UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	Dockets Nos. 50-454 OL
COMMONWEALTH EDISON COMPANY	)	50-455 OL
	)	
(Byron Nuclear Power Station,	)	
Units 1 and 2)	)	

INTERVENOR ROCKFORD LEAGUE OF WOMEN VOTERS' PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW REGARDING STEAM GENERATOR TUBE INTEGRITY

July 1, 1983

DS03

OPINION

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Rockford League of Women Voters' (League) Contention 22 and DAARE/SAFE Contention 9(c) -- Steam Generator Tube Integrity

Prior to issuance of an operating license, the NRC must find reasonable assurance exists "that the activities authorized by the operating license can be conducted without endangering the health and safety of the public" and that such activities be conducted in compliance with the NRC's regulations. 10 C.F.R. & 50.57(a)(3) Section 50.57(a)(3) is implemented with respect to steam generator tubes by satisfying 10 C.F.R. Part 50, Appendix A, General Design Criteria 14-16, 30-32, which in pertinent part state:

> Criterion 14 -- Reactor coolant pressure boundary. The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.
>
> Criterion 15 -- Reactor coolant system design. The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.
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> Criterion 16 -- Containment design. Reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require. (emphasis added)
>
> Criterion 30 -- Quality of reactor coolant pressure boundary. Components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical . . .)
>
> Criterion 31 -- Fracture prevention of reactor coolant pressure boundary. The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing and postulated accident conditions the boundary behaves

in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining material properties, the effects of irradiation on material properties, residual, steady state and transient stresses, and size of flaws.

Criterion 32 -- Inspection of reactor coolant pressure boundary. Components which are part of the reactor coolant pressure boundary shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

Criterion 14 is extremely relevant because the steam generator tubes fall under the ambit of the "reactor coolant pressure boundary." In order to establish steam generator tube integrity under this criterion and under Criteria 30 and 31, Applicant must demonstrate that design measures (such as the technical fix for flow induced vibration) and fabrication methods (such as the method of fabricating tubes) and operational procedures (such as the program for adherence to water chemistry guidelines) have been developed and tested; and that detection systems are in place (such as the loose parts monitoring system) so that under either normal operating conditions or under accident conditions there is an extremely low probability of abnormal leakage, of rapidly propagating failure, of gross rupture, and of tubes becoming so brittle that their degraded condition would eventuate in the above. Criterion 32, which requires that reactor coolant pressure boundary components be designed to permit periodic inspection and testing of critical areas, is, in essence, a means of satisfying Criteria 14, 30, and 31. Implementing guidelines to the above criteria have been issued as NRC Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes." Criteria 15 is germane because the balance of plant contained in the secondary

system comprise the associated auxiliary, control and protection systems. In order to establish steam generator tube integrity under this criterion, Applicant must demonstrate that this balance of plant (including condensers, feedwater systems, associated monitors and instrumentation, and secondary water chemistry control program) have been designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation.

Criterion 16 is relevant because, for example, it is essential for both the power operated relief valves on the reactor and the safety valves on the steam generator to function properly in order to ensure that in the event of tube ruptures, the reactor operator's emergency procedure options will not be precluded by the above to the extent that inability to fully exercise these procedures in a timely manner results in a violation of this criterion. Improper operation of these valves could result in a release of radiation to the environment in the event of an accident, violating the criterion's provision for an essentially leaktight barrier. Therefore applicant must demonstrate that emergency procedures will ensure an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment.

Additionally, Westinghouse steam generator tube integrity is designated as unresolved safety issue A-3. Pursuant to Appeal Board decisions, individual NRC safety evaluation reports must describe those unresolved safety issues relevant and potentially significant to the facility under review and some explanation why operation can proceed in advance of an overall solution. It held that the NRC Staff should make clear in the SER its perception of the nature and extent of the relationship between each significant USI and the extended operation of the reactor under scrutiny. The furnished information should determine whether (1) the problem has already been resolved for the reactor under study; a restriction on the level or nature of operations adequate

to eliminate the problem has been imposed (emphasis added); or the safety issue does not arise until the later years of operation." Gulf States Utilities Co. (River Bend Station, Units 1 and 2), ALAB-444, 6 NRC 760 (1977).

It is against the foregoing guidelines that the Board will weigh the evidence on the issues raised by Contentions 22 and 9(c).

Rockford League of Women Voters' (League) Contention 22, as litigated, provides:

> An extremely serious problem occurring at other plants such as Consumers' Palisades plant and C.E.'s Zion plant, and likely to occur at C.E.'s Byron plant, is presented by degradation of steam generator tube integrity due to corrosion induced wastage, cracking, reduction in tube diameter, and vibration induced fatigue cracks. This affects, and may destroy, the capability of the degraded tubes to maintain their integrity, both during normal operation and under accident conditions, such as a LOCA or a main steam line break. The Commission Staff has correctly regarded this problem as a safety problem of a serious nature, as evidenced both by NUREG-0410 and the Black Fox testimony cited above. As a result of this serious and unresolved problem the findings required by 10 C.F.R. §§ 50.57(a)(3)(i) and 50.57(a)(6) cannot be made. (Finding, 1)

DAARE/SAFE Contention 9(c) as litigated, provides:

