injection of EFW into the steam generators if the valves are closed. However, if the pumps were to start with the valves open, impingement of cold water on some repaired tubes would occur. TMIA is uncertain about the precise location of this (see TMIA's ¶ 81). Licensee's description, i.e., "remote from the repaired portion of the tube (about two feet or greater)" is rather vague (see Licensee's ¶ 64-66). If the EFW inlet is about two feet below the upper tubesheet, as Licensee seems to imply, it is not clear that this is sufficiently "remote" to justify Licensee's qualitative conclusion that only a slight change in tube load would occur.

82. Further, hot functional testing did not simulate the stresses which would result from a rapid cooldown following a LOCA, which by Licensee's own estimates would be 2641 lbs. Licensee Facts ¶ 67.

83. Moreover, at TMI-1, 31,000 tubes failed, and 29,000 tubes were kinetically expanded. The TMI-1 steam generators are considered by the NRC to be the worst damaged steam generators in the country. See, Statement of Harold Denton, Director of Nuclear Reactor Regulation, before the Committee on Interior and Insular Affairs, February 1, 1982. The amount of damage can not compare to that of any other steam generator in the industry. Yet the accident consequences of <u>one rupture</u>, <u>i.e</u>., what can be expected in a normal, design basis steam generator, was of sufficient concern to cause the Staff to write in 1982:

> During postulated accident conditions, such as main steam line break (MSLB), feedwater line break, or LOCA, the S.G. tubes are subject to increased pressure differentials and possible pressure waves (<u>e.g</u>., subcooled decompression phenomena) and vibrational loadings. These loads increase the potential for failure of degraded S.G. tubes, which could exacerbate the accident sequence. In the event of MSLB,

> failed S.G. tubes would provide a leakage path from the primary to secondary system and several potential leak paths for radioactivity to the environment would then exist. In the event of a LOCA, the core reflood rate could be retarded by steam binding . . . S.G. tube failures would create secondary to primary leak path which aggravates the steam binding effect and could lead to ineffective reflooding of the core . . . . Large MSLBs and LOCAs are considered extremely low probability events, but are postulated as bounding conditions. More realistic events might include small and intermediate size MSLBs and LOCAs. Although these postulated accidents pose a less severe challenge to S.G. tube integrity, tube ruptures leading to or following such events could have serious consequences.

SECY 82-72, p. 3.

Again, severe transient testing is suggested, this time in the context of rapid cooldown from a loss-of-coolant accident. It is not clear how hot functional testing could simulate the effects of a severe LOCA on the steam generators. Tube ruptures during such events could have serious consequences, but it is not clear whether the probability of such consequences is increased by the repair procedure.

85. Licensee has assured compliance with certain required "license conditions" to provide assurance against possible tube ruptures. Licensee Facts ¶ 51.

86. One condition is a requirement of plant shutdown if increased leakage of .1 gpm is detected. Licensee Facts ¶ 52. While this limit may be only 10% of the technical specification current limits, the tech specs are themselves "the most liberal in the PWR industry." Attachment 1.

87. As has already been discussed, leak rates may indeed be misleading, and may be inadequate to detect cracks which propagate thruwall in one day. See, ¶ 78, <u>supra</u>.

88. Further, as the Staff points out, due to the loss of pretension, the leakage rate for various threshold cracks may be reduced. SER at 21. Thus, decreased leaks may mask cracks which additional compressive loads and bowing could cause to mouth open.

90. Another License Condition is a promise to conduct a special ECT after either the first 90 or 120 days of operation. Licensee Facts ¶ 53. Even apart from the problems raised by ECT, (see, ¶¶, supra), a one time ECT can hardly guarantee that as the plant ages, cracks will even be noticed. The Staff originally believed the "prudent" approach to be at least on ECT after 30-60 days, followed by one after 150-210 days, and then during refueling. Attachment 1. No explanation for this reversal of position is provided.

91. In addition, power ascension will be at staged intervals. The TPR, however, recommended "substantial" extended operation at low power, and even suggested operation with one steam generator at a time at high power.

92. Licensee also will rely on long term corrosion tests to simulate operating conditions. As discussed previously, accurate simulation of actual TMI-1 tube properties is virtually impossible. See, ¶¶, supra.

These paragraphs allege the inadequacy of certain of the Staff's proposed license conditions which are supposed to provide added assurance against the possibility of tube rupture. The proposed License conditions are described in Licensee's ¶¶ 51-55, supra, and in NUREG-1019 at p. 46. TMIA is questioning whether leak rate measurements will be sufficiently reliable, whether ECT testing will be sufficiently frequent, whether the power ascension program is sufficiently cautious, and whether the long-term corrosion tests will adequately simulate operating conditions. TMIA has not related any of its allegations to a specific scenario for tube rupture, nor has it offered specific proposals for revising the license conditions. Nevertheless, TMIA's assertions are of sufficient concern to us that we cannot resolve this issue without more detailed information.

In ruling on the motion for summary disposition of Contention 1.a, we have not been greatly assisted by TMIA's response. Instead, we concentrate on whether Licensee and Staff have successfully shown that there is nc genuine issue of material fact to be heard.

The Staff argues that the post-repair plant testing program and proposed license conditions do not form the basis for the Staff's determination that the kinetic expansion repair techniques are acceptable (Staff Motion at 4); rather, the "acceptability . . . is based on the Staff's determination that adequate assurance exists that the steam generator tube to tubesheet joint has been repaired to conform to the original licensing basis and technical specification requirements" (Staff Motion, at 5). The Licensee argues that the repaired tubes have been returned to the original design basis, and that there is therefore, reasonable assurance that tube rupture will not occur . . . as a result of any design basis event. (Licensee Motion at 10). Both Licensee and Staff argue that post-repair plant testing and proposed license conditions are for the purpose of providing additional assurance. Underlying this is an implication that post-repair testing and new license conditions are not necessary in determining whether TMI-1 should be permitted to operate.

We reject this implication. A major repair effort of this magnitude cannot be fully evaluated without assurance that performance after start-up will be monitored with extreme care. Our review of the Licensee's and Staff's motions have left us with some uncertainties, some of which were alluded to in our remarks following TMIA's paragraphs in response to those motions.

The motions for summary disposition of TMIA's Contention 1.a are denied in part. To provide guidance in preparing for the forthcoming hearing, we offer a summary of our uncertainties as follows:

1. The rationale underlying certain proposed license conditions should be addressed, with attention to:

   a. Reliability of leak rate measurements.

   b. Method of determining frequency of ECT tests.

   c. Method of determining power ascension limitations.

   d. Adequacy of simulation of operating conditions by long-term corrosion tests.

2. The effect of inadvertent initiation of emergency feedwater flow at high power or following rapid cooldown after a LOCA should be addressed, with attention to calculation of maximum transient stresses in steam generator tubes.

3. The reasons for not including hardness tests on repaired tubes in the post repair testing program should be addressed.

4. Recalling Licensee's statement in ¶ 6-8 that the use of kinetic expansions to seal heat exchanger tubes within tubesheets has a broad base of successful experience, information is requested about whether tube integrity during subsequent operation depends on whether the process is a repair, or a manufacturing process using new materials.

TMIA Contention 1.b

Because of the enormous number of tubes in both steam generators which have undergone this repair process, (1) the possibility of a simultaneous rupture in each steam generator, which would force the operator to accomplish cooldown and depressurization using at least one faulted steam generator, resulting in release of radiation into the environment beyond permissible levels, "isn't an incredible event," (see, September 19, 1982 memorandum from Paul Shewmon, then Chairman of the ACRS). (2) and could lead to a sequence of events not encompassed by emergency procedures, (3) and in the course of a LOCA, such a scenario could create essentially uncoolable conditions.

In support of its Motion for Summary Disposition, the Licensee appended the affidavit of David G. Slear (cited in connection with TMIA Contention 1.a, <u>supra</u>). The Licensee's statement of material facts in connection with TMIA Contention 1.b, based on the Slear affidavit, consists of the following material facts as to which the Licensee asserts that there is no genuine issue to be heard:

> 68-69. The kinetically expanded joints, including the effects of expansion on the tubes, have been demonstrated to fully meet the original licensing basis. The kinetic expansion joint is well inside the tubesheet where the tight constraints preclude tube rupture and rupture-magnitude leakage.
>
> 70-71. Added assurance against the potential for tube rupture is provided by the in-process repair testing, the post-repair and plant performance testing and analyses, and the additional special license conditions. Therefore, the kinetic expansion repair process will not increase the likelihood of a simultaneous tube rupture in each steam generator, and thus will not increase the attendant likelihood of requiring the operator to accomplish cooldown and depressurization using at least one faulted steam generator, the likelihood of the occurrence of a sequence of events not encompassed by the TMI-1 emergency procedures, or the likelihood of the occurrence of a scenario during the course of a LOCA which would create essentially uncoolable conditions.

In support of its Motion, the staff appended (1) the joint affidavit of Conrad McCracken and Louis Frank, (2) the affidavit of Frank Orr, and (3) the affidavit of Walton L. Jensen. Mr. McCracken was cited in connection with TMIA Contention 1.a, <u>supra</u>. Mr. Frank is a Senior Materials Engineer in the Inservice Inspection Section, Nuclear Materials Branch, Division of Engineering (NRC). Mr. Orr is a Senior Nuclear Engineer in the Procedures and Systems Review Branch, Division of Human Factors Safety (NRC). Mr. Jensen is a Senior Nuclear Engineer in the Reactor Systems Branch (NRC). We are satisfied that these individuals are qualified to attest to the matters in their respective affidavits. The Staff's statement of material facts, based upon these affidavits, consists of the following material facts as to which the Staff asserts that there is no genuine issue to be heard:

2. Dr. Shewmon's memorandum of 9/19/82 is quoted out of context. Nowhere in Dr. Shewmon's memorandum is the efficacy or adequacy of the kinetic expansion tube repair process questioned, or even raised. Conversely, Dr. Shewmon is raising the issue of the number and location of tubes which are plugged (" . . . they will probably plug many more tubes than they originally planned.").

3. The fact that Dr. Shewmon's memorandum raises a concern about plugging, rather than tube expansion, is supported by Mr. Major's memorandum of September 30, 1982. There, Mr. Major states: "The first concern [raised by Shewmon] is the extent to which the TMI-1 steam generator tubes must be plugged and taken out of service, rather than being repaired by kinetic explosive expansion against the upper tubesheet." (Emphasis added). Both memoranda also indicate that they do not have current or exact data on the status of tubes being plugged. Therefore, the comments and concerns raised were speculative, not based on the actual situation at TMI-1.

4. Contention 1.b also implies that "the enormous number of tubes in both steam generators which have undergone this repair process" is somehow related to the potential for tube rupture. This contention lacks technical basis because the concern, in any repair process, is not how many tubes are repaired, but whether the repair method will restore the original tube integrity and how many tubes should have been repaired that were not (i.e. have unidentified defective tubes been left in service).

5. Licensee's tests (Topical Report 008, Rev. 3, Section V.C), confirmed by the Staff's evaluation (NUREG-1019, Section 3.4) and the Staff consultant's independent review (NUREG-1019, Attachment 1), demonstrate that the repaired tubes exceed the licensing basis requirement. To preclude the possibility of leaving unrepaired, defective tubes inservice, all tubes, in both OTSGs were repaired and plugged as required, as discussed in NUREG-1019, Section 2 and NUREG-1019, Supplement No. 1, Section I. Because all tubes have been repaired and plugged as required, adequate assurances exist that defective tubes have been removed from service. The Staff's conclusion is supported and verified by the extremely low primary to secondary leakage during

the steam generator hot functional testing. (See NUREG-1019, Supplement No. 1, page 18 and page 22).

6. Steam generators, when manufactured, incorporate corrosion allowances above ASME boiler and pressure vessel code requirements into the thickness of the tube walls, to allow for degradation during operation. In addition, more tubes are installed than are needed for full power operation, to permit removal from service of tubes which have become degraded.

7. The actual corrosion allowance and number of excess tubes is plant-specific. However, most steam generators have 10% to 30% more steam generator tubes than are necessary for full power operation. A number of steam generators are currently operating at full power with 10% to 25% of their tubes plugged. The Staff has also conservatively established a 40% through wall (i.e., 60% tube wall remaining) plugging criteria for defective tubes. Each licensee can elect to accept the conservative 40% plugging limit or perform calculations and testing to justify a less conservative plugging limit. TMI-1 has chosen the conservative 40% tube plugging limit, which is incorporated into the plant technical specifications.

7. The Shewmon and Major memoranda are referring to partial information indicating that some corrosion was being detected in tube free spans, outside of the tubesheet. However, as indicated clearly in both memoranda, the authors were unaware of the extent of the corrosion problem in the free span. Corrosion in the tube free span is the area of greatest concern because of the possibility for guillotine type tube ruptures, due to the lack of tube restraints as exists in the tubesheet.

8. Subsequent to the dates of the Shewmon and Major memoranda the extent of corrosion outside the tubesheet was accurately determined and characterized by 100% eddy current testing (ECT) of both OTSGs. These tests showed that less than 5% of the tubes had detectable corrosion outside of the tubesheet. NUREG-1019, Section 3.3, provides a thorough discussion of the ECT program, results, and future plans. Topical Report 008, Rev. 3, page 2 and Table I-3 provides a summary of the disposition for all OTSG tubes.

9. In light of the information provided (Topical Report 008, Rev. 3, and NUREG-1019) subsequent to the Shewmon and Major memoranda it is clear that the concerns expressed therein have been technically resolved because:

a. The extent of corrosion outside of the tubesheet at TMI-1 is less than that which exists in many other operating plants; and

b. Corrosion which did exist outside the tubesheet was repaired by plugging, in accordance with the technical specifications, to the same criteria as other plants are repaired. Therefore, the probability of single or multiple tube rupture is no greater at TMI-1 than any other plant, nor is the probability of single or multiple tube rupture any greater for TMI-1 now than prior to the corrosion problem.

10. In summary, the potential for simultaneous tube rupture in both steam generators is no more credible at TMI-1 than at any other plant. All plants are repaired to the same criteria to ensure that the probability of any tube ruptures remains low.

11. However, even if a beyond-design-basis simultaneous rupture in each steam generator were to occur, such ruptures and resultant scenarios are encompassed by GPU's Steam Generator Tube Rupture Guidelines, TDR-406, and Procedure EP-1202-5, OTSG Tube Leak/Rupture, as discussed in NUREG-1019, Section 4.3.1 and 4.3.2. In addition, as further discussed in Supplement 1 to NUREG-1019, Section 4.3.1, the provisions of the Emergency Plan provide adequate flexibility to the licensee's Emergency Director to deviate from procedures as necessary in order to deal with unforeseen events. As part of the TMI Action Plan, NUREG-0737, Item I.C.1, the emergency operating procedures at all PWRs are to be upgraded to address many multiple failures, beyond design basis events. TMI-1 has a program to develop and implement these procedures. These procedures will be symptom-oriented to provide additional flexibility in dealing with beyond-design-basis multiple failure events. Thus, even if beyond-design-basis multiple tube ruptures were to occur, such events are encompassed within existing emergency procedures.