> Steam generator tube integrity. In PWRs steam generator tube integrity is subject to diminution by corrosion, cracking, denting and fatigue cracks. This constitutes a hazard both during normal operation and under accident conditions. Primary loop stress corrosion cracks will, of course, lead to radioactivity leakes into the secondary loop and thereby out of the containment. A possible solution to this problem could involve redesign of the steam generator, but at FSAR, Section 10.3.5.3 the Applicant notes its intent to deal with this as a maintenance problem which may not be an adequate response given the instances noted in Contention 1, above. (Finding, 1)

To address the contentions, Applicant presented the testimony of eleven witnesses. Mr. John C. Blomgren, of Commonwealth Edison Company, addressed various measures that will be employed at the Byron Station to minimize steam generator tube degradation. Dr. Mahendra R. Patel, of Westinghouse Electric Corp., addressed the "leak-before-break" principle and steam generator tube plugging criteria. Other witnesses from Westinghouse

included Mr. Daniel Malinowski, who addressed the inspection measures used to detect steam generator tube degradation; Dr. Michael J. Wootten, who addressed the water chemistry measures used to minimize tube degradation on the secondary side of the steam generators at Byron; Dr. Lawrence Conway, who addressed the design changes in D4 and D5 steam generators at Byron; and Mr. Thomas Timmons, who addressed the flow-induced vibration phenomenon. Mr. Lawrence D. Butterfield, of Commonwealth Edison, addressed Applicant's modifications with respect to the flow-induced vibration phenomen. Applicant also presented the testimony of Mr. Kenneth J. Green, Mechanical Project Engineer for Sargent and Lundy Engineers, who addressed the issue of whether the proposed modifications to the Byron steam generators described by Messrs. Timmons and Butterfield might increase the liklihood of a waterhammer event in the Feedwater Bypass Systems of the Byron steam generators, and Mr. Rodolfo Paillaman, a Senior Quality Assurance Non-Destructive Examination Specialist with Ebasco Services, Inc., who addressed the pre-service inspection of the steam generator tubes at Byron.

Mr. Wilson D. Fletcher, Manager of Steam Generator Materials and Chemistry of Westinghouse, provided an overview of the steam generator tube integrity issue and Mr. Michael Hitchler, Manager of Probabilistic Risk Assessment with the Nuclear Safety Department of Westinghouse, quantitatively assessed the probability of steam generator tube ruptures under various conditions.

The NRC Staff presented the testimony of Dr. Jai Raj N. Rajan, a mechanical engineer, who addressed the flow-induced vibration phenomenon and the probability of tube rupture under various conditions; Mr. Ledyard B. Marsh, who addressed various steam generator tube degradation issues;

Mr. Louis Frank, a senior materials engineer, who addressed secondary side water chemistry measures and inservice inspections; and Mr. Conrad McCracken, who addressed steam generator design and secondary side water chemistry measures to reduce corrosion.

The League presented the testimony of Mr. Dale G. Bridenbaugh, a nuclear engineer and President of MHB Technical Associates in California, who addressed various aspects of steam generator tube integrity issues concerning the Byron Station. (Finding, 2)

The steam generator tubing, which is part of the reactor coolant pressure boundary, is an important barrier against the release of radioactivity to the environment from the primary system. Accordingly, design criteria for tube wall sizing have been established to assure structural integrity of the tubing under normal operating and the postulated design-basis accident condition loadings. (Finding, 3)

The normal wall thickness of a steam generator tube is .042 mils which is thought to be sufficient to fit in with the above. (Finding 4.)

However, the operating experience of PWRs has shown that over a period of time under the influence of the operating loads and environment in the steam generator, steam generator tubes ~~may~~ can become degraded and leak. (Finding 5.)

Implicit in the language of General Design Criteria 14-16, and 31, which speak to abnormal leakage, rapidly propagating failure, gross rupture, leak-tight barrier, uncontrolled release, and exceeded margins, is the recognition that some degradation and leakage will inevitably occur over the lifetime of a plant.

Tube degradation problems at Westinghouse steam generators are an NRC unresolved generic safety issue and have included the following: wastage and

thinning, corrosion, denting, pitting, intergranular attack, stress corrosion, cracking, wear caused by flow-induced vibration, and wear and/or impact damage as a result of foreign objects or loose parts. (Finding, 6)

Early immoderate use of phosphate water chemistry resulted in tube wall thinning, a localized reduction in the tube thickness resulting from corrosion by phosphates in high concentrations. It is caused by low sodium to phosphate ratio solutions, or a concentrated solution of sodium phosphate which was the corrosive agent which caused the thinning of the tubing. (Finding,)

Tube wall thinning has been observed within sludge piles at the top of the tubesheet and at tube support plant elevations, where lower flow velocities allowed concentration of phosphates to saturation levels. (Findings 5, 7, 8)

The change to all volatile treatment (AVT) water chemistry controls stemmed the thinning of the steam generator tubing caused by acidic phosphate species. (Finding, 9)

Thinning has been reduced to the point where it is no longer a major contributor in plants that have switched to AVT. (Finding, 10)

While the change to AVT mitigated thinning caused by acidic phosphate species, in the immediate years following the conversion to AVT, another form of corrosion called "denting" was observed with AVT use. (Finding, 11)

Denting is a process whereby corrosive impurities are concentrated in the space between the tube and tube support. The resultant corrosion converts the base support metal to metal oxide. (Finding, 12)

Denting is due to corrosion of the carbon steel support plates. It does not directly result in steam generator tube corrosion. (Finding 13)

Inconel 600 was chosen for the steam generator as tubing now being the most suitable material available for the temperatures, chemical environment, and design basis accident conditions present within the steam generator. To reduce chemical concentrations areas such as at the tube sheet and between the tube and tube support plate, recirculation rates were increased, the ports in the blowdown pipe were modified, and the tubes within the tube sheet hole were expanded to eliminate the crevices at the tube sheet. (Finding, 24)

Denting will still occur at Byron Unit 1. It will take from 3-10 years for initiation, depending on how well the water chemistry guidelines and condenser inservice inspection program are adhered to. (Finding, 17)

Stopping condenser inleakage is an absolute measure to stopping corrosion, if the makeup water treatment is also sufficient. The NRC is considering making it a requirement that condensers be inspected routinely as steam generators are. (Finding, 20)

Tube wall cracking generally occurs in a local region and the crack may extend through the entire wall thickness. Depending upon the orientation of tube wall stresses, cracks may initiate from the outside diameter or the inside diameter of the tube. All tube stress-corrosion cracks detected in Westinghouse-designed steam generators have been intergranular in nature. Intergranular attack is a form of tube degradation usually characterized by general grain boundary dissolution. It occurs in conjunction with stress-corrosion cracking on the outside diameter of the tube; it usually occurs within crevices between the tube and the tubesheet. (Finding 21)

Tube wear is a form of tube degradation that results from a mechanical abrasion of the tube surface. Such wear progressively reduces the thickness of the tube area affected. Wear results from the impact of adjacent structures or loose objects on the tubing; it has been observed at antivibration bar intersections, the baffle plates in preheat sections and locations in contact with foreign objects. (Finding 22)

Steam generator design.

Both Byron Unit 1 and Byron Unit 2 have preheat steam generators which are functionally identical. Byron Unit 1 is a model D-4 and Byron Unit 2 a model D-5. The difference between these designs occured as part of the normal eVolution over time of steam generator designs. (Findings 23, 25, 26)

In addition, the design of the Model D-5 in Unit 2 is better than the D-4 in Unit 1 because it (1) uses stainless steel, a more corrosion-resistant material, as the material for the tube support plates and baffles, (2) changes the shape of the holes in the tube support plates from circular to a quatrefoil shape to improve flow, (3) expands the tubes within the tubesheet by means of a hydraulic device in lieu of mechanical rollers to reduce stresses, (4) thermally treats the Iconel 600 tubes to enhance resistance to corrosion, and (5) changes the holes in the flow distribution baffles from slotted to a circular shape to improve flow. (Findings 25, 26

Flow-induced vibration.

Since 1981, a design problem with flow induced vibration and subsequent wear of tubes in the preheater section of Model D steam generators has been identified at newly operational plants with Model D steam generators. (Findings, 27, 28)

These include McGuire Nuclear Station, Unit 1 (Model D2) and the following three foreign facilities: Ringhals, Unit 3 (Model D3), Almarez Unit 1 (Model D3), and Krsko (Model D4). (Finding 28)

Certain tubes in the preheater region of the steam generator vibrate against the baffle plates as a result of the turbulence created by the feedwater flow entering from the main feedwater nozzle. (Finding 29)

The tube excitation mechanism appears to be a combination of a threshold type of fluid elastic instability and turbulent buffeting. (Finding 30)

Oscillating drag forces are produced in large measure by the presence of the impingement plate and the flow held that that plate creates unsteadiness of the flow field in inlet plenum. (Finding 31)

Model D4 and D5 steam generators employ counter flow type preheater design. The split flow design is employed for Model D2 and D3 steam generators. (Finding 32)

In October 1981, flow-induced vibration was identified as the cause of a tube leak in Sweden at Ringhals Unit 3, a plant with Model D-3 steam generators. The degradation was in the form of a through-wall hole in a single tube at a baffle plate. Eddy current testing performed also indicated tube wall wear in outer 3 rows of preheator tubes. (Finding 33)

Ringhals had operated at 100% power, 100% main feed for only 2,000 hours when the tube leak occured. (Finding 34)

Possible tube wear was also detected at Almarez, another newly operational D-3 plant which had operated only 1,500 hours at 100% power in October 1981. (Finding 35)

Eddy current testing was also performed at McGuire 1, a domestic plant with Model D-2 steam generators and at Krsko, a non-domestic plant with Model D-4 steam generators. There no indications were found, but the latter two plants had not operated very long above 50% power, McGuire operations for only 1,000 hours and Krsko for 300 hours at 40% power. (Finding, 36)

Because the tube wear potential due to vibration was serious, Westinghouse started a program to investigate, understand and define vibration and tube wear in Model D steam generators using and reviewing tube wear data from operating plants and from model tests to conceive, develop, test, evaluate any modifications necessary to allow operation of Model D steam generators at full power. (Finding, 37)

McGuire, Almarez, Ringhal, and Krsko were instrumented with accelerometers between December 1981 and March 1982 to try to correlate tube vibration data to tube wear data to predict potential tube wear over same operating period. (Finding, 38)

. The Accelerometers at Krsko were placed in the 4 tubes thought to be the ones that would be most susceptible to tube vibration, and would exhibit the highest levels of vibration. (Finding 39)

May of 1982 one tube was removed at Krsko. It had 6% tube wear in one location and 1% in another. This was also one of the tubes in which an accelerometer was placed. (Finding 40)

Krsko shut down again in late October 1982. Two previously instrumented tubes were removed and one tube expanded. The two removed tubes had wear indications of 2-4%. Krsko began again in November. Accelerometers were installed in the expanded tube. Vibration data was gathered at this point for various feedwater flow configurations. (Finding 41)