12. The present procedures dealing with multiple steam generator tube ruptures are not required to and do not deal explicitly with the beyond-design-basis event of simultaneous LOCA and steam generator tube rupture in both team generators. This occurrence would be extremely unlikely because of the number of simultaneous failures involved. However, both the LOCA and steam generator tube rupture procedures direct the operator to maintain core cooling.

13. However, even if such extremely unlikely simultaneous accidents were to occur, the Staff is unable to postulate mechanistically a credible scenario which would create uncoolable conditions. Intervenors have raised questions in discovery about

steam binding. It has been postulated that, for large cold leg breaks, flow of steam from the steam generators into the reactor system would retard the recovering of the core by emergency coolant. The additional steam would retard flow of steam generated by the core through the coolant loops during the reflooding process. Steam must escape the core and flow out of the reactor vessel for the core to be adequately reflooded. Reactors designed by B&W, including TMI-1, do not depend on steam flow through the coolant loops for reflooding. TMI-1 has internal vent valves which would allow steam from the core to pass directly out the break without traversing the coolant loops. No credit was assumed for relief of steam from the core through the coolant loops in the ECCS analyses performed under 10 C.F.R. 50.46 for TMI-1. The Staff concludes that the creation of essentially uncoolable conditions by the scenario proposed by the contention is highly unlikely.

In its response opposing the motions for summary disposition, TMIA submitted the following statements:

1. Licensee has determined questions concerning simultaneous tube ruptures to be irrelevant. Licensee Facts ¶¶ 68-71. Licensee disputes concerns expressed by ACRS subcommittee Chairman Paul Shewmon and similar concerns in SECY 82-72.

2. The Staff asserts that the Paul Shewmon's memo, as further interpreted by Richard Major, is not supportive of the contention because Paul Shewmon was not concerned with the risk of simultaneous ruptures, but rather with tube plugging and solely with free span defects. Staff Facts ¶¶ 2, 3, 8-10.

3. The Staff's position clearly misinterprets the clear language of both the Shewmon and Major memos. Both address two concerns, one being tube plugging, the other being simultaneous ruptures.

4. Significantly, the Staff did not obtain an affidavit from Shewmon himself. The Staff's twisted interpretation is based on an affidavit of someone who had no first-hand knowledge of Paul Shewmon's intent, and whose interpretation should be given no weight.

5. On the other hand, in the absence of an affidavit from Shewmon, his remarks during an ACRS subcommittee meeting, which both Licensee and the Staff attended, should be entitled to a great deal of weight. Shewmon stated there,

> From a personal viewpoint, it seems to me that the thing you have to show is the odds are vanishingly small that you're

> going to have trouble on both team generators at once because of the excursion of faults you have had heretofore. And that may be an impossible problem, but it seems to me that that, at least in my mind, is a critical question rather than fatigue cracks.

ACRS Tr. at 159.

6. Further, Shewmon's concern was supported by the TPR's first report, which concluded "safe operation of the TMI-1 plant after repair of the steam generators will be dependent on several remaining major activities; [including] completion of analysis including . . . the contingency of multiple tube ruptures. TPR 2/18/83 at 4. Clearly, the TPR meant to distinguish the contingency of multiple tube ruptures from other possible situations which were tested and analyzed by Licensee. Licensee asserts that "these comments were intended merely to flag to the reader that the conclusions drawn were incomplete at that time since Licensee had not completed its analytical or planning efforts." Licensee Response to TMIA Interrogatory T-8.

7. Three months later, the TPR, for unexplained reasons, withdrew this as an open issue needing resolution before plant start up. The basis for the TPR's later conclusion that such analysis was no longer required is unexplained and at least raises suspicious questions. See, TPR 5/18/83 at p. 2. This is particularly true since the TPR was apparently sufficiently concerned with the possibility of simultaneous ruptures that it suggested running one steam generator at higher power than the other, which would have put this system in so abnormal a configuration that GPU refused to do it. TPR 2/18/83 p. 12; Reference Document 64.

8. It is clear that during all qualification testing done by Licensee in 1982, the consequences of multiple tube ruptures, which including ruptures in both steam generators, was never treated as a subject warranting special testing. And in fact, Licensee later asserts with regard to the simultaneous rupture case, that since this is "not a design basis accident for any plant, neither the TPR nor the Staff have required analysis for such an event in their respective approval for returning the plant to service." Motion at p. 26.

9. Clearly, as Paul Shewmon noted above, the number of failures and unique type of repair used in the TMI-1 steam generators demand that the risk and consequences of simultaneous ruptures receive special attention. The Staff and Licensee can not simply close their eyes to a contingency which the Staff has already considered of major importance with regard to <u>normal</u> steam

generators. (See, SECY 82-72, where the Staff notes that if ruptures occur in both steam generators, unless the plant can be rapidly depressurized and brought onto Residual Heat Removal, there is the potential to continuously lose ECC water outside the containment.)

10. Further, while the Staff maintains such a possibility is unlikely, no probabilistic risk assessment has been done. Attach. 7.

11. In contradiction to their stated position that the simultaneous tube rupture possibility requires no separate analysis, Licensee and the Staff both recognize that this contingency must be considered in operator training and emergency procedures. See, TDR 406.

12. However, whether emergency procedures will provide adequate guidance to instruct operators in the event of such an accident is a significant open issue. There is no question that when a simultaneous rupture occurs, no automatic system can cool the plant down. This type of accident requires the operators to respond with spur of the moment decisions, so that training is crucial. Further, operator instructions for simultaneous ruptures currently instruct operators to follow the steaming, filling, and isolation criteria as written for single tube ruptures, which themselves violate a number of past safety limits.

13. For example, the procedures reduce the subcooling margin in the RCS, which risks the formation of steam bubbles in the reactor and reactor coolant piping which could block the circulation of cooling water through the core. The Staff says that this will not occur, because operators have been instructed not to let it occur. Staff Response to TMIA Interrogatory 92. But see, ¶ 19, infra.

14. Further, reducing the subcooling margin may violate the "fuel in compression" limit, which could cause fuel rods to swell or balloon and thus block or reduce the cooling water flow between the fuel rods. The Staff acknowledges that this could occur, but rationalizes that because steam generator tube ruptures are expected to occur at cooldown, thus involving only moderate to low cladding temperatures, the affect on the fuel will be negligible. Staff Response to TMIA Interrogatory 93. This assumption relies entirely on a possibly incorrect interpretation of the original tube failure scenario. See Contention 2.a, infra.

15. As is indicated in TDR ¶ 406, Rev. 1, p. 4, the existing tube to shell delta T at TMI-1 had been 100°F. But Licensee discovered that before tube/shell delta T exceeded 100°F, the

leaking tube was placed under tensile stress and the tube was pulled into a circumferential tear. Thus, Licensee and the Staff have required operators to keep the delta T to 70°. This is a clear safety measure meant to eliminate the tension or load on the tubes in the event of a transient which could result in tube breakage. However, the NRC has no instrumentation requirements to measure delta T because the Staff claims such instrumentation is not safety related. See, Staff Response to TMIA Interrogatory 93. Thus, there is currently no assurance that Licensee's equipment for such measurements, if they have any at all, is reliable.

16. Second, there is no requirement that the plant computer be operable during plant operation. The Staff asserts that if computer capability does not exist, it is sufficient if the operators rely on estimations of delta T based on past cooldown rates. Id. Further, the Staff indicated that it really does not know what the effect maintaining delta T at 70° will be on total cooldown time, but is hoping it will be small. Staff Response to TMIA Interrogatory 94.

17. Third, as the Staff admits, maintaining the delta T at 70° depends squarely on the ability of operators to precisely modulate the controls. Thus, their training is crucial. See, Staff Response to TMIA Interrogatory 95.

18. Clearly, considering that these particular types of accidents depend upon the operators to precisely respond, they must not only have complete information, which is questionable ¶ 16, supra.

19. But the operators must be extremely well-trained. Yet at p. 21 of the most recent TDR 406, a "comment" indicates that operators who were being trained in the use of the revised guidelines found the training to be of "dubious value" and B&W would not endorse the material. This raises extremely serious safety concerns when considering the environmental contamination which is risked in the event of a simultaneous tube rupture.

Again, TMIA has confronted us with a long list in which assertions, discussions, and pleadings are intermixed.

The Licensee argues that the NRC design basis accident for steam generator tube rupture is a double-ended break of a single tube, and that no plant licensed by the NRC is required to analyze for the consequences of simultaneous tube ruptures involving both steam generators. (Licensee's arguments, at 11). The Licensee also argues that there is no increased likelihood of such simultaneous tube rupture as a result of the repair process. (Id., at 12).

The Staff argues that the Shewmon memorandum is concerned only with the issue of which tubes must be plugged. (Staff Motion, at 7). We agree with TMIA that this is a misinterpretation. The memorandum discusses two issues, i.e., plugging, and tube break in both steam generators at the same time. However, the central issue is whether the repair process has increased the probability of such an accident. Although TMIA has not shown specifically how this might be possible, the Licensee and Staff have not established the absence of a possible relationship. In particular, we reject the concept that the design basis for a new plant, constructed using new materials, is necessarily relevant to re-start after extensive and uncommon repairs.

Additional arguments are concerned with the adequacy of emergency procedures and the possibility of attaining uncoolable conditions. We accept the Staff's position on these issues.

The motions for summary disposition of TMIA's Contention 1.b are partially denied, but only to the extent that evidence is requested to be presented on the probability of simultaneous tube ruptures involving both TMI-1 steam generators. In all other respects, the motions for summary disposition are granted.

TMIA Contention 1.c[3]

> The kinetic expansion repair weakened the tubes. As a result the plugs will not be able to hold and give a good seal, and thus the plant's ability to respond to transients and accidents will be adversely affected.

In support of its Motion for Summary Disposition, the Licensee appended the affidavit of Branch Elam, Jr., Manager of its Mechanical Components Section, Engineering and Design Department, and his professional qualifications. We are satisfied that Mr. Elam is qualified to attest to the matters in his affidavit. The Licensee's statement of material facts, based on the Elam Affidavit, lists the following material facts as to which it asserts there is no genuine issue to be heard:

> 72-73. Three types of plugs have been used in the upper tubesheet area following kinetic expansion. The first type, a Westinghouse roll plug, is a hollow, cylindrical plug which is inserted in the tube and expanded against the existing tube wall. The expansion contact occurs in the region of the original tube-to-tubesheet mechanical roll and is produced by mechanically rolling the plug to achieve an interference fit with the tube.
>
> 74. The roll plug design had been previously qualified by Westinghouse for use in operating PWR steam generators. The qualification program was supplemented by a specific test program for application to the TMI-1 steam generators, which specifically qualified the plugs for leakage and plug retention capability for both normal operating and accident conditions.
>
> 76. Following the kinetic expansion, many of the tube ends extending above the top of the tubesheet and the seal welds, where most of the cracking had occurred, were damaged. However, for roll plugs, qualification is based on engagement of the original rolled portion of the tube below the seal weld, and no reliance is placed

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3 As revised in the unpublished Memorandum and Order of January 9, 1984.

on engagement of the tube ends above the seal weld. Furthermore, prior to plugging, the tube ends were machined off to the top of the seal weld.

77-78. The only portion of the tube of relevance to plugging integrity is the originally rolled portion against which the plug is rolled. The effect of the kinetic expansion on this portion of the tube was to press the already rolled tube harder against the tube sheet. This would not "weaken" the tube or adversely affect the plug retention or leak tightness capability of the engaged portion of the tube.

80-82. Most of the cracking stopped just below the seal weld before the rolled portion of the tubes began, and hence would not be in the area engaged by the plug. Some cracks were also found at a lower elevation, within the tube rolled region. These cracks were circumferential and of a tight nature, with no evidence of inter granular "branching," i.e., the cracks represented single fracture surfaces. There was no general condition of IGSAC identified in the rolled region.

83. The existence of circumferential cracks in the plug engagement region of the tube has a negligible effect on plug performance. Plug retention capability is proportional to the host area engaged, irrespective of discontinuities, since the plug engages the tube both above and below the crack. The slight decrease in surface area due to the surface area of the crack is insignificant compared to the engagement area. This was confirmed in the qualification test programs which included a test specimen with a 360° through-wall circumferential cut in the tube wall.

84. Leak tightness of the installed plugs installed in leaking tubes was demonstrated by extensive cold and hot post repair leak testing programs which demonstrated that the kinetic expansion repair did not weaken the tubes, and had no adverse affect on the capability of the roll plugs to hold and give a good seal.

85-88. The other two types of plugs installed in the kinetically expanded tubes are B&W weld plugs. The welded nail head plug is designed to be welded to the original tube-to-tubesheet seal weld, after removal of the damaged tube end by machining. The welded taper plug is welded to the tube sheet cladding at locations where a portion of the tube has been removed for examination or testing. Since neither is bonded to the tube itself, the condition of the expanded tube is irrelevant to the performance of the plugs.

89-91. Neither the seal weld nor the tube sheet cladding was affected by the kinetic expansion process. The kinetic expansion forces are far below those necessary to disturb either the seal weld or the tubesheet cladding. No evidence of seal weld or cladding damage was found during post-expansion strain gauge testing, post-installation QA weld inspections, or the subsequent hot and cold leak test programs.

In support of its Motion, the Staff appended the joint affidavit of two NRC registered engineers -- Louis Frank and Conrad McCracken, who have been previously identified. After reading their professional qualifications, we are satisfied that these two individuals are qualified to attest to the matters in the affidavit. The Staff's statement of material facts, based upon the joint affidavit and upon NUREG-1019, lists certain material facts as to which it asserts there is no genuine issue to be heard amongst which are the following:

5. At TMI-1, 23 leaking plugs were detected during the initial leak test, out of a total of approximately 2,500 which exist in the two OTSG's. This percentage of leaking plugs is not unusual for typical plugging operations which do not include kinetic expansion. These 23 plugs were repaired as necessary to ensure that technical specifications for primary to secondary leakage were maintained.

6. TMIA's concern that the kinetic expansion repair weakened the tubes is irrelevant from a technical standpoint because the plugs seal within the tubesheet and the remaining tube strength is not a factor because the tube is no longer part of the primary pressure boundary. In fact the tube can even be missing, as is the case when tubes are removed for metallurgical examination.