At the time, October 1982, these feedwater flow configurations were used to take accelerometer data and measure changes in vibration levels with changes in main feedwater into main nozzle, Krsko had only between 24 and 48 hours at 100% main nozzle flow. With only one original instrumented tube and a newly expanded tube, Krsko did not have a very sizable data base for conclusions drawn from it. (Finding, 42)

The tubes removed in October from Krsko were used to determine whether flow levels of vibration resulted in any demonstratable amount of wear and the vibration boundaries of the tube bundle. They demonstrated that tubes with a high level of vibration generally suffered only a little bit more wear over extended periods of time than tubes with a low level of vibration. (Finding 43)

The vibration data from Krsko collected at various power levels and various combinations of main feed and bypass feedflows showed that the tube vibrations of the 70% main feed/30% bypass feed combination were slightly greater than those of the 70/0 combination and that the vibrations observed at 70/30 were acceptable. (Finding 44)

As Applicant witness indicated, correlation of tube wear with vibration is a very complex function. Ninety percent or 100% main feedflow through the main nozzle is found to contribute much more significantly to wear function than operation at lower power levels. "It is a strong function of the amount of flow." (Finding, 45)

Collected data indicating that high main feed flow rates with unexpanded tubes could produce significant vibration of some tubes, resulting in greater wear than at lower feed flow rates. (Finding 46)

The tube vibration data obtained from use of the expanded tube at Krsko indicated that the tube vibrations in both steam generators were similiar and had not changed with time. The expanded tube had been previously instrumented for vibration and reinstrumented. Previous tube vibration data was compared with the data obtained after the tube had been expanded and it was concluded that the tube vibrations were reduced by at least a factor of 5 from the nonexpanded tube. (Finding 47)

As part of the generic Model D4/D5 program, a 16° full scale and a single tube vibration model was used to replicate in the laboratory the tube vibration response observed in operating steam generators. (Findings, 48 .)

In the 16° model, a number of tubes were expanded and testing was conducted to determine the effect of tube expansion on tube vibration. At a flow rate equilvalent to 90% of the Byron main feel flow rate, the expanded tubes exhibited vibration levels that were less than those observed at flow rates equilvalent to 70% of the Byron main feed flow rate without tube expansion. (Findings, 49 .)

But the model tests were all run at cold conditions requiring that a correction factor be used to obtain hot condition data, which introduced a further uncertainty of 10-20% in the correlation. (Findings, 50 .)

The 2/3 scale model tests did not allow measurement of a critical threshold water velocity at which vibration begins. (Findings, 51 .)

There is confusion about the nature of the vibrations phenomena.

Witnesses Fletcher and Rajan state that the tubes are being moved by a complex mixture of both turbulence and fluid-elastic vibration, but Timmons disagrees fluid-elastic instability is present. (Findings, 52, 53.)

Timmons says there is no data from full scale model tests that indicate fluid-elastic vibration for counter flow program. (Findings, 53 .)

The object of the preheat region is to extract more heat from the primary fluid. For that reason a certain amount of turbulence is desirable. However, a side effect of this increased turbulence is vibration of some of the tubes in that region against the support plates. Fluid-elastic instability is probably present and this has resulted in less than acceptable tube wear on the tubes. (Findings, 54 .)

The problem of flow induced vibration has been at the support plate location. The support plate location is about a one inch thick piece of steel where the tube goes through a hole that has a nominal 20 mil clearance. When the tube vibrates, the tube within that support location becomes worn. If there is a one inch support location and thickness, a one inch spot on the tube is worn. (Findings, 55 .)

It's not possible to measure drag forces on tubes in operating D2-D3 plants. (Finding 56)

Premised upon its investigation, Westinghouse has recommended that Applicant make the following modifications to the Byron plant to reduce the potential for significant tube vibrations in the Byron steam generators: (1) the expansion at baffle-plate locations in the preheater region of approximately 100 tubes per steam generator and (2) the bypassing of approximately 10% of the flow from the main feedwater nozzle to the auxiliary feedwater nozzle. The expansion of tubes at baffle-plate locations will limit tube movement at the baffle-plate intersections to a resultant few thousandths of an inch clearance. The bypassing of 10% of the main feed flow to the auxiliary nozzle of the steam generator will reduce the main feed flow at the inlet to the preheater to approximately 90%. (Finding 57)

The tube expansion process is scheduled to begin in mid-July prior to start up of the Byron Station. Changes to the control circuitry of the feedwater preheater bypass valve and the installation of a feedwater bypass line flowmeter will occur at the same time as the tube expansion program. (Finding 58)

The tube expansion involves the insertion of tools into the tube from the primary side of the steam generator tube sheet. The tubes are then used to locate the baffle plate intersection and to expand the tube at the appropriate location. (Finding 59)

The process is called hydraulic expansion. Westinghouse has used hydraulic methodology for expanding steam generator tubes in the tube sheet since 1977. There has always been concern over the residual stress leval of expanded tubes. (Finding 60)

Westinghouse's determination of the levels of residual stresses in expanded tubes and conclusion that the levels of residual stresses in expanded tubes combined with the relatively low temperature in the preheater region will not significantly increase the potential for stress-corrosion cracking in the expanded location is based upon tests on earlier expansion . of tubes in the tube sheet. (Finding 61)

Expansion of tubes at baffle plate locations will limit the tube movement at the baffle plate intersections to a few thousandths of an inch. (Finding 62)

Westinghouse has also conducted "accelerated" corrosion testing to assess the effects of the reduced tube-to-tube hole clearance on the potential for denting of the expanded tubes, but applicant did not provide evidence on this matter at hearing, and it si difficult to simulate aged degradation. According to Westinghouse, the results of this testing indicate that the potential for denting is not increased for tubes expanded at the baffle intersections. (Findings, 63)

The 100 tubes identified as candidates for expansion at Byron are regarded as a bounding number. It is not actually known which tubes will be selected. (Finding 64) These tubes have been determined to be the most susceptible to tube vibration.