In its opposing response, which suffers from the same deficiencies noted above with respect to Contention 1.a, while noting that roll plugs and two types of welded plugs were installed in the kinetically expanded tubes (Response, ¶ 1 at p. 32), TMIA does not thereafter address the welded plugs and thus apparently agrees that there is no triable issue of fact with respect to them - i.e., agrees that the condition of the tube has nothing to do with the integrity of welded plugs, because these plugs are not attached to the tubes. (See Licensee's statement of material fact No. 85-88 as to which there is no triable issue, supra). With respect to the roll plugs, TMIA first relies upon written comments by Dr. Sih and upon his written statement before a Senate Committee. (TMIA Response, attchs. 2, 4). Therein, Dr. Sih opined a) that it is well-known that increase in hardness results in reduction in toughness, and b) that it is questionable whether the kinetic expansion repair process could restore the tubes to their original condition, and that, if the hardness of the tube is increased, the resistance of the material to cracking measured by the fracture toughness is likely to drop. While Dr. Sih is qualified to attest to the matters in his affidavit which references attachments 2 and 4, he does not address plugging of the tubes and TMIA does not establish any relationship between his attestations and the contention. Second, TMIA urges that there is an inconsistency between the Licensee's material facts (Nos. 80-83 supra) as to which there is no genuine issue to be heard and the Licensee's response to Interrogatory 35. (TMIA Response, p. 33). There is no inconsistency because that portion of the interrogatory relied upon by TMIA speaks to tubes that were weld plugged and not to tubes that were roll plugged. Third, TMIA states that the Licensee's Topical Design Report-008 of September 28, 1983 reflects that, after kinetic repair, both axial and circumferential cracks were found above the seal weld and that some cracks extended through the tubing behind the weld to the tubing below. (TMIA Response, p. 34). However, as the Licensee points out, these references are not relevant to roll plug performance because these conditions were found to exist only above the tube roll region. (See Licensee's statement of material fact No. 76 as to which there is no genuine issue to be heard, supra). Fourth, with respect to Staff fact No. 5, supra, TMIA argues that the Staff's conclusion was devoid of any supporting data or evaluation to determine if the 23 leaking plugs (out of some 2,500 plugged tubes) may have been related to the kinetic expansion repair. (TMIA Response, p. 34). This is a quibbling, make-weight argument presented in an effort to secure a hearing upon an obviously insubstantial issue. (See Houston Lighting and Power Company (Allens Creek Nuclear Generating Station, Unit 1), ALAB-590, 11 NRC 542, 550 (1980)). Finally, with respect to Staff fact No. 6, supra, TMIA urges that it "is well recognized that plugging a tube will not arrest degradation, so if it is not stabilized, a severed plugged tube could indeed damage tubes surrounding it during operation". . . (TMIA Response, pp. 34-35). This argument is not only unsupported, it is immaterial as well both as to the question of the integrity of the plugs, and as to the kinetic expansion repair itself.

There is no genuine issue of material fact to be heard, the Licensee's and Staff's motions for summary disposition are granted, and TMIA Contention 1.c. is dismissed.

TMIA Contention 1.d

> Neither the "Report of Third Party Review of Three Mile Island, Unit 1, Steam Generator Repair" nor the Staff's Safety

Evaluation Report (NUREG 1019) are credible documents in their evaluation of the kinetic expansion repair technique, including leak tightness and load carrying capabilities, and thus can not be used as a basis for conclusion that the repairs insure safe plant operation, (1) because of the reports' inherent inconsistencies, (2) because the basic assumptions and conclusions therein rest improperly on axial symmetric stress analysis which would not be applicable to all cracks, (3) because of the failure to analyze crack resistance on the basis of toughness as opposed to hardness which has no relation to crack resistance, and (4) because of the failure to differentiate in their analysis between the effects of thermal stress on small versus large cracks.

Licensee's motion for summary disposition included as annexes separate, short and concise statements of the material facts as to which it contends that there is no genuine issue to be heard concerning stress and crack propagation analysis in the steam generator tubes (contention subparts 2, 3 and 4), as required by 10 C.F.R. 2.749(a). Those statements are supported by an affidavit executed by Mr. S. D. Leshnoff, a mechanical engineer in the Engineering Design Department of General Public Utilities (GPU). The formal training and professional experience of this affiant satisfy us as to his qualifications in the area covered by the affidavit. With respect to subpart 1, Licensee did not annex a separate, short and concise statement of the material facts as to which it contends that there is no issue to be heard and submitted no affidavit directly concerning the report's "inherent inconsistencies." It did include an affidavit by M. J. Graham, a GPU licensing engineer, describing the Third Party Review Group (TPR), outlining information supplied to it and the resulting TPR activities and reports, which is related to subpart 1 of the contention.

The Staff's motion included an annex containing separate, short and concise statements of the material facts as to which it contends that there is no issue to be heard concerning TMIA Contention 1(d). The statements were supported by a joint affidavit executed by C. E. McCracken and P. C. S. Wu, both of whom are employed by the NRC, Division of Engineering, Office of Nuclear Reactor Regulation and have qualifications that are appropriate to address the subjects discussed in their affidavit.

As noted above with respect to Contention 1.a, TMIA's response did not annex a separate, short and concise statement of material facts as to which it contends there are genuine issues to be heard, as required by 10 C.F.R. 2.749(a). Also, contrary to that section, it intermixed arguments and statements of fact.

(1) The Reports' "Inherent Inconsistencies"

This subpart of TMIA Contention 1(d) does not identify specific "inconsistencies," but in the special prehearing conference TMIA adverted to alleged differences between the Third Party Review report at page 18 and the SER (NUREG 1019) as a specific example of an inconsistency (Tr. 61) and indicated, in response to a Board question, that additional examples could be developed in time (Tr. 68). The Board was not requested to rule and did not rule in its earlier memoranda and orders whether, during the hearing, TMIA could advert to any inconsistencies other than ones addressed at the special prehearing conference (Board Memorandum and Order, dated January 9, 1984, at 6).

We now rule that inconsistencies identified by TMIA during discovery also will be accepted for consideration here.

In response to discovery requests of Staff and Licensee, TMIA has identified a total of five alleged inconsistencies:

> The TPR analysis supports the proposition that a "break before leak" under certain situations is possible and an acceptable scenario, Attachment 6 at pp. 17-18. This is not recognized in the SER, and is inconsistent with the SER conclusions.
>
> The TPR analysis recognizes that the changed strength and dimensions of the expanded tubes is an important effect, Attachment 6 at p. 15, but seems to dismiss its implications without revealing the basis for doing so. There is no evidence in the SER that this effect is recognized and analyzed.
>
> The TPR analysis recommends that tubes with less than 40% thruwall depth should be plugged. Attachment 6 at p. 6. The SER fails to discuss this recommendation, and is inconsistent with the SER conclusions.
>
> The TPR analysis finds it hard to substantiate a firm conclusion that defects below a certain size range will not propagate due to flow-induced vibrations. Attachment 6 at pp. 16-17. This is not recognized in the SER, and is inconsistent with the SER conclusions.
>
> The TPR analysis recognizes the importance of understanding the effects of multiple tube ruptures, Attachment 6 at pp. 4-5. This is not analyzed as a separate issue in the TPR itself, or in the SER.

In its motion for summary disposition, Licensee discusses each alleged inconsistency (pp. 17-26), but annexes no statement of material facts as to which there is no issue to be heard addressing this subpart of the contention, as required by 10 C.F.R. 2.749(a). Licensee's affidavit by M. J. Graham describes the Third Party Review group and its reports, which are pertinent to this subpart. The Staff motion includes six Statements of Material Facts as to which it contends that there is no genuine issue to be heard concerning the "inconsistencies." Those statements are supported by the McCracken and Wu joint affidavit, referred to earlier.

As background, Staff's affiants assert that the reviewing authority and responsibilities of the NRC and TPR are not identical, accounting for occasional differences in coverage by the SER (NUREG 1019) and TPR reports. They also state that the fact that different issues are sometimes considered in the two reports does not necessarily indicate inconsistency between them. The Staff reviewed the TPR report after completing NUREG-1019, but did not identify any issues related to public health and safety that had been raised by the TPR other than those considered by the Staff. (McCracken & Wu Affidavit ¶ 3).

Staff's affiants point out that the entire TPR report included a February 18, 1983, issuance, with appendices, and a Supplement dated May 16, 1983, that addressed and resolved comments and recommendations that had been made in the February report. They state that TMIA failed to reference the May Supplement, which was prepared by TPR after it had received additional information and data, and contend that if TMIA had used the Supplement they could have recognized that the alleged inconsistencies based on comparing the SER with the February TPR Report had been cleared up. (McCracken & Wu Affidavit ¶¶ 4-5).

TMIA, in its Response (pages 36-44), does not address those Staff statements specifically, but maintains generally that, <u>inter alia</u>, there were ". . .safety significant differences in the reports' evaluations." (¶ 2, p. 36). It then proceeds to state:

> With regard to those safety issues raised by the TPR, the Staff made a specific finding that those TPR comments were "non-safety significant," SER at p. 4, providing no clear explanation why this was so.

The section from the top of p. 4, NUREG 1019, actually reads as follows:

> In the cover memo for the May 16, 1983 supplemental report, the TPR concludes that "comments and recommendations relating to safety of the steam generator repair have been satisfactorily resolved by GPU Nuclear." Some additional comments by the TPR which the Staff has determined are not related to safety issues are being considered by the Licensee. However, resolution of these comments will not have a negative effect on public health and safety.

Other general comments that refer to inconsistencies among the reports without clearly identifying them are in TMIA's Response ¶¶ 3-7. The five specific "inconsistencies" identified by TMIA are discussed separately in the following sections.

The first alleged inconsistency cited by TMIA (see above), is addressed in Staff's Statement of Material Fact No. 11 and by McCracken & Wu Affidavit ¶ 14, which is reproduced here:

> 14. TMIA contends (in the prehearing conference and response to interrogatories) that the TPR on pgs. 17 and 18 discusses break before leak in the transition zone and that NUREG 1019 does not do so. This statement by TMIA is incorrect. In the rest of the paragraph cited by TMIA on p. 18 of the TPR report, it is stated that if such a break occurred, the tube would be restrained in the tubesheet and detected before excessive leakage occurred. NUREG 1019 at the bottom of p. 2 and top of p. 3 discusses the 2-inch defect-free region to prevent tube pullout in the event a tube is severed at the repair transition. Both statements use different words to say the same thing (complete failure of a tube at the transition zone will result in tube leakage, but not a rupture, due to the tubesheet restraint which is provided). A more detailed discussion of this topic is provided in the Affidavit of Conrad E. McCracken and Jai N. Rajan filed in support of the Staff's Motion for Summary Disposition of TMIA Contention 1.a at ¶¶ (end). Also discussed in that Affidavit is the criteria which must be met to determine that the repair is acceptable. In summary, a licensee must demonstrate that a repaired component is equal to or better than the originally licensed component.

Review of the TPR and SER sections cited by TMIA and McCracken & Wu indicate that TMIA was in error -- the matter is discussed in both the SER and TPR reports and there is no inconsistency between them in this regard.

TMIA did not address the above Staff statement directly in its Response and it is deemed to be admitted in accord with 10 C.F.R. 2.749(a). We have reviewed this portion of the subpart and all motions concerning it and conclude that there is no material fact as to which there is a genuine issue to be heard in connection with it. Accordingly, Staff's Motion for Summary Disposition of this portion of the subpart is granted.

The second alleged inconsistency (see above) states that the TPR recognizes on page 15 that the changed strength and dimensions of the expanded tubes is an important effect, but that neither the TPR report nor the SER address and analyze those changes. Actually, a review of the statement on page 15 reveals that the contention subpart does not represent accurately the statements there:

> The explosive expansion of the tubes could affect the stress levels, if the process would change the strength or some dimension of the tubes. From the information that the Review Group has received, from the reports on the qualification tests, and from the statements made in publications issued by the tube expansion contractor, the Review Group concludes that the repair process is not expected to affect significantly the stress levels in the tubes in the restart and subsequent operation periods.

Staff Statements of Material Fact Nos. 12 and 13, supported by McCracken & Wu Affidavit ¶ 15 and ¶ 16, state that the increased transition length between expanded and unexpanded portions of the tubes and shortening of the free tubing lengths between supports by about 16 inches reduced stresses in the tubes. Also, affiants cite tests (Topical Report 008, Rev. 3, Section V and Attachment No. 1 to NUREG-1019, Section 3.4) that show that tubing dimensions affecting strength of the tubes are not significantly altered. They conclude that the kinetic repair transition zone is equal to or better than the original licensing basis, making it acceptable.

Board review of pages 16-21 in the SER (NUREG-1019) and pages 6-12 of Supplement No. 1 to NUREG-1019 (Nov. 23, 1983) reveals that substantial attention was given by Staff to several aspects of stresses in the tubes after repair by kinetic expansion. This indicates that the effects of concern to TMIA were recognized and analyzed in preparation of that report.

The TMIA Response does not controvert the Staff's statements of material facts as to which there is no genuine issue to be heard and this portion of the subpart is deemed to be admitted. We have reviewed this portion of the subpart and all motions relating to it and find that there is no genuine issue to be heard here. Accordingly, Staff's Motion for Summary Disposition is granted with respect to this portion of the subpart.

The third alleged inconsistency cited by TMIA (see above) is addressed in Staff's Statement of Material Fact No. 13, supported by McCracken & Wu Affidavit ¶ 16, as being outside the scope of this proceeding. Affiants cite as the basis for that conclusion our Memorandum and Order of January 9, 1984, p. 4, rejecting portions of this contention that question decisions about plugging of tubes. We agree with Licensee's position.

TMIA (Response, p. 39) does not address Licensee's statement of material fact directly and we conclude that it is admitted.

Our further examination of the record with respect to the matter reveals that this portion of the contention subpart relies on the February, 1983, TPR report. As pointed out by the Staff, TMIA failed to reference the update of the TPR position found at p. 2 of the May, 1983, Supplement to the TPR, which considered the GPU response and stated:

> The Review Group considers the GPU Nuclear response to be satisfactory. It is noted that the indication size is substantially less than the critical crack size developed in Safety Evaluation Report 008 and thus would not present a safety risk.

Further, contrary to statements in the contention subpart and in ¶ 11 (p. 39) of TMIA's Response to Staff's Motion for Summary Disposition, Staff did not fail to discuss this matter or merely seem to go along with it. The subject was considered in some detail at pages 14-15 of the SER and pp. 4-5 of the November 23, 1983, Supplement No. 1 thereto. Incomplete or inaccurate quotations and citations of the types noted here and elsewhere in this order are not helpful and suggest, at best, sloppy work by TMIA, even after some of the omissions had been pointed out in Motions of Staff and Licensee.

We find that there is no genuine issue of material fact to be heard with respect to this portion of the contention subpart and grant summary disposition of it.