The precise location and number of tubes to be expanded is not yet known. (Finding 65)

Westinghouse has established a vibration leval at or below which it does not expect a 90-10 flow split of approximately 100 expanded tubes and non-expanded tubes in each steam generator will reach the 40% tube wall degradation level requiring plugging as a result of the flow-induced vibration over the 40-year life of the plant. (Finding 66, 67)

Neither does it expect non-expanded tubes at Byron to experience 40% wear through the tube wall over the 40-year life of the plant. (Finding 68)

Timmons contradicts this conclusion and admits that a small number of expanded tubes may have to be plugged over the lifetime of plant, and that some of his colleagues at Westinghouse may have specific tubes picked out which may have to be plugged due to vibration wear. (Findings 69, 70)

Later Timmons changed his testimony to remark that no tubes will have to be plugged at Byron over its life. He says that he has received other information that indicates expanded tubes and bypassing feedwater flow is such that vibration would remain below a threshold level that would lead to tube plugging. This of course is the threshold level Westinghouse earlier testified they were not able to establish existed. (Finding 71)

Timmons didn't know how many more hours it would take for the tube with 6% degradation removed from Krsko in May to reach 40% degradation given the same power level ranges for the period January - May of 1982. (Finding 72)

Westinghouse intends to install accelerometers at the first plant at which the proposdd modification is to be implemented in order to confirm that the vibrations seen in that plant are representative of those seen in the test models and at Krsko. (Finding 73)

In fact, more accelerometers have been put in Krsko to further determine the boundaries of tube vibration, yet in Timmon's opinion it will not be necessary to install accelerometers at Byron because the data gathered from Krsko and test models has already done the necessary correlating of vibration to tube wear. (Finding 74)

There is a possibility Byron may be that first instrumented plant after all. According to Timmons, Comanche Peak Unit 1 will be the first operational plant instrumented not Byron, but he is wrong on the Comanche Peak fuel load date. Staff believes Byron and Comanche Peak will load December of 1983. (Findings 76, 77)

Twelve tubes are now instrumented at Krsko. (Finding 74)

Timmons states that instead of removing expanded tube at Krsko in June 1983, it might be better to leave it as is and see what effect expansion of 100 other tubes around it has on the vibration of that tube. This still is not known. (Finding, 78)

Timmons states that Byron would conduct eddy current testing to verify that the tubes were not wearing and that would constitute part of the post modification testing program. The post modification testing program is very important to determine long-range integrity of expanded tubes. (Finding, 80)

Special inspections were done over the past 6-9 months at McGuire (D2-D3) on the tubes in the pre-heater area. (Finding, 81)

Staff indicated an enhanced inspection program like that at McGuire will be required for tubes expanded at the support plates (baffle plates), but neither applicant nor staff witness knew the specifics about such a proposed program for Byron, including inspection intervals and techniques, and evaluation. (Findings, 82)

across the wall for a non-instrumented tube. Initial fluid testing by Westinghouse indicated vibrational characteristics between the two types of tubes differ less than one percent, but the long term certainty of this isn't established. (Finding 83)

Westinghouse considered at one point the insertion of either solid rods or cables or something inside potential high vibration tubes, but apparently thought that though it would stabilize the tubes so that they could not sever and become loose parts within the steam generator, it would not necessarily cut vibration and it would take a significant amount of resources to design and manufacture a sufficient number of these devices to be able to apply them in the plants in any short period of time. (Findings, 215, 216)

Yet, Krsko's split loal of 70/30 on 100% power is a long-term concern in terms of tube wear. And, Krsko will undergo further modification, expand 100 tubes, and operate on an 80/20 split. Thus high main flow still appears to be a Westinghouse concern. (Findings, 218)

A 70/30 feedwater split at Krsko would translate into approximately a 75/25 split at Byron but such a reduction in main nozzle feed flow was not thought neccessary at Byron if a 90/10 split was used in conjunction with 100 expanded tubes. (217, Findings)

If Byron is the first plant to experiment with the Westinghouse modifications, Westinghouse intends to instrument it. (Findings, 219)

The latest information identified in page 5 of Rajan's prefiled testimony consisted of the general identification of the tubes that will be expanded, their matter of expansion and supporting data from model tests which justified the selection of the tubes. This information was only presented to the NRC and Rajan at a meeting just one week or ten days prior. (Findings, 220)

With the exception of sponsoring research efforts at various laboratories; in this case at Argonne National Lab, no (NRC sponsor or) agency other than Westinghouse has reviewed or conducted testing on flow-induced tube vibration. Furthermore, Argonne, while familiar with data collection techniques and plant sites has not conducted tests such as Westinghouse's, except for single tube models which are more routine. Argonne has merely reviewed the data accumulated by Westinghouse from operating plants and tests with respect to this recent tube vibration issue. (Finding 89)

Staff has not recieved a final report on the proposed modifications from Argonne at this time, and will not recieve the evaluation until a week or two of the Westinghouse report. (Finding 91)

Argonne's review of the tube vibration issue is based upon viewgraphs, and a formal report recieved from Westinghouse on the D2, D3 modification, including the analytical methods, operating plant data and their evaluation package. (Finding 91)

NRC Staff review

Contrary to Applicant's opinion, the efficacy of the Westinghouse proposed midifications has not been the subject of an extensive review and verification process by NRC Staff. (Finding 221)

Frank states that Applicant has to submit to Staff their recommendations for operation with the modifications. Nothing has formally been presented to Staff by Applicant or Westinghouse. (Finding 222)

Dr. Rajan is not a competent witness for Staff in establishing the empirical basis for Staff's interim conclusion on page 5 of his revised prefiled testimony that "Based on Staff's preliminary review of the proposed modifications, the objective of mimimizing tube degradation associated with flow-induced vibrations will be accomplished by these modifications." His familiarity with the data Westinghouse recieved from operating plants, scale model test-

ing, and Krsko tube expansion, is not sufficient to objectively reach that conclusion. It is not an empirical conclusion reached by review of the actual data. Instead he formed it on basis of View-graphs presented to Staff by Westinghouse as data summations. (Finding 223)

Except for his personal notes, Rajan has no formal submission or report from Westinghouse on results of scale model tests. (Finding 224)

The Staff review of the proposed modifications will be completed prior to plant operation, and a safety evaluation report issued following its implementation at Byron. (Finding 225)

() Loose Parts Monitoring System

Foreign objects can cause a tube rupture. Two such recent incidents have occurred at Prairie Island Unit 1 in 1979 and at Ginna in 1982. (Finding, 92)

The Prairie Island rupture was due to a coil spring which remained in the steam generator following an earlier outage for steam generator maintenance. (Finding 93)

The Ginna rupture was also due to the presence of a foreign object which impacted against and severed a previously plugged tube. The severed tube subsequently wore against an unplugged tube providing a long wear scar which ultimately led to tube leakage. (Finding 94)

The potential for damaging tubes as a result of foreign objects and loose parts being present in steam generators can be minimized by appropriate surveillance. Examples of available surveillance methods include visual inspections with the aid of fiber optics and/or radio camera devices, and loose parts (acoustic) monitoring of the steam generator during operation. (Finding 95)

The problem is this advanced equipment may only be at the disposal of Westinghouse and not utilities, such as Edison. Edison indicated multi-frequency eddy current testing capability. Primary reliance will be placed on that and the LPMS for initial surveillance.

Visual inspections on the secondary side of the steam generator of plugged tubes are not normally performed, but Applicant intends to conduct periodic visual inspections of the secondary side of the steam generators during refueling and maintenance outages. (Findings, 96, 97)

Still, plugged tubes cannot be tested for loose parts potential because no eddy current test exists for plugged tubes. (Finding, 98)

Page IV.7.1 of the S.A.I. Report, Section 7.1.1, indicates "PWR licensees shall be required to develop criteria and procedures for stabilization of degraded tubes that may be subjected to progressive degradation mechanisms having the potential to cause severance of the tube and consequently to damage adjacent tubes." This is not a requirement, but it is good practice. (Finding 99)

Byron is being required to implement Regulatory Guide 1.133 which provides in part for a loose parts monitoring system. (Finding 100)

This system includes two sensors on the secondary side of each steam generator. These sensors listen for noise generated by loose parts. (Finding 101)

Materials and tools used in the steam generators during maintenance and inspection will be controlled through written tool and material inventory control procedures. The control procedures will require an inventory and accounting of all tools and materials entering the secondary side of the steam generators prior to return to operation. In addition, hold points will be required in maintenance procedures for cleanliness operations. (Finding 102)

These procedures are still in draft form though and may or may not be in place before fuel load, and no one of staff panel was familiar with LPMS at Byron. (Findings, 103)

In fact, this was an area of much dispute. McCracken claims Byron SER describes only a primary system LPMS, but on next page Frank quotes a sentence that says, "There will be two accelerometers on the lower plinum of each steam generator." That seems to indicate Byron has a secondary system LPMS. (Findings, 104, 105)

Mr. Blomgren has looked at the loose parts monitoring system at Byron and its specifications and feels the LPMS of Byron should be able to meet the requirement of Reg. Guide 1.133 that a 1.25 lb. metallic part impacting with a kinetic energy of 0.5 ft./lb. be detected if it is within 3 feet of the detector. (Finding 106)

Mr. Blomgren, however, is not "completely familiar with all the techniques that are involved with detecting loose parts and evaluating the size and position of those parts." (Finding 107)

The sensitivity of the loose parts monitoring system depends on a number of factors and involves a pretty complicated estimate to determine the sensitivity of a given sensor, and the ultimate sensitivity of the Byron LPMS will not be determined until some time during the early stages of the start-up of the plant. (Findings, 108)

To say specifically that the Byron system will be able to do this or that is really going to be based only on the results of the start-up tests. (Finding 109, 110)

Still, Edison has concluded that due to the LPMS and water chemistry guidelines a tube stabilization system will not be needed at Byron. (Finding 111)

However, it is Bridenbaugh's understanding that the LPMS is not an active system, is there for periodic monitoring, and is not required in technical specifications, i.e. is not a limiting condition for operation. He believes it should be. (Finding 112)

Additional generic surveillance requirements are undergoing Staff development and review. (Finding 113)