The fourth alleged inconsistency identified by TMIA (see above) is addressed in the Staff's Statements of Material Fact No. 9 and 10, supported by the McCracken & Wu joint Affidavit ¶ 12 and ¶ 13:

> 12. In Section IX.C of the Licensee's Topical Report 008, Rev. 3, the Licensee has conducted stress analyses to determine whether small cracks could propagate under conditions of mechanical loading during normal operating, transient or accident conditions. The Licensee took into consideration the flow-induced vibration load in addition to the steady axial load. Also, the frequency and displacement magnitude of flow-induced vibration was measured at TMI-2, which are directly applicable to TMI-1 OTSG tubes.
>
> 13. The Licensee has incorporated the flow-induced vibration and normal operating transients in their analyses of potential for crack propagation. In NUREG-1019, the Staff agreed with the Licensee's conclusion that cracks which are below the threshold of detectability by ECT will not mechanically propagate to failure. (NUREG-1019, p. 22). By independent analyses, the Staff consultant (NUREG-1019, Attach. 7) agree with the Staff's conclusion. The TPR also supports this position in Comments 2 and 3 on p. 5 of their May 16, 1983 report.

In the February, 1983, TPR Report (pp. 16-17), the Group expresses some reservations about the limited data base which GPU Nuclear had to use in fracture mechanics analyses that led to a conclusion that fatigue cracks in tubes subjected to flow-induced vibrations would grow at a stable rate within the tube wall and would require a time to reach the OD of the tube that would be longer than the lifetime of the OTSG. The analysis depended upon a large extrapolation of the limited data base and made it hard to substantiate a firm conclusion (p. 10). Also, they commented that the long-term corrosion tests designed to anticipate problems before their possible occurrence do not include a flow-induced vibration type of loading, which could make a significant difference once a crack is initiated.

Subsequently, in the May 16 Supplement 1, the Group modified its position as reflected in the following (p. 5):

> Since then, more data were found to help substantiate GPU's analysis, although extrapolation is still required. One of the conclusions of the most recent GPU Nuclear analysis is that flow-induced vibrations may not play any role in propagating steam generator cracks. Nevertheless, if practical, for conservatism the Review Group still suggests that the long-term corrosion tests, which are designed to anticipate problems before their occurrence in the plant, should include a simulated flow-induced vibration loading.

The Staff addresses this subject at pp. 21-22 of the SER and pp. 8-13 of the November 23, 1983, supplement thereto and, based on review of Licensee's analyses and independent Staff calculations, concluded that:

> 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 MLSB. Therefore, reasonable assurance exists that the potential for rapidly propagating failure of steam generator tubes due to flow-induced vibration is minimized.

TMIA addresses the Staff's Statement of Material Fact on this subject in ¶ 14 of its Response (p. 40) by pointing out that in its May report the TPR still feels that extrapolation is necessary and still suggests the long-term corrosion tests to simulate flow-induced vibrations (see TPR statements excerpted above). This does not controvert the Affidavit of McCracken & Wu that Staff, Licensee and TPR Group are all in agreement that the cracks below the threshold of detectability by ECT will not mechanically propagate to failure due to flow-induced vibrations.

We find that there is no genuine material issue of fact to be heard concerning this portion of the contention subpart and dismiss it.

The fifth alleged inconsistency concerns the importance of understanding the effects of multiple tube ruptures but does not identify any specific "inconsistency" between the TPR report and the SER -- it states that neither report analyzed it as a separate issue. Accordingly, it does not appear to fit within the context of this subpart of the contention, which is based on " . . . the reports' inherent inconsistencies." Nevertheless, the Board addresses the subject to determine whether any inconsistency can be identified.

The question of multiple tube ruptures is addressed in the Staff's Statement of Material Fact No. 13.c and is supported by McCracken & Wu Affidavit ¶ 16.c. The affiants state that the various documents before the Board show that the repair program has returned the steam generators to a condition equal to or better than the original licensing basis, making the probability of simultaneous tube rupture in both steam generators no greater than before the kinetic expansion repair, and that the design basis accident for all plants is a single generator tube rupture. Nevertheless, as discussed in the Affidavit of Frank Orr in support of the Staff's Motion for Summary Disposition of Contention 1.b, procedures covering multiple tube ruptures are in place at TMI-1.

In the February, 1983, TPR Report (pp. 4-5), cited by TMIA in this portion of the contention, several major safety activities that had not then neared completion remained to be resolved including, inter alia, completing the analyses of multiple tube rupture and translating that work into useable plant guidance, procedures and training. Because GPU Nuclear work in those areas had not reached the point where it could receive a final safety evaluation, the TPR Group concluded that:

> It would be premature to evaluate that when all existing GPU Nuclear plans are completed that the Third Party Review would conclude that the results will be positive and will ensure that plant operation would be without increased risk.

Subsequently, in the May, 1983, report (pp. 1-2), which was not cited in the contention, the Review Group modified its prior conclusion after reviewing revised documents describing substantial additional analyses and testing by GPU Nuclear and its contractors:

> The Review Group now concludes that, upon satisfactory completion of the entire program as defined in the safety evaluations and as augmented by GPU Nuclear comments during and subsequent to the April 12 and 13 meeting, the TMI-1 plant can be operated safely with the repaired steam generators.

In the SER (NUREG-1019, pp. 38-40), Staff reviewed operating guidelines developed by Licensee to cope with emergencies based on Steam Generator Tube Rupture. In addition to meeting requirements of the Standard Review Plan, the guidelines also address scenarios that are not within the design bases stated in SRP 15.6.3, such as multiple tube failure, and failures in both steam generators. The Staff found that the guidelines address those scenarios appropriately, in the light of experience elsewhere with failures of steam generator tubes.

TMIA responds to Staff's Motion in ¶ 9 and ¶ 10, p. 38 of TMIA Response to Licensee and Staff Motions for Summary Disposition, but does not controvert statements of the Staff or identify inconsistencies between the TPR analysis and the SER.

We find that there is no genuine issue of material fact to be heard in connection with this portion of the subpart and grant the motion for its summary disposition.

(2) Improper Use of Axial Symmetric Stress Analysis

This subpart contends that the assumptions and conclusions of the SER and TPR report ". . . rest improperly on axial symmetric stress analysis which would not be applicable to all cracks."

Licensee presents six Statements of Material Facts as to which it contends there is no genuine issue to be heard:

> 95. Many of the tubes located in the Licensee's OTSGs have suffered some degree of circumferential cracking representative of IGSAC.
>
> 96. Licensee has performed many tests and evaluations employing various analyses to document the various properties of the cracks present in the OTSG tubes.
>
> 97. The analyses for crack resistance, i.e., for the mechanical propagation of fatigue cracks in the tubes, were not a part of, and are unrelated to, the evaluation of the kinetic expansion repair technique.
>
> 98. Axial symmetric (i.e., axisymmetric) analyses were not utilized when evaluating crack propagation because cracks are not assumed to propagate in an axisymmetric manner. The use of axial symmetry in stress analysis means that the stresses on the tubes, not the crack propagation, are axisymmetric.
>
> 99. Axisymmetric analyses were only used in one structural evaluation of the tubes. This evaluation was to compute the stress increase in the transition region of the kinetic expansion joint between the expanded and non-expanded portions of the tube.

> Axisymmetric analysis was appropriate for this evaluation because stresses are uniform around the tube circumference, i.e., bending effects are negligible. This evaluation was not related to Licensee's evaluations of crack propagation.
>
> 100. All tube structural analyses performed to evaluate the effects of cracks employed asymmetric analysis for the consideration of nonuniformities in stress distribution around the circumference of the tube.

These statements are supported by an Affidavit executed by S. D. Leshnoff, a GPU mechanical engineer, whose educational background and experience appear to the Board to be adequate to qualify him to discuss the areas included in his Affidavit.

Staff presents a statement of material fact as to which it contends that there is no genuine issue to be heard, supported by the McCracken & Wu Affidavit, referred to earlier. Their Affidavit states:

> 8. Second, TMIA asserts that the assumptions and conclusions rest improperly on axial symmetric stress analysis. TMIA's only technical basis for this contention is a statement by their consultant, Dr. Sih, that "the most dangerous direction for cracks may not be in a direction normal to axial symmetric stress." (Emphasis added). (TMIA Response to Staff Interrogatory No. 20).
>
> 9. Dr. Sih's statement is in general technically correct, but is not applicable to the particular case of once through steam generator tubes which are in axial tension during operating and accident conditions. Extensive evidence exists that axial stresses are predominant. NUREG-1019, p. 1, states that the cracks are circumferential. See also Topical Report 008, Rev. 3, Introduction. Circumferential cracks are caused by axial stresses. If the stresses were asymmetrical, then longitudinal cracking would occur. Section IX.C of Topical Report 008, Rev. 3, provides detailed data on crack propagation and references to documents with supporting stress analyses. The Licensee's analysis of crack propagation is reviewed in Attachment. No. 7 to NUREG-1019, Supplement No. 1.

Four statements have been submitted by TMIA in responding to Licensee's and Staff's Motions (TMIA Response, ¶¶ 17-20, pp. 41-42). The first sentence in ¶ 18 states:

> The fact that TPR and the Staff did not use the results of the axisymmetric stress analysis for the fracture mechanics fatigue or crack analysis is irrelevant.

Thus, TMIA admits that axisymmetric analysis was not used in evaluating crack propagation, as pointed out by Licensee in ¶¶ 95-100, cited supra, and in Licensee's Reply to TMIA's Response (pp. 32-33 and 17-18 of Attach. 1 thereto). Also, TMIA's admission eliminates the basis for this subpart of the contention, quoted above.

The Board has examined the other portions of TMIA's statements (¶¶ 17-20) and Dr. Sih's affidavit pertaining thereto, and finds they do not controvert the statements of material fact of Licensee and Staff relative to this contention subpart. Furth(, in some instances, in relying on Dr. Sih's affidavit, TMIA attempts to broaden the contention impermissibly by introducing technical matters outside of its scope. Accordingly, we find that there is no genuine issue to be heard with respect to this subpart of the contention and grant the motion for summary disposition.

(3) Crack Resistance Based on Toughness vs. Hardness

This subpart of Contention 1(d) states that the Third Party Review and the SER are not credible documents ". . . because of the failure to analyze crack resistance on the basis of toughness as opposed to hardness which has no relation to crack resistance."

Licensee includes three statements of material facts as to which it alleged that there is no genuine issue to be heard, supported by the Affidavit of S. D. Leshnoff, referred to earlier:

> 101. Crack resistance was analyzed on the basis of "toughness," which was factored into the fatigue model to evaluate the effects of stress intensities on crack propagation.
>
> 102. Stress intensity is a mathematical representation of the way stresses concentrate at the crack tips when they are transmitted around the perturbation in the stress field caused by the crack. If the stress intensity is very low, the material at the crack tip can strain to accommodate the additional loading, and no crack growth occurs. The threshold stress intensity is the value below which no growth occurs. If the stress intensity is very high, the material will fracture because the material's microstructure cannot accommodate the strain. The lowest stress intensity which results in this fracturing of a material is its "fracture toughness." In general, the more ductile the material, the higher the fracture toughness.
>
> 103. Hardness, on the other hand, is not germane to a mechanical crack propagation analysis, and was not used for that purpose. A hardness test was used solely to facilitate a comparison between rolled expansion and kinetic expansion to determine relative susceptibility to IGSAC.

Staff presents one statement of material fact as to which there is no genuine issue to be heard, supported by the McCracken & Wu Affidavit, referred to earlier. The Affidavit states:

> 7. First, TMIA asserts that crack resistance has been improperly analyzed. Allegedly, the Staff analysis is based on hardness rather than toughness. TMIA's only support for this statement is that hardness is "mentioned" on page 19 of NUREG-1019. See TMIA Response to Licensee's First Set of Interrogatories, Interrogatory No. 1.d.18. This contention is technically incorrect. Nowhere in the SER is crack resistance analyzed based on hardness. The only reference to hardness is the center paragraph on p. 19 of NUREG-1019, Section C. The usage of hardness here is correctly related to residual tubing stresses at the transition zone. No reference, inference or mention of mechanical crack propagation or resistance is made.

TMIA's Responses to Licensee and Staff Motions (¶¶ 21-24, pp. 42-43) do not controvert the Statements of Material Facts by Licensee and Staff, which directly attack and refute the claim in subpart 3 of the contention to the effect that there was a ". . .failure to analyze crack resistance on the basis of toughness as opposed to hardness. . ." Further, some of the TMIA statements amount to an impermissible attempt to broaden the contention beyond its original scope. The motion for summary disposition is granted with respect to this subpart.

(4) Failure to Differentiate Between Small and Large Cracks

This subpart of the contention states that the Third Party Review and the SER are not credible documents ". . .because of the failure to differentiate in their analysis between the effects of thermal stress on small versus large cracks."

The Licensee addresses this subpart through two statements of material facts as to which it alleges that there is no genuine issue to be heard. Those statements were supported by the affidavit of S. D. Leshnoff, referred to earlier.

> 104. Licensee accounted for both large and small cracks in its propagation analysis. In evaluating crack propagation under normal and anticipated transient loadings, a spectrum of crack sizes were interacted with the tube stresses to determine the number of cycles required to propagate the crack through the tube wall. Stress intensities were calculated for partial through-wall cracks, combining components due to membrane stress, bending stress, and stresses due to internal pressure acting on the parting crack faces, including the thermally induced axial loads constituting the major part of the load cycling. The stress intensity was recalculated for each cycle and the increment of crack growth determined. The new crack length was then used to determine the stress intensity of the next cycle.

105. Smaller cracks grow faster on a percentage basis (*i.e.*, growth per cycle divided by crack size) than larger cracks, if the same stress intensity is applied to both. Therefore, in analyzing the spectrum of crack sizes, stress intensity was separately calculated for each load cycle and crack size was accounted for during that cycle. Accordingly, the effect of crack size was appropriately considered in the fracture mechanics calculations relative to the effects of thermal stress.

The Staff presents one statement of material fact as to which it is contended that there is no genuine issue to be heard, supported by the Affidavit of McCracken & Wu, referred to earlier. The Affidavit states:

10. Third, TMIA asserts that the assumptions and conclusions fail to differentiate between small and large cracks. TMIA's basis for this contention is a statement by their consultant, Dr. Sih, that small cracks propagate faster because more proportional energy is stored.

11. Again, Dr. Sih's statement is in general technically correct. However, it is not relevant to the actual conditions within the OTSG. If a small crack propagates, it can propagate faster than a large crack because the stored energy is focused in a small area, but, as a small crack propagates, it becomes a bigger crack which then disperses its energy over a larger area. In either case, if a crack propagates through a tube wall, leakage will occur and be detected, resulting in a plant shutdown and examination/repair.