The LPMS is expected to reduce the potential for the types of problems which have been experienced to date. However, some degree of degradation is likely to occur at Byron during its lifetime. Given the potential for degradation, surveillance requirements are essential to ensure adequate tube integrity is maintained against rupture and excessive leakage during the full range of normal operating and postulated accident conditions. (Finding 114

Commonwealth Edison will monitor the Byron reactor systems for primary to secondary leakage. To stem degraded tubes from occurring to the point where rupture is possible, licensees are required to shut down and repair steam generator tubes should the primary to secondary leakage exceed a maximum allowed by technical specification. (Finding 115)

The maximum permissible leak rate is established consistent with the "leak-before-break" principle set forth in the Technical Specifications. Inconel 600 is used in steam generator tubing, a material in which degradation in the form of cracking penetrates through the wall causing a small primary to secondary leak long before the crack reaches a linear length called the "critical length," where tube rupture can occur. This is supposed to safeguard wall integrity, but, none the less, tube ruptures have occurred. (Finding 116)

The maximum permissible leak rate during normal operation at Byron has been established through leak rate and burst pressure tests at the Standard Technical Specification limit of 0.35 gpm per steam generator. Finding (117)

This corresponds to a maximum allowable crack length of 0.43 inch. Yet the Ginna rupture was a single tube rupture at 700 gpm.

The critical crack length corresponding to the maximum accident condition pressure during a postulated Main Feedwater Line Break (MFLB) or Main Steam Line Break (MSLB) was conservatively determined to be 0.51 inch using the results of the burst pressure tests. (Finding 118)

Thus, shutdown for remedial action should take place before the critical crack or calculated burst point of 0.51 inch is reached. (Finding 119)

Partially degraded tubes are acceptable for continued service as long as it is assured, through inservice inspections (utilizing eddy current techniques) and leakage monitoring, that degraded tubes meet the applicable tube wall and associated strength requirements to safely withstand all operating and design basis accident condition loads. (Finding 120)

Section VI of the ASME Boiler and Pressure Vessel Code (Code) provides guidelines for establishing the "limiting safe conditions" of tube degradation beyond which defective tubes must be repaired or removed from service.

limiting safe condition takes into account (1) the minimum tube wall thickness needed in order to sustain the imposed normal operating and postulated design basis accident condition tube loads; (2) maximum (Technical Specification) permissible leak rate during normal operation to preclude a tube rupture during a postulated main steam line break accident and (3) allowance for continued degradation between inspections and eddy current measurement uncertainties. (Finding 121)

Plugging margins established in accordance with the requirements ensure that, at the end of an operating period, a degraded tube with loss of wall or a leak (1) will not undergo progressive yield (permanent deformation during operation), (2) will not burst or rupture during either normal operating or the governing design basis accidents, and (3) will meet, under the postulated accident condition loadings, the applicable stress limits specified in Appendix F of Section III of the Code. (Finding 122)

Applicant follows Section XI of the Code in lieu of the plant-specific program described in NRC Regulatory Guide 1.121. The amount of tube wall degradation above which the tube shall not continue in service, the tube plugging criterion, established by Section XI of the Code, paragraph IWB-3521.1, is a depth of outside wall penetration not to exceed 40% of the wall thickness for tubing from SB 163 material when the mean tube radius to wall thickness ratio is less than 8.70. ASME calculations conclude that 50% of tube wall thickness can still meet all applicable stress and strength requirements. (Findings 123,124)

The 40% figure allows for a <u>10% uncertainty factor in both eddy current measurement and corrosion allowance for continued plant operation until the next inspection.</u> (emphasis added) (Findings 125)

Based on Regulatory Guide 1.121, it could be concluded that the thickness necessary for a tube to bear accidents or normal operation generally approaches 40%, i.e., 60% degradation, thereby building in an extra 10% conservatism. (emphasis added) Finding 126

Thus from Regulatory Guides one could conclude that significant tube degradation will be detected well within the sensitivity limits of eddy current testing, 20% to 40% tube wall loss depending upon the type of tube degradation. (Finding 127)

Pre-service and In-service Inspections

Commonwealth Edison performed a baseline examination of the tubes in the steam generators at Byron. The purpose of performing the pre-service inspections is to establish a baseline against which subsequent in-service inspections can be compared. A pre-service inspection was conducted of 100% of the tubes using multi-frequency eddy current examination. The eddy current probe is designed to measure any severe departures from a nominal condition. (Findings 128-130)

The data was reported in accordance with Article IV-6000 of ASME Section XI, which requires the reporting of tube wall penetrations in excess of 20% of the tube wall thickness and tube wall dents. (Finding 131)

Based upon the inspection, a baseline was established for Unit 1. The inspection revealed that two tubes were partially blocked. The cause of blockage could not be determined. (Finding 132)

Based on a Westinghouse recommendation, the two tubes were plugged. (Finding 133)

Some processing-induced denting was discovered. The dents or "dings" were not considered sufficiently significant to warrant tube plugging as no tube locations were found with 20% or greater wall loss. Most of the denting was located four or 5 inches away from the tubesheet. That is, in the preheater beltline. (Finding 134)

Dr. Paul of Ebasco Services, Inc., was originally scheduled to testify about the pre-service inspection program but Applicant presented Mr. Rodolfo Paillaman instead. Paillaman's testimony was a revision of Dr. Paul's

prefiled testimony, including a revision of answer 8, page 8. (Findings 135, 136)