TMIA responds in three statements (¶¶ 25-27), p. 43 of TMIA Response), referring to comments by Dr. Sih (Attachment 2). TMIA's statements do not controvert those of Licensee which affirm that the effects of thermal stress on small versus large crack size were taken into consideration in its propagation analysis, contrary to the contention subpart, and describe in general how that was done. Also, Licensee's statement that crack propagation analysis legally was not part of, and is not germane to, evaluation of the kinetic expansion repair technique and that the subpart should be summarily dismissed for that reason (Licensee Motion, p. 31) was not controverted.

The Board has examined all of the submissions with respect to this subpart and finds no genuine issue to be heard. We grant the motions for summary disposition and dismiss this subpart of the contention.

TMIA Contention 2.a and Joint Intervenors' Contention 1(5).

TMIA Contention 2.a.

> Neither Licensee nor the NRC Staff has demonstrated that the corrosion which damaged the steam generator and other RCS components and systems will not reinitiate during plant operation and rapidly progress, attacking either the steam generator or elsewhere in the primary pressure boundary, thus providing no reasonable assurance that the operation of TMI-1 with the as-repaired steam generator can be conducted without endangering the health and safety of the public for the following reasons:[4]
>
> (a) There is no assurance that the causative agent or the source of initiation or the conditions under which initiation originally occurred have been properly identified, thus undermining any conclusion that the causative agent has been removed from the system, and undermining the reliability of any proposed clean-up process, procedures meant to eliminate the corrosive environment, or the reliability of the Licensee and staff stress analysis as to when corrosion could reoccur.

Joint Intervenors' Contention 1(5).

> There is no assurance that the steam generator tube repair program can assure the integrity of the tubes and their joints under the environmental conditions attendant to operation. TMI-1 shall not be permitted to restart before such assurance is provided. The following elements of the repair program are deficient:

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4 This introductory wording of TMIA Contention 2 will not be reiterated with respect to its other subparts.

*****

> (5) The possible effects of potential stress cracking agents other than active forms of sulfur have not been studied in relation to the initiation of IGSCC.
>
> - Synergistic effects have not been considered.
>
> - Third Party Review, February 18, 1983, page 9, Recommendation 1 "Carbonates in the presence of oxidants at high temperature can produce IGA and IGSCC of INCONEL 600. Other contaminants (lead, mercury, phosphorus) can also induce IGSCC."
>
> - Third Party Review, May 16, 1983, p. 3 "Further Comments" ". . . carbonaceous material was found to be the major impurity near tube failure, and may have played a role in the failure which, in our ignorance, we do not understand."

Both of these contentions assert in general that there is inadequate assurance that the specific constituents, conditions and other factors which caused the steam generator tube corrosion have been identified precisely, accurately and fully. TMIA states it in general terms and argues that without such information the Licensee and Staff cannot establish reliably that conditions which led to the corrosion have been corrected or that it will not reinitiate during plant operation and endanger the health and safety of the public. Joint Intervenors point specifically to alleged failure by Licensee to give adequate consideration to synergistic effects and to possible effects of carbonates, lead, mercury and phosphorus.

In response to Board questions in the prehearing conference, TMIA stated that it was not claiming that an error had been made by Licensee and Staff. Its concern was that a full and accurate development of the matter had not been made and that there were inconsistencies between the

SER and reports of Staff consultants. (Tr. pp. 71-76 and 83-84). In its responses to Staff and Licensee interrogatories, TMIA referred more specifically to statements on pages 7-8 of the SER that sodium thiosulfate was the contaminant that most likely caused the corrosion, but that the Staff later stated on page 8 that the failure scenario had not been clearly established. TMIA also identified specific areas of reports by Staff consultants Dillon and MacDonald which it contended raised questions that were inadequately considered by the Staff in preparing the SER.

TMIA did not attempt to identify alternative corrosion causes or specific reasons for contending that they might exist. It reiterated that the problem is that the Licensee, NRC Staff, and their consultants have not provided the detailed data and analysis that would be required to demonstrate that there is reasonable assurance that the causative agent, the source of initiation, or the conditions under which the initiation or the IGSCC originally occurred have been properly identified. It summarized its position by stating that "It is this failure to demonstrate 'reasonable assurance' through a lack of sufficiently detailed analysis and well-supported conclusions, which forms the basis for this contention." (TMIA Response to Licensee Interrogatories, January 4, 1984, pp. 24-30; TMIA's Response to Licensee's Second Set of Interrogatories and Request for Production of Documents, February 18, 1984, pp. 12-16; TMIA Response to First Set of NRC Interrogatories, January 16, 1984, pp. 9-10).

In its responses to Staff and Licensee interrogatories, Joint Intervenors identified as ". . . potential stress cracking agents other than active forms of sulfur . . ." which have not been studied and should be: low valence carbon, heretofore unidentified agents and synergists, sulfur contaminants in the INCONEL 600, and other contaminants (lead, mercury and phosphorus). Several responses stated that answers to interrogatories were unknown by Joint Intervenors and that they were unknown to Licensee and Staff, as well, but should be determined through experimentation (Lee, et al., Responses to Staff Interrogatories, January 16, 1984, pp. 1-2; Lee, et al., Responses to Licensee's First Set of Interrogatories, January 16, 1984, pp. 3-5).

Licensee's Motion for Summary Disposition of both of these contentions included 67 separate, short and concise statements of the material facts as to which it contends that there is no genuine issue to be heard concerning these two contentions, as required by 10 C.F.R. 2.749(a). The statements are supported by an affidavit (148 paragraphs) executed by Mr. F. Scott Giacobbe, Manager of Materials Engineering and Failure Analysis for GPU, whose training and experience satisfy us as to his qualifications to testify in the area of his affidavit.

Licensee's first statement of material facts dealing with this contention states:

> 106. Subsequent to the discovery of leakage in the TMI-1 once-through steam generator (OTSG) tubing, Licensee developed and implemented an elaborate series of evaluation programs to identify the extent and cause of tube failure.

Statement of material fact No. 111 describes the three conditions which must be present for IGSAC to occur:

> First, the material must be in an environment which contains a chemical specie(s) (causative agent) that will cause this type of crack. Second, the material must have a tensile stress applied to it. Third, the material under consideration must be susceptible to this type of environment.

In response to the above summary of conditions necessary for IGSAC and the areas addressed by the two contentions, Licensee described its series of evaluation programs, dividing its Statements of Material Facts into the following subject areas:

1. Characterization of the Failure Mechanism
2. Detailed Investigations of the Conditions Which Could Have Caused the IGSAC
   (a) Aggressive Environment
   (b) Stress
   (c) Material
3. Literature Review
4. Failure Scenario
5. Confirmatory Testing
6. Role of Other Potential Causative Agents
   (a) Carbon
   (b) Chloride
   (c) Other Elements
   (d) Possible Synergistic Reactions
   (e) Contaminants Introduced During Repair
7. Other Issues Discussed in Consultant's Reports

Within the above subject areas, Licensee's Statements of Material Fact summarized tne evidence that had been compiled by itself, its consultants, and others, leading to conclusions concerning: (a) the probable mechanisms of attack, (b) environmental and other conditions that contributed to the corrosion, (c) the analyses of tubes, films and water samples to identify constituents present and their probable significance in the corrosion reactions, (d) stress conditions in the tubes at various times in the operating cycles, (e) the role of active sulfur compounds in the corrosive attack, (f) the reasons for discounting effects of other constituents in the attack, (g) the reasons for discounting action of synergistic agents in the attack, (h) the rationale behind the future control program for operating the system to assure against repetition of the corrosive attack, (i) safety features and monitoring actions built into the program, and (j) the findings of others concerning corrosion in operating plants, as reported in the literature. Based on this information, Licensee and its consultants constructed a probable failure scenario to describe how and why the corrosion occurred. It then decribed confirmatory testing conducted by B&W and Oak Ridge Laboratories to test the proposed scenario and rule out other possible explanations for the attack.

The Staff's motion for summary disposition of TMIA Contention 2.a contains 10 statements of the material facts as to which it contends that there is no issue to be heard, supported by a joint affidavit (12 paragraphs) of Conrad E. McCracken and Stanley Kirslis. Both of them are employed by the NRC, Division of Engineering Office of Nuclear Reactor Regulation and have training and experience that satisfy us as to their qualifications relative to their testimony.

Staff's motion for summary disposition of Joint Intervenors' Contention 1(5) contains 24 statements of the material facts as to which it contends that there is no issue to be heard, supported by an affidavit (25 paragraphs) by Conrad E. McCracken and Paul C. S. Wu. Both of them are employed by the NRC, Division of Engineering, Office of

Nuclear Reactor Regulation and have training and experience that satisfy us as to their qualifications relative to their testimony.

The matter of identifying the causative agent of the corrosion is addressed in similar fashion in both Staff motions, illustrated by statement of material fact No. 2 from the motion for summary disposition of TMIA Contention 2.a:

> 2. Extensive tests have been conducted which have clearly identified the causative agent as a reduced sulfur species. This is stated in numerous sections of NUREG-1019, its attachments and Topical Report 008, Rev. 8 and its references (see Topical Report 008, Rev. 3, p. 10, ¶ f; NUREG-1019, Section 3.1, p. 6, ¶ d, p. 8 Conclusion, p. 29, last ¶, Attachment No. 2, p. 9, Attachment No. 3, p. 11, 2nd ¶ , last sentence. Attachment No. 4, p. 26, ¶ i, ii, iii). These tests consisted of removal and examination of sections from 29 tubes from the TMI-OTSGs, which showed the presence of sulfur on crack surfaces and the absence of other corrosion-causing contaminant, analyses of liquid samples from many plant systems and laboratory tests which simulated plant conditions and verified that a reduced sulfur species can cause the type of SCC observed. Therefore, reasonable assurances have been provided that the causative agent which initiated the corrosion has been identified.

In other statements of material fact, the Staff addressed specific statements in which TMIA contended that the Licensee and Staff activities had been inadequate; for example:

> 3. TMIA's contention that p. 8 of NUREG-1019 states "that the failure scenario has not been clearly established" (cite) is taken out of context. The full quote states:
>
>> The specific mechanistic steps involved in the sulfur-induced stress corrosion cracking phenomenon have not been clearly established; however, the fact that thiosulfate, like tetrathionate, can cause IGSCC of sensitized stainless steels has been well recognized and investigated since the 1950's, and furthermore, experimental results obtained by the licensee and the staff consultant indicate that the TMI-1 steam generator tubing specimens cracked in borated aqueous solutions at room temperature with thiosulfate concentration as little as one ppm. Therefore we conclude that

sulfur-induced SCC is the cause of the TMI-1 OTSG tube degradation and that it occurred during the cooldown or cold shutdown after the hot functional tests. The same conclusion was stated by the staff consultants through an independent evaluation (Attachments 2-4)." (Emphasis added) (footnote omitted).

4. Further, TMIA contends that there is no assurance that the conditions under which initiation originally occurred have been properly identified. The identification of sulfur as the causation agent required a showing that at ppm levels it could indeed cause rapid SCC under the plant conditions preceding the tube failure. Therefore, extensive efforts were made to identify and verify the conditions under which corrosion initiated and propagated. The results are included in NUREG-1019, Section 3.1 and Topical Report 008, Rev. 8, Section II. All of the information obtained supports the conclusion that a reduced sulfur species was the causative agent.

6. TMIA asserts that the staff ignores Mr. Dillon's comments at page 12 of Attachment No. 3 to NUREG-1019 and rejects his suggestions at page 29 of NUREG-1019. The above two statements by TMIA are inconsistent, because they both refer to the same test, recommended on page 12 of Attachment No. 3. Therefore, the suggestion could not be both "ignored" and "rejected" at the same time.

7. In fact, the recommended test was considered on page 29 of NUREG-1019, in conjunction with the total test program, and deemed unnecessary because it represented a condition which was not applicable to plant operations. Specifically, the recommended test referred to the reactor cleaning process and suggested that a 10.0 ppm sulfate test with oxygen be conducted. The cleaning process has already been completed, with the maximum sulfate concentration reaching only 0.4 ppm (pp. 17-18 of NUREG-1019, Supplement No. 1). Therefore, the results of the cleaning process and subsequent hot functional testing have demonstrated that the recommended test was not applicable.

8. TMIA asserts that the staff doesn't deal with Dr. McDonald's comments in Attachment No. 4, pages 18-24, which state that other sulfur species must be present. Also, TMIA asserts that in Attachment No. 4 to NUREG-1019 it is stated that thiosulfate could have been introduced prior to September, 1981. Pages 18-24 of Attachment No. 4 discuss a number of aspects of sulfur chemistry, including some of the reduced sulfur species which may have been present. If one reads the last paragraph on page 25 of Attachment 4, it can be seen that the discussion on pages 18-24 was provided to support a recommendation that the

reactor coolant system be cleaned (desulfurized). At TMI-1, the reactor coolant system has been cleaned as recommended. The Staff concluded (NUREG-1019, p. 29) that there would not be adverse effects from the cleaning procedure. Therefore, the comments have been dealt with.

Staff's Statements of Material Facts concerning Joint Intervenors' Contention 1(5) that are especially pertinent to specific statements by Joint Intervenors in the contention and responses to Interrogatories are addressed in the following:

4. To provide technical basis for Contention 5, Joint Intervenors quote two statements from NUREG-1019, Attachment 6, Section B, Cause of cracking (Third Party Review Report). It is clear, when the excerpted statements are placed in context and other portions of the TPR are considered, that the TPR group believe that a reduced sulfur species was the causative agent and that adequate measures have been taken to ensure protection of public health and safety. (Affidavit, ¶ 5).

5. In their February 18, 1983 Report, at the beginning of Section B, the TPR found:

"B. Cause of Tube Cracking

Finding 1 - The Review Group is in agreement with the failure scenario presented by GPU Nuclear in Section II.D.2 of the Safety Evaluation Report for return to service Appendix D, Item 17.9.

The probable mechanism for the tube cracking was IGSCC or possibly stress-assisted intergranular attack (IGA) resulting from exposure of the tube ID to sulfur and its lower oxidation states during cold shutdown with the reactor coolant system partially drained. The most plausible input corrodants were sodium thiosulfate which probably lea[k]ed from the containment spray system into the reactor coolant system during extended shutdown and oxygen which was presented in the gas phase of the partially drained reactor coolant system."

6. Additionally, in Supplement No. 1 dated May 16, 1983, the TPR states:

> "B. Cause of Tube Cracking
>
> Recommendation 1 - The Review Group had recommended earlier that GPU Nuclear implement corrective measures or verify their current programs for minimizing the ingress of all impurities (not just sulfur) into the reactor coolant system. The response addressed actions to protect from impurities. Although the GPU Nuclear actions are considered adequate for safety, the Review Group made the following comments concerning impurity control and related chemistry program. (Emphasis Added).
>
> Further Comment 3 - Control of Organics Input - Make-up water analyses presently specified will not detect organics. These materials can contain sulfur, chlorine and other aggressive impurities which will be released to reactor coolant under heat and radiation. Also, carbonaceous material was found to be the major impurity near tube failure, and may have played a role in the failure which, in our ignorance, we do not understand. For these reasons, we recommend that specific analyses for organics be performed on the make-up water and other input streams to the reactor coolant system. GPU Nuclear indicated that they were in the process of purchasing a total Organic Carbon (TOC) analyzer. This purchase should be expedited and analysis for TOC should be added to the Impurity Ingress Control Program. An initial guideline of 1 ppm TOC was suggested."

7. The above statements in paragraphs 5-6 make it clear that the TPR Group believes a reduced sulfur species was the causative agent and that adequate measures have been taken to ensure protection of public health and safety.

8. In response to Interrogatories, Joint Intervenors state they are concerned about "heretofore unidentified synergists or unevaluated agents." These undefinable agents would have been identified by the analysis program which is summarized under (1.) on page 9 of Topical Report 008, Rev. 3. These analyses clearly established the presence of sulfur in the coolant and on crack surfaces. Additionally, they established the absence of other contaminants, such as, but not limited to lead, mercury and phosphorus. The only other substance identified which has been associated with IGSCC of INCONEL 600 is carbon, which by itself is an inert material. In instances where it has been associated with corrosion it was initially present as carbonates.

9. Joint Intervenors cite the following from the Third Party Review, February 18, 1983, page 9, Recommendation 1: "Carbonates in the presence of oxidants at high temperature can produce IGA and IGSCC of INCONEL 600. Other contaminants (lead, mercury, phosphorus) can also induce IGSCC:" Third Party Review, May 16, 1983, page 3, "further Comments:" ". . . carbonaceous material was found to be the major impurity near tube failure, and may have played a role in the failure which, in our ignorance, we do not understand."

10. In a failure analysis it is not unusual to find one or more contaminants which are capable of causing the observed corrosion. Under these circumstances, a final identification of the causative agent is predicated not only on the contaminant(s) found, but the pysical conditions which accompanied the corrosion.

11. At TMI-1, only two contaminants were found which could have been associated with the corrosion of INCONEL 600. These two contaminants are carbon and reduced sulfur species.

16. Carbonates have been shown to cause IGSCC of INCONEL 600 at temperatures of 550°F, in the presence of oxidants, when concentrated in sludge piles due to a high temperature boiling process. At low temperatures this corrosion mechanism is not possible because the thermal driving force is nonexistent as is the boiling concentration mechanism. Additionally, this process takes months or years to result in through wall corrosion.

17. The Staff has concluded that it was physically impossible for carbonates to have caused the corrosion at TMI-1 because when the plant was at high temperatures: 1) Oxidants were not present, a reducing environment existed in the RCS; 2) No sludge piles or concentration mechanism existed because boiling cannot occur on the primary side of the OTSG tubes; and 3) Sufficient time did not exist to account for the observed corrosion. Moreover, this is a high temperature corrosion mechanism and all of the damage would have had to take place prior to shutdown and cooldown. Obviously, this was not the case because no leaks were detected while the plant was at full temperature and pressure. NUREG-1019, p. 1, ¶ 1.

18. The second possible contaminant, reduced sulfur species, has been shown to cause corrosion of INCONEL 600 at low temperatures, and low concentrations in the presence of oxidants.

19. A reduced sulfur species is the causative agent, because: 1) the corrosion occurred at low temperature; 2) sulfur was present

at concentrations high enough to cause the IGSCC; 3) oxidants were introduced during the cooldown and when cold; 4) the mechanism was duplicated and verified in laboratory tests.

21. Therefore, clear and substantive information exists that the causative agent has been properly identified.

TMIA's response to Licensee and Staff motions includes 18 paragraphs which are a mixture of argument, statements of fact, reiteration and amplification of points made in the original contention and responses to interrogatories, and additional statements on subjects not discussed earlier. It does not controvert Licensee and Staff statements of facts and contains no separate, short and concise statements of material facts as to which it contends there are genuine issues to be heard. Joint Intervenors' response also does not controvert Licensee and Staff statements of fact and contains no separate, short and concise statements of material facts as to which it contends there are genuine issues to be heard. It includes arguments and restatements of points that had been made earlier in its contention and responses to interrogatories, as well as subjects not advanced earlier and not dealing with the contention directly. Moreover, neither Intervenor included affidavits supporting its statements made in opposition to the motions of Licensee and Staff, which were supported by affidavits.

Under these circumstances, pursuant to 10 C.F.R. § 2.749, we conclude that there is no genuine issue of material fact that need be heard. Accordingly, the motions for summary disposition are granted and TMIA Contention 2.a and Joint Intervenors' Contention 1(5) are dismissed.

TMIA Contention 2.b.1.

> The Staff's own consultant on this issue, R. L. Dillon, believes that the risk associated with cleaning, i.e., that a relatively large inventory of sulfur compounds will be put into solution, are greater than simply "living with large S inventory in the system," supporting a conclusion that the only two possibilities being considered by the Licensee and Staff pose substantial risk that corrosion will reinitiate.

In support of its Motion for Summary Disposition, the Licensee appended the affidavit of F. Scott Giacobbe (cited in connection with TMIA Contention 2a, supra). The Licensee's Statement of Material Facts, based on the Giacobbe affidavit, includes the following material facts as to which the Licensee asserts that there is no genuine issue to be heard:

> 173-174. The concerns relating to cleaning expressed by Staff consultant R. L. Dillon and by the TPR were expressed prior to the cleaning. Prior to the decision to remove residual sulfides from the tube surfaces by a hydrogen peroxide cleaning process Licensee gave careful consideration to any risks the process might have on recurrence of tube damage induced by sulfur or the peroxide cleaning process. Short and long term corrosion testing confirmed the safety of the process.
>
> 175-177. The cleaning process used low levels of hydrogen peroxide to rapidly convert the insoluble reduced sulfide left on the tube surfaces to an oxidized soluble form (sulfate) under protective, high pH conditions. It took approximately 400 hours. The cleaning has successfully been completed, with no adverse effects on the RCS. The sulfate concentration never exceeded 0.4 ppm, and no damage was detected in the system as confirmed by hot functional testing of the OTSGs after the cleaning process was completed. In light of the successful completion of the cleaning, the concerns expressed by Mr. Dillon and others have no bearing on the TMI-1 restart.
>
> 189-190. Dillon's pre-cleaning reservations as to the hydrogen peroxide process were based on estimates that 5-10 ppm of sulfur compounds would be put into solution. Even with his estimate, Dillon viewed the risks as too small to preclude restart. The Third Party Review Group concluded that peroxide flushing was not expected to have an adverse impact on plant safety. The TPR

recognized there was some risk with cleaning, but viewed the risk as inconsequential.

In support of its motion, the Staff appended the joint affidavit of Conrad E. McCracken and Dr. Stanley Kirslis. Previously, we have evaluated these affiants' professional qualifications, and we find them qualified to attest to the matters in the affidavit. The Staff's Statement of Material Facts, based on this joint affidavit, consists of the following material facts as to which the Staff asserts that there is no genuine issue to be heard:

2-3. In support of this contention TMIA references Mr. Dillon's technical evaluation report (NUREG-1019, Attachment No. 3). At no place in Attachment No. 3 does Mr. Dillon state that he believes a substantial risk exists either in cleaning the sulfur from system surfaces or in leaving it on. Conversely, on pages 12 and 13 of Attachment 3 Mr. Dillon presents the pros and cons of cleaning, concluding on page 14 that "I am not strongly pro or con." In the first full paragraph on page 13, Mr. Dillon focuses on his primary concern with cleaning. "The level could reach 5-10 ppm of sulfate. In the presence of oxygen and of a high temperature, this is a good recipe for SCC of sensitized stainless steel. At 130°F there is no SCC data known to me."

4-5. Subsequent to the completion of Mr. Dillon's report, a decision was made to clean the reactor coolant system. The decision, in part, reflected Mr. Dillon's concerns because if the potential, even though remote, existed for re-initiation of corrosion, then it was better from a public health and safety point of view to have it initiate during a cleaning process with the reactor shutdown. Additionally, Staff consultant Dr. McDonald at page 25 of Attachment No. 4 to NUREG-1019 concluded that cleaning was necessary. Therefore, in consideration of public health and safety, cleaning was the conservative approach. The cleaning results are provided by Topical Report 008, Rev. 3, Section IV.D. and NUREG-1019, Supplement No. 1, pg. 16, 17 and 18. In summary, the maximum RCS sulfate concentration reached was 0.4ppm, an order of magnitude below that which Mr. Dillon addressed.

6. Subsequent to the cleaning process, a full temperature and pressure hot functional test of the entire reactor coolant system and steam generators was conducted and no evidence of corrosion reinitiation was detected as evidenced by the low primary-to-

secondary leakage (NUREG-1019, Supplement No. 1, pg. 22). Therefore, no technical basis has been provided by TMIA in support of Contention 2.b.1.

In its response opposing the motions for summary disposition, TMIA submitted the following statements:

1. TMIA Contention 2.b.1 alleges that concerns raised by Staff consultant Dillon regarding the risk of further corrosion from the cleaning process itself have not been conclusively resolved.

2. Licensee first asserts that the results of its long term corrosion testing assures that no damage resulted from the cleaning process. (Licensee Facts ¶ 174, 178-81). As already discussed in the context of qualification testing, TMIA Contention 1.a, ¶ 8 et seq., supra, there are significant questions regarding the accuracy of such tests. Further, Staff consultant MacDonald criticized the accuracy of testing being conducted by Licensee. (MacDonald at p. 15; Attach. 4 to SER).

3. Licensee further claims that Dillon's concerns are now moot because hot functional testing and low leakage has proven the cleaning process was successful, and no adverse effects or damage was detected. Licensee Facts § 176. Deficiencies in these types of tests have also been discussed and documented, supra. See, TMIA Contention 1.a, ¶ 64 et seq.

4. In any event, neither Licensee nor the Staff have supplied any first hand indication from Dillon himself whether or not he is now satisfied the tubes were not damaged as a result of the cleaning process, particularly whether he is satisfied with the post cleaning testing which was done. Absent this, the genuine material issue of fact originally raised by Dillon is still open.

The Board accepts the explanations of the Licensee and the Staff that the concerns expressed by the Staff's consultants Dillon and MacDonald were adequately taken into account, along with many other considerations, in making the decision to clean the primary coolant system. It may be noted that the wording of the contention is an overstatement; the language used by Mr. Dillon (NUREG-1019, Attach. 3, p. 12) was:

> There are risks associated with the sulfur oxidation and removal as well as the alternative of living with a large S inventory in the system.

The Board has reviewed the submissions of all parties with respect to Contention 2.b.1 and concludes that there is no genuine issue of material fact to be heard. Accordingly, the motions for summary dispositions are granted, and this contention is dismissed.

TMIA Contention 2.b.2 and Joint Intervenors Contention 1(2).

TMIA Contention 2.b.2.

> Even if the proposed cleaning process presented no risks, there is no assurance that the proposed process can remove more than 50-80% of the contamination, thus there can be no assurance that the contamination which would be left after the process is complete will not cause reinitiation.

Joint Intervenors' Contention 1(2).

> There is no assurance that the steam generator tube repair program can assure the integrity of the tubes and their joints under the environmental conditions attendant to operation. TMI-1 shall not be permitted to restart before such assurance is provided. The following elements of the repair program are deficient:
>
> *****
>
> (2) Active forms of sulfur can be generated from presumably benign sulfur remaining on the tubes after cleaning.
>
> - Attachment 3 to SER. p. 6, 3rd Para "If it has not been shown that SCC does occur in low temperature solutions, neither has it been shown that it does not."
>
> - Third Party Review, May 16, 1983, p. 5, last sentence 2nd para. ". . . There was (and is) no quantitative measure of the potential for reactivation."

Both contentions are based on concern that the corrosion will reinitiate during plant operation. TMIA bases its contention on the observation that only 50-80% of the sulfur will be removed from the system during the proposed cleanup and that sulfur remaining in the system thereafter could cause reinitiation of corrosion. Further, in its answers to Licensee's interrogatories, TMIA expressed concern about failure of Licensee to flush piping and components of less than one inch in diameter, as described in the SER Supplement 1 at page 14. TMIA states that it is the failure of Licensee and Staff to provide detailed data needed to demonstrate (a) reasonable assurance of adequacy of the post clean up testing and analysis, (b) the safety of 0.1 ppm sulfate in solution, and (c) the adequacy of Licensee's administrative controls to insure prevention of buildup of corrosive sulfur concentrations that forms the basis for this contention.

Joint Intervenors state specifically that active forms of sulfur can be generated from residual sulfur in the system after cleaning and base that contention on the two statements quoted from the SER and Third Party Review. In responses to Licensee's interrogatories, Joint Intervenors state that the active forms of sulfur that can be generated from sulfates and thiosulfates remaining in the system include sulfides and as yet unidentified forms that might couple synergistically with other elements or compounds to function as stress cracking agents. These compounds are visualized as being able to form through chemical reduction or ". . . other mechanisms of which we are unaware by virtue of failure of Licensee to look for them" and are alleged to be sufficient to reinitiate corrosion of the steam generator tubes. Joint Intervenors stated that it is possible that an inventory of 0.1 ppm sulfate in solution could have a significant corrosive effect, if a suitable synergist is present to increase activity and a suitable reducing agent is present to generate active forms.

Licensee's Motion for Summary Disposition addresses the two contentions together and presents 24 statements of the material facts as to which it contends that there is no genuine issue to be heard, as required by 10 C.F.R. 2.749(a). Those statements are supported by the affidavit of Mr. F. Scott Giacobbe, described in connection with TMIA Contention 2.a, supra.

The following Licensee statements summarize pertinent aspects of sulfur chemistry as background information:

> 193. Sulfur has a number of oxidation states ranging from sulfate, which is present in the reactor coolant, to sulfide, which is present in film on the tube surfaces. Neither of these two forms of sulfur is harmful to the tubes. However, intermediate species between the two extremes are aggressive, and if present in sufficient quantities, could cause reinitiation of the cracking mechanism.
>
> 194. Sulfate and sulfide are the dominant equilibrium species within the pH and temperature ranges of interest for normal reactor coolant system operation.
>
> 195. Sulfate is stable under oxidizing conditions, and therefore is the equilibrium specie at room temperature in oxygenated water at pH equal 5.
>
> 196. Sulfide, on the other hand, is the stable specie under reasonably reducing conditions, that is, normal operating conditions (deoxygenated, temperature above 250°F) and pH levels.
>
> 197. Metastable intermediate species such as thiosulfate can persist only within a very restricted pH and oxidation range.
>
> 198. Under the reducing conditions which existed in the RCS during the August-September 1981 hot functional test, the thiosulfate which contaminated the PWR primary system transformed

towards more reduced metastable species. However, during the following cooldown, oxygen was introduced into the system. The oxidating conditions in the presence of aggressive metastable sulfur species were responsible for cracking.

199. Under normal operating conditions when the primary system is deaerated and hydrogenated, nickel sulfide will remain stable, and aggressive intermediate species will not be formed. Limited quantities of nickel sulfide may, however, be slowly dissolved in the primary coolant and be removed by the ion exchange resins.

200. Oxidation of residual nickel sulfide to sulfate can occur to some extent if the primary system is cooled and oxygenated. However, control of system oxygenation during cooldown will avert this formation.

Steps that have been taken to tighten controls and prevent reinitiation of corrosion are outlined in Licensee statements 201-214 and include: (a) physical disconnection of the thiosulfate tank from the reactor coolant system, (b) stronger controls on quality and additions of chemicals used in the reactor coolant system, (c) modified limits on concentrations of sulfates, chlorides and fluoride (0.1 ppm each) in the reactor coolant system (IGSAC will not be caused by those concentrations), (d) analyses for those constitutents and conductivity at least five times per week, (e) periodic analyses for total sulfate and analyses for reduced sulfur whenever the difference between sulfate and total sulfur suggest that intermediates may be present, (e) raising the lithium concentration to 1-2 ppm. the highest concentrations allowed, (f) improvement in sensitivity of analyses for sulfate to 0.03 ppm, (g) initiating total organic carbon analyses, and (h) continued removal of sulfur compounds and other ionic species by ion exchange to prevent buildup of contaminants.

Licensee contends that the control procedures for reactor coolant conditions will minimize conversion of sulfide surface films to potentially harmful intermediate species by preventing the combination of temperature and oxidizing conditions necessary to form them. During cooldown, the control procedures require maintenance of reducing conditions until temperature is near ambient and then blanketing by nitrogen to exclude oxygen. These controls and routine monitoring of sulfur levels during layup will ensure that the inactive sulfides do not generate active species in quantities sufficient to harm the OTSGs.

Addressing the matter raised by both Intervenors concerning the corrosion potential of 0.1 ppm sulfate in the system, the following statements are made:

> 217. Short term tests using TMI-1 OTSG tubes samples, some of which had been exposed to the cleaning process and thus were representative of the tubes in use, verified that corrosion will not reinitiate at up to 1 ppm sulfur species.
>
> 223. Sulfate is a potential corrodant only at high concentrations; the levels specified for normal reactor chemistry are not aggressive to INCONEL 600 tubing. This was confirmed by the short and long term corrosion tests in which no IGSAC was detected.
>
> 224. Sulfate corrosion has only been observed in high temperature, high concentration acide sulfate solution under highly stressed conditions.

TMIA's concern about the failure of Licensee to flush small piping during the cleaning process is the subject of statement of fact No. 222:

> 222. Piping less than 1 inch in diameter was not flushed as part of the hydrogen peroxide cleaning process. The surface areas of these lines is small relative to the balance of the reactor coolant system, representing less than 5% of the surface area of the RCS. The amount of sulfur that could be transported to these lines is negligible compared to total sulfur inventory. It is

within the capacity of the reactor coolant clean up system to control.

Licensee indicates (statements 220-221) that eddy current tests and metallographic examination of C-ring specimens removed from all four test loops have shown no IGSAC and that the hot functional test performed in August and September, 1983, provided further assurance that Licensee's control scheme for preventing reinitiation of IGSAC is effective. Licensee is continuing long-term corrosion tests on actual OTSG tube samples under conditions simulating environmental and operating conditons with worst-case chemistry conditions that could exist in the primary system within technical specification limits. (statements 218-219).

The Staff's Motion for Summary Disposition of TMIA Contention 2.b.2 contains 8 statements of the material facts as to which it contends that there is no issue to be heard, supported by a joint affidavit (9 paragraphs) of Conrad E. McCracken and Stanley Kirslis, who have been identified earlier in connection with TMIA Contention 2.a, supra. Staff Motion for Summary Disposition of Joint Intervenors' Contention 1(2) contains 14 statements of the material facts as to which it contends that there is no issue to be heard, supported by another affidavit (14 paragraphs) of Conrad E. McCracken and Stanley Kirslis. We find that they are qualified to attest to the matters in their two affidavits.

In addressing the specific citations in the Joint Intervenors contention, Staff makes the following statements of fact:

2. As basis for this contention, Joint Intervenors cite to two statements, the first by a staff consultant and the second by the third party review:

- Attachment 3 to SER, p. 6, 3rd para., "If it has not been shown that SCC does occur in low temperature solutions, neither has it been shown that it does not."

- Third Party Review, May 16, 1983, page 5, last sentence, 2nd para., ". . . There was (and is) no quantitative measure of the potential for reactivation."

3. Both of these statements are taken from sections of the respective reports which are considering the potential for reactivation during the cleaning (desulfurization) process. As such, they cannot provide basis for Joint Intervenors' Contention 2, which pertains to sulfur remaining on the tubes after cleaning.

4. Both Attachment 3 and the TPR of May 16, 1983 conclude that the sulfur residual remaining on system surfaces is inactive or superficial and that continued operation is acceptable without performing a cleaning process. Therefore, while the Staff agrees that "active forms of sulfur can be generated from presumably benign sulfur remaining on the tubes after cleaning, "both NUREG-1019 and the TPR explain that it is unnecessary to completely remove the sulfur because the low levels of sulfur in solution remaining after cleaning do not have a significant corrosive effect, and that any sulfur remaining on tube surfaces after cleaning will be released so slowly that there will be more than ample time to prevent buildup of corrosive sulfur concentrations.

5. Attachment 3 to NUREG-1019 is a document by Staff consultant R. L. Dillon. It states, on page 6, paragraph 3: "Convincing argument that any special measures need to be taken to remove supe ficial sulfur is more difficult." (Emphasis added). On page 14, paragraph 2, it is explained: "I believe TMI-1 restart is appropriate. This view is confined to consideration of corrosion related factors. The likelihood of reactivation of IGSCC based on some manipulation of the sulfur inventory now fixed in or on corrosion product surfaces is small. Release of sulfur to solution from the corrosion product is slow, amounting to days or weeks even for the cleaning process. The metastable species that appear capable of initiating or sustaining cracking rections are rapidly oxidized to relatively inert species, with the result that they can only be present in the most minute quantities (ppb's or less, as a guess) -- a very different situation from the transient condition where 3-5 ppm of dissolved sulfide was suddenly oxidized during the crack initiating event.

The repetition of the sulfur contamination incident is precluded physically and administratively."

6. In Attachment No. 6 to NUREG-1019 is the Third Party Review, dated May 16, 1983 at page 5, wherein it is stated:

"The Review Group previously considered both the necessity of benefits of sulfur removal and the capability of the proposed peroxide flushing process for accomplishing sulfur removal. At that time we concluded that sulfur removal was not essential for return of the plant to power. All available information indicated that the corrosion had stopped and that sulfur residues following completion of the repair would be comparable to other plants. The primary benefit of sulfur removal was intangible; the potential for reactivation of the corrosion from these surfaces would be reduced in proportion to the degree of effectiveness of removal. However, there was (and is) no quantitative measure of the potential for reactivation. (Emphasis added).

7. At page 6, Attachment 6 continues:

The Review Group continues to believe, however, that sulfur removal is not essential for safe operation of the plant and that the costs and residual risks in uncertainty over perioxide outweigh any benefits. We believe that the corrosion process is presently passive and will remain passive with good chemistry control even though sulfur residues will be available. We note that tests show 20-50% of the sulfur will not be removed by the process, so that sulfur residues will still be available after the flush. This process will be costly in time, chemical, on exchange resins, radioactive waste generation and man-Rems. In any complicated process, upsets can occur which could result in exposure of system materials to conditions not enveloped by testing. Finally, there is much about the reactions between peroxide and system materials which is not understood, so that (in spite of testing) there remains a risk that the process could be detrimental. (Emphasis added).

We therefore believe that peroxide flushing to remove sulfur is not essential to plant safety nor is peroxide flushing expected to have an adverse effect on plant safety. (Emphasis added).

8. Therefore, the conclusion of both reports is that the likelihood of converting surface sulfur to a corrosive soluble form during reactor operation is so low that the perioxide cleaning procedures is of questionable benefit.

Statements 9-14 indicate that Licensee has carried out an extensive corrosion test program, using actual specimens from TMI-1 OTSGs under the worst permissible chemistry conditions and that none of the tests have shown reinitiation of corrosion with up to 300 days of exposure. In spite of those positive results, it was decided to clean the reactor coolant system anyway, partly because of concerns expressed by consultants Dillon and MacDonald that a remote possibility existed for reinitiation of corrosion. Low concentrations of sulfur observed during cleaning and in the hot functional testing and absence of corrosion reinitiation during the one month hot functional testing at full pressure and temperature provided additional evidence that the sulfur remaining in the system will not lead to corrosive conditions.

TMIA's and Joint Intervenors' responses to Licensee and Staff motions include mixtures of arguments, reiteration of points made earlier and addressed in detail by Licensee and Staff, and some additional statements on subjects not discussed earlier. Neither Intervenor controverts Licensee and Staff statements of fact and neither includes separate, short and concise statements of material facts as to which it contends that there are genuine issues to be heard. Neither Intervenor included affidavits supporting its statements made in opposition to the motions of Licensee and Staff, which were supported by affidavits.

The Board has examined all of the motions and supporting documents of the parties relating to these contentions and concludes that there is no genuine issue as to any material fact. Accordingly, the motions for summary disposition of TMIA Contention 2.b.2 and Joint Intervenors' Contention 1(2) are granted, and these contentions are dismissed.

TMIA Contention 2.c.[5]

> Neither the "Report of Third Party Review of Three Mile Island, Unit 1, Steam Generator Repair" nor the Staff's Safety Evaluation Report (NUREG-1019) are credible documents in their evaluation of the causative agent, clean up, or procedures to prevent contaminant reintroduction, and thus can not be used as a basis for conclusion that the repairs insure safe plant operation, because of the reports' inherent inconsistencies.

In support of its Motion for Summary Disposition, the Licensee appended the affidavit of F. Scott Giacobbe, the Manager, Materials Engineering and Failure Analysis for General Public Utilities Nuclear Corporation, and cited his affidavit in its Statement of Material Facts As To Which There Is No Genuine Issue To Be Heard. However, the Licensee's brief does not cite the Giacobbe affidavit in support of its arguments. In support of its Motion, the Staff appended the joint affidavit of Conrad McCracken and Paul Wu, and cited these two affiants in its Statement Of Material Facts As To Which There Is No Genuine Issue To Be Heard and in its arguments. Previously we have evaluated the qualifications of these three affiants, and we find them qualified to attest to the matters in the affidavits. TMIA did not respond to the motions for summary disposition. However, despite TMIA's failure to

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5 As revised in the unpublished Memorandum and Order of January 9, 1984.

respond, we must determine whether the movants have sustained their burden of proof in showing that there is no genuine issue as to any material fact and that, as a matter of law, movants are entitled to summary disposition of this contention. Cleveland Electric Illuminating Company (Perry Nuclear Power Plant, Units 1 and 2), ALAB-443, 6 NRC 741, 753-54 (1977).

While we found the Licensee's and the Staff's affidavits helpful from a technical standpoint, the disposition of the motions for summary disposition turns upon our legal and technical construction of various documents. The Licensee and the Staff assert, and we agree, that, at no time during the special prehearing conference or in responses to interrogatories, did TMIA point out even one technical inconsistency between NUREG-1019 and the attached Third Party Review Report that was within the scope of this contention. They assert that, during discovery, TMIA had levelled four criticisms at NUREG-1019 and alleged inconsistencies between that document and the Staff's consultants' reports attached thereto.

Apparently, TMIA's first criticism (advanced during the special prehearing conference at transcript pages 98-101) is that, while NUREG-1019 at pages 28 states that peroxide treatment will remove 50 to 80% of the sulfur, Staff's consultant, Mr. Dillon, at page 6 of Attachment 3 thereto, stated that 20-50% of the tubes would not be desulfurized. TMIA has misunderstood Mr. Dillon, because after reading his report, we conclude that he was merely stating that, after the desulfurization, the remaining sulfur would be 20-50% of the original concentration.

TMIA's second criticism (reflected in its first response to Licensee's interrogatories of January 4, 1984) is that, while, in NUREG-1019 at pages 7-8 the Staff concludes without any support that sodium thiosulfate at concentrations of 4-5 ppm is the contaminant which most likely caused the tube degradation, p. 8 of that document states that the failure scenario has not been clearly established and recognizes three previous contaminations which may have caused corrosion. After reading Section 3.1 of NUREG-1019, plus Attachments 2-4 and 6, we find that they fully support the Staff's conclusion that sodium thiosulfate was the contaminant which most likely caused the tube degradation. Moreover, we see no inconsistency at page 8 of NUREG-1019, which notes that "The specific mechanistic steps involved in the sulfur-induced stress corrosion cracking phenomenon have not been clearly established . . ." -- there the Staff, in appreciating that sodium thiosulfate is the contaminant, but not the corrodant, merely recognized that the precise species of sulfur created from the thiosulfate during the hot functional test period and the process itself which caused the intergranular stress assisted corrosion have not been conclusively established. While TMIA apparently contends that Staff and the Licensee have not established that sodium thiosulfate was the culprit because the SER, at pp. 5-7, Attachment 3, at p. 2 and Attachment 4, at pp. 3-5, reflect that on three previous occasions sulfur-containing species were probably introduced into the RCS and did not result in tube degradation, these documents show that the corrosion which occurred here was due to environmental conditions which had not previously been in existence--i.e., environmental conditions arising due to hot functional testing or cold shutdown.

TMIA's third criticism (reflected in its first response to Licensee's interrogatories) is that the Staff did not deal with Mr. Dillon's comments which challenged aspects of the conclusion that thiosulfate was the most likely contaminant, and rejected his suggestion that a corrosion test be conducted in a cold, high oxygen and high concentration sulfate environment. Again, after our review of Attachment 3 to NUREG-1019, we conclude that Mr. Dillon was not challenging the conclusion that sodium thiosulfate was the most likely contaminant. He was merely recognizing, as did the Staff, that the precise species of sulfur created from the thiosulfate and the process which caused the IGSAC have not been definitely established. Further, while the Staff did not agree with Mr. Dillon's suggestion, the SER at page 29 shows that the Staff did not arbitrarily and without basis refuse to accept his suggestion; it did not accept his suggestion because the Licensee had performed tests, the results of which provided reasonable assurance that no adverse effect on the reactor coolant system and tubes would occur during the chemical cleaning period.

TMIA's fourth criticism (also derived from its first response to Licensee's interrogatories) is that the Staff failed to deal with the comments of its consultant, Dr. Digby MacDonald, at pages 18-24 of his report (Attach. 4 to NUREG-1019) concerning presence of polysulfur species in the system, presence of sulfur deposits in the system, and that thiosulfate could have been introduced into the system before September 1981. Based on our review of pages 18-25 of Dr. MacDonald's report and pages 5-7 and 27-30 of the SER, we note that Dr. MacDonald is discussing mechanisms involved in development of the corrosion, leading to his conclusion that sulfur contaminants remaining in the system make it prudent to clean the system to minimize possibility of further corrosion in the future. The system actually was cleaned and we see nothing inconsistent between Dr. MacDonald's comments and Staff's position on the matters.

We find that the Licensee's and the Staff's constructions of the various documents concur with our constructions and we conclude that they have sustained their burden of showing that there is no genuine issue as to any material fact and that they are entitled, as a matter of law, to summary disposition of this contention. Accordingly, TMIA Contention 2.c is dismissed.

Joint Intervenors' Contention 1(3).

> There is no assurance that the steam generator tube repair program can assure the integrity of the tubes and their joints under the environmental conditions attendant to operation. TMI-1 shall not be permitted to restart before such assurance is provided. The following elements of the repair program are deficient:
>
> *****
>
> (3) Morphological changes in the inner tube surface, remote from the expanded joints, could reasonably be presumed to be precursors of IGSCC.

In support of its Motion for Summary Disposition, the Licensee appended the affidavit of F. Scott Giacobbe (cited in connection with

TMIA Contention 2.a and others <u>supra</u>). The Licensee's statement of material facts in connection with Joint Petitioners' Contention 1(3), based on the Giacobbe affidavit, consists of the following material facts as to which the Licensee asserts that there is no genuine issue to be heard:

225. The only morphological changes other than IGSAC that have been identified in the TMI-1 OTSG tubes consist of isolated, small areas of intergranular attack (IGA).

226. IGA is a corrosion phenomena which, like IGSAC, requires an aggressive environment as well as a susceptible material. Unlike IGSAC, however, IGA formation does not require an applied stress.

227. IGA is primarily found as a network of attack associated with a main intergranular crack. IGA can also exist as a separate form of corrosion. Conversely, IGSAC can be found in the absence of IGA.

228. It is possible that IGA could propagate into IGSAC <u>if</u> the appropriate corrodant were present and a tensile stress were applied. Even under applied stress, however, IGA cannot continue to progagate or become IGSAC in the absence of a corrodant.

229. Because sulfur and other contaminants are not now and will not be present in the future in corrosive levels, IGA will not reinitiate or progagate into IGSAC in the TMI-1 OTSGs.

230. Intergranular attack manifests itself with three levels of severity, each with a different morphology. First, the majority of the tube-observed IGA consists of only minor surface etching, a maximum of 1-2 grains deep (.001 inch). This surface IGA has been identified in the industry as an etching phenomena typical of Inconel 600 tubes and is not indicative of any increased propensity for corrosion.

231. The second type of IGA is called IGA "islands." These are small patches generally 4-5 mils in depth and 3-4 mils wide where a small network of IGA exists. The grains remain in place, although the grain boundaries have been attacked.

232. The third type of IGA is called "pitting." This is simply an IGA island from which some grains have fallen out.

233. The metallographic examination of the 29 TMI-1 tube samples demonstrates that the majority of intergranular attack is (1) located in the upper tubesheet region, and (2) associated with cracks. It also demonstrates that there is IGA without IGSAC, and IGSAC without IGA. The specific results of the examination are as stated in paragraphs 137-142 of the Giacobbe Affidavit.

234. That IGA was located primarily near cracks and in the upper tubesheet region is expected because concentration/aggressiveness of the corrodant was highest in the upper tubesheet region, particularly in the area of the cracks.

235. The magnitude of any intergranular attack is dependent on the strength of the corrodant at a particular location, the susceptibility of the material and other localized conditions.

236. No IGA islands in the freespan were found by metallurgical examination and visual examination.

237. Surface analysis of the freespan indicated that sometimes the freespan had no sulfur present; where sulfur was detected in surface film below the UTS region, concentrations were significantly lower (less than 2%) than that observed in the vicinity of cracks found within the UTS region.

238. Although some IGA islands might be found on the freespan, the number and extent are not likely to be significant, given the low level of sulfur present.

239. Examination of the effect of the IGA on the mechanical properties of the tubes by metallographic examinations and mechanical testing demonstrated that the material not directly affected by IGA or IGSAC retains its original strength and ductility.

240. Since the cross-sectional area occupied by IGA islands is very small, its presence has an insignificant affect on strength and ductility.

241. The conditions which resulted in IGA of the TMI-1 OTSG tubes did not adversely affect the tubes' mechanical properties.

242. Because the presence of a corrosive agent is necessary for the propagation of IGA, the same strategies which have been instituted to control the presence of contaminants and conditions necessary for IGSAC will also serve to prevent propagation of IGA, and to prevent IGA from propagating as IGSAC.

243. Tests performed on actual OTSG tubing have confirmed that propagation of IGA is not occurring and that the control measures will be effective. In particular, one of the objectives of the long term corrosion test was to study the influence of prolonged operation on IGA. There is no evidence of further intergranular attck or IGSAC. This is despite the fact that these samples also contain shallow surface IGA. In no cases has this IGA propagated into an intergranular stress assisted crack. IGA cannot be considered a precursor of IGSAC.

In support of its motion, the Staff appended the joint affidavit of Conrad E. McCracken and Louis Frank. Mr. McCracken was cited in connection with TMIA Contention 1.a and other contentions, and Mr. Frank was cited in connection with TMIA Contention 1.b and others. They are qualified to attest to the matters in their affidavit. The Staff's statement of material facts, based on this joint affidavit, consists of the following material facts as to which the Staff asserts that there is no genuine issue to be heard:

2. To provide technical basis for this Contention, Joint Intervenors have quoted part of a sentence: "[M]ost extensive IGA is in the vicinity of major cracks." (P. 81 of GPUN Topical Report 008, Rev. 3). The entire sentence from which this quotation is taken reads: "However, by bounding this condition with specimens containing surface IGA and actual cracks, <u>the influence of this condition can be assessed</u> especially on consideration of the fact that metallography has shown that the most extensive IGA is in the vicinity of major cracks." (Emphasis added). The preceding sentence is excerpted from Topical Report 008, Rev. 3, Section C, <u>Undetected Defects</u>, which discusses the presence of IGA, the fact that it is not unusual in steam generator tubes, as a result of the tube manufacturing process and the "lead" corrosion testing program being conducted to address IGA. (Topical Report 008, Rev. 3, pp. 25-27).

3. The "lead" corrosion test program incorporates actual tubing specimens which were removed from TMI-1 OTSGs. Tests were conducted, and are in progress, using as-removed tubing samples and samples which were cleaned using the peroxide process. Chemistry conditions duplicate those anticipated during plant operation. Chemistry conditions are maintained at the maximum limits to simulate worst case conditions, including 0.1 ppm sulfate. None of

these tests have shown reinitiation of corrosion, with up to 300 days exposure as of December 1983. Docketed letter by Licensee dated January 31, 1984.

4. Additionally, no evidence of corrosion reinitiation has been detected in the plant. This is verified by the steam generator hot functional tests, during which full temperature and pressure conditions were maintained for approximately a month with no evidence of corrosion reinitiation. NUREG-1019, Supplement No. 1, at p. 18.

5. In the event IGSCC does reinitiate for some undefinable reason, the plant's technical specifications and license conditions will ensure a rapid plant shutdown for evaluation and repair, thus ensuring protection of the public health and safety. Sections 3.3 and 3.7 of NUREG-1019 and Supplement No. 1.

In the response opposing the motions for summary disposition, Joint Intervenors submitted the following statements:

> Contention 1(3) states, in essence, that "morphological changes" anywhere along the tube length "could reasonably be presumed to be precursors of IGSCC." IGA islands were cited as obvious examples. Licensee, after arguing that IGA "cannot be considered a precursor of IGSAC (pp. 58, 59), capitulates in the next paragraph (p. 59) with the statement, "Although IGA is not _strictly_ a precursor of IGSAC . . ." and proceeds to fall back on its ultimate argument, "because Licensee has taken adequate measures to insure that corrosive levels of contaminants will not be present, IGA _will not_ progagate into IGSAC."
>
> The Staff's argument is essentially the same. Both go on to cite the absence of laboratory failures at IGA sites as the foundation for asserting that the IGA islands will not mature to IGSAC. It is noteworthy, however, that the Staff felt compelled to place reliance on the lead tests, which have not _yet_, presumably, demonstrated progression to a failure mode.
>
> The fact of the matter is that "metallurgical conditioning of the tubing" _has_ occurred which even Babcock & Wilcox believes "may have contributed to the extent of intergranular attack." (B&W Final Report, _supra_). To hold that these changes in microstructure will not be of a continuing nature defies reason. The fact that to this day the functional scope of knowledge surrounding this phenomenon can be summarized by the speculation, "may have contributed," firmly establishes the tenuous ground upon which Licensee and the Staff stand.

Joint Intervenors have taken phrases from Licensee's Motion out of context, and characterized them as a "capitulation." Next, Joint Intervenors assert that Licensee and Staff rely entirely on the "absence of laboratory failures at IGA sites" (meaning presumably the absence of through-wall cracks in laboratory tests) in concluding that "IGA islands will not mature to IGSAC." Finally, Joint Intervenors assert that metallurgical conditioning has occurred which "may have contributed to the extent of intergranular attack." This is then characterized as "changes in microstructure" which, unless reason is defied, must be regarded as having "a continuing nature."

In fact, Licensee and Staff rely upon much more than laboratory tests to support the conclusion that in future operation of TMI-1 "IGA cannot be considered a precursor of IGSAC" (Licensee's ¶ 243). Metallographic examination of tube samples was conducted (Licensee's ¶ 233). The effect of IGA on the mechanical properties of the tubes was analyzed (Licensee's ¶¶ 239-241). Conditions for IGA propagation are discussed in detail (Licensee's ¶¶ 225-229), and the control strategies for avoiding these conditions are adequately described (Licensee's ¶¶ 242-243). The Staff also describes relevant tests (Staff's ¶¶ 3-4). We conclude that Joint Intervenors' allegation that Licensee and Staff rely entirely on the "absence of laboratory failures . . ." is without foundation.

With respect to the allegation about metallurgical conditioning and changes in microstructure, we quote from the Summary of the Babcock and

Wilcox report "TMI-1 OTSG Corrosion Test Program - Final Report" (May 9, 1983) that is cited by Joint Intervenors:

> Other factors that may have contributed to the extent of intergranular attack were . . . . Metallurgical conditioning of the tube during approximately 5 years of plant operation at 650°F (id, p. 2).

This is a summary of the following conclusion:

> The following factors, while not fully substantiated with extensive laboratory data, may also have contributed to the failures. . . . The tubing surface condition may play an important role in determining SCC susceptibility. Susceptibility to SCC appears to increase with increasing exposure at operating conditions (model boiler or steam generator operation) and exposure to a sulfur containing solution. Both of these conditions existed prior to the HFT (id., p. 19).

Another conclusion in the report is:

> This test program has essentially accomplished the test objectives. It has duplicated the mode of failures that occurred in the TMI-1 OTSG units, and it has provided an understanding of the conditions that may have caused the TMI-1 problem. However, it has raised a number of questions. Two areas in particular require additional work. Further testing should be done to determine why the higher temperature solution annealed tubing is more susceptible to intergranular attack or why long-term exposure to operating conditions (i.e., model boiler tubing) also increases susceptibility (id., p. 20).

The conclusions about long-term exposure are based on Section 4.1.3 (Actual TMI-1 Tubing Heats M2408 and M2867):

> As-received specimens of actual TMI-1 tubing removed from the OTSG were more susceptible to IGSCC than the mill annealed plus stress relieved archive heat M2320. As shown in Table 4, IGSCC occurred in nearly all of the open-circuit type tests in borated water test solutions containing as low as 1 ppm thiosulfate. For examples, see Specimens 2-138 and 2-171 in Figures 13 and 14.
>
> Of the three materials tested, the TMI-1 heats were the most susceptible to IGSCC in borated water with thiosulfate contamination. However, without the thiosulfate additions no attack was observed (see Specimen 2-141, Figure 15). (Id., pp. 11-12).

Nothing in the Babcock and Wilcox report, cited here, supports Joint Intervenors' speculation about changes in microstructure. Rather, the report conveys an uncertainty about why long-term exposure to operating conditions increases susceptibility to stress corrosion cracking.

We conclude that Joint Intervenors' three statements, supra, do not refute the statements of Licensee and Staff, because the allegation about complete reliance on the "absence of laboratory failures" is without foundation and because the Babcock and Wilcox report does not support cause for alarm about continuing changes in microstructure. The contention that the morphological changes could reasonably be presumed to be precursors of IGSCC is unsupported by material facts. Accordingly, we find that there is no genuine issue to be heard with respect to this contention and grant the motions for summary disposition. Joint Intervenors' Contention 1(3) is dismissed.

ORDER

1. The Licensee's and the Staff's motions for summary disposition of Joint Intervenors' Contentions 1(2), 1(3) and 1(5) are granted, these contentions are dismissed, and Joint Intervenors are dismissed as a party.

2. The Licensee's and the Staff's motions for summary disposition of TMIA's Contentions 1.c, 1.d, 2.a, 2.b1, 2.b2, and 2.c are granted and these contentions are dismissed. The Licensee's and the Staff's motions for summary disposition of TMIA's Contentions 1.a and 1.b are granted in

part and denied in part to the extent set forth in the Memorandum, supra.

3. Since the Board is available for the hearing in mid-July, 1984, the License, Staff, and TMIA shall confer and advise the Board by June 10th as to (a) whether a prehearing conference is necessary, and, if so, upon what date it should be convened, (b) the time in mid-July that the hearing should be held on those portions of TMIA's Contentions 1.a and 1.b which have survived the motions for summary disposition, (c) whether, in addition to the Licensee and the Staff, TMIA will submit direct testimony which will be served in written form fifteen days in advance of the hearing and as to (d) the identification of witnesses.

THE ATOMIC SAFETY AND
LICENSING BOARD

David L. Hetrick

David L. Hetrick
ADMINISTRATIVE JUDGE

James C. Lamb III

James C. Lamb, III
ADMINISTRATIVE JUDGE

Sheldon J. Wolfe

Sheldon J. Wolfe, Chairman
ADMINISTRATIVE JUDGE

Dated at Bethesda, Maryland
this 1st day of June, 1984.