Paillaman scratched out "especially in Row 1 of Steam generator No. 1," from "A number of tubes, especially in Row 1 of Steam generator No. 1, were found to have processing-induced dents," in Paul's original testimony. Paillaman did not agree with the sentence as written by Paul which would highlight defects found in Row 1 tubes which is a suspected area for service-induced dents and cracking at the apex of U-shaped tubes as a secondary effect of denting. (Findings 137, 138)

There were from 2 to 3 dents on selected tubes for a total of 600 dents in Steam generator No. 1, 500 for Steam generator No. 2, 450 for Steam generator No. 3, and 550 for Steam generator No. 4. Steam generator No. 4 was found to have a large number (124) of tubes with indications of permeability; a localized area of magnetic material or impurities in the Inconel which require a different technique for an examination to verify integrity of the tubes. (Findings 139, 140)

The condition of the Byron steam generators will be periodically monitored through an inspection program. Inspections will be performed according to the provisions of the Byron Technical Specifications and according to NRC Regulatory Guide 1.83. (Findings 141)

The results of these periodic inspections will be compared to the 100% pre-service baseline examination. This comparison will provide a periodic evaluation of the steam generator tubing condition to allow time for the initiation of appropriate measures for steam generator maintenance prior to any occurrence of primary to secondary leakage. Findings 142

NRC Regulatory Guide 1.83 requires that in-service inspections be performed every 12 to 24 months.

In cases where the degradation processes have been highly active, the Staff has required that the inspections be performed at more frequent intervals, consistent with the rate at which degradation is occurring. (Findings 143)

Technical Specifications require sampling (at minimum) 3% of all the tubes in the plant in the first in-service inspection. Future inspections may be expanded to cover 100% of the tubes in circumstances where either (i) greater than 10% of the tubes inspected have eddy current indications greater than 20%, or (ii) greater than 10% of the tubes inspected exceed the plugging criterion. (Findings 144)

The total number of tubes to be inspected during an in-service inspection will range between 3% and 100% of the total number of steam generator tubes. The flexibility of inspection procedures suggests the basis for a post-Westinhouse modification monitoring program, on the flow-induced vibration issue. (Findings 145)

At Byron subsequent inspections will relate to all unplugged tubes previously identified to have eddy current indications greater than 20% as well as the 3% total sample provided by the Technical Specifications. (Id. at 7-8) (Findings 146)

Eddy current testing is the primary inspection technique and it is usually performed using an instrument that impresses four different test frequencies on the coils simultaneously. The frequencies are selected on the basis of providing definitive information on tube degradation, support plates and external deposits. Because the responses for external discontinuities vary according to the test frequency, it is possible by linear combinations of the responses at different frequencies to reduce unwanted signals from a composite response. Bridenbaugh questioned the amount of experience with eddy current testing, he acknowledged that multi-frequency testing is a significant improvement over earlier

methods and <u>may be adequate</u>, depending on type of tube degradation experienced. (emphasis added) (Findings 147)

The sensitivity of eddy current testing to tube wall degradation varies depending upon the size, shape and nature of the degradation. Eddy current testing will reliably detect the various types of tube degradation at the following sensitivity levels: tube wall thinning at 20% depth of the tube wall pitting at 20% tube wall depth; tube wall cracking at 40% tube wall depth; intergranular attack at 40% tube wall depth; tube wear at 20% of tube wall depth. Denting, a form of tube deformation, can be detected by eddy current testing. (Findings 148)

Eddy current development now in progress in the industry is expected to further improve detection limits and characterization of possible tube degradation. (Finding 148)

The eddy current method should enable significant tube wall penetration at or below the plugging limit of 40% to be detected. (Finding 149)

If a significant rate of tube degradation is determined as a result of an in-service inspection, measures are available to reduce the probability that tube leakage will occur before the next scheduled inspection. These measures include (water chemistry) alterations such as temperature changes, water lancing, flushing and chemical cleaning to try to loosen and remove degradation-causing impurities or deposits; foreshortening and <u>reducing the interval between inspections</u> or plugging more tubes. (Finding 150)

Water Chemistry

The entire history of operating plant experience has shown the absolute need for rigorous monitoring and control of the secondary side water chemistry environment, including the condensate feedwater systems, and balance of plant located on the secondary side. (Findings, 151 .)

The extensive laboratory work that has been performed in evaluating the mechanisms of stress corrosion cracking, thinning and denting of the steam generator tubes, has proven that all impurities admitted to the steam cycle will ultimately reside and accumulate in the steam generator. Therefore the admission of these impurities must be highly limited. (Findings, 152).

Impurities such as air, which contains oxygen, condenser cooling water impurities such as nickel and copper, fresh water sources that contain minerals contributing excess and alkalinity, makeup water impurities such as chlorine and the like, must be excluded to the extent possible from the secondary side. It has been demonstrated that copper and nickel bearing alloys in the feed train can participate in corrosion reaction when transported to the steam generators. (Findings, 153 .)

Accordingly, the Applicant is implementing an AVT water chemistry program on the secondary side of the reactor systems at the Byron Station. (Findings 154)

Good AVT chemistry control is based on a philosophy of minimum contaminant ingress through the practice of good initial design and material selection of condensers, feedwater heaters, makeup water systems and other components. (Finding 155)

Good AVT control can only be maintained by rigorous inspection and maintenance practices and strict operator adherence to all secondary chemistry operational procedures during plant operation. Adherence to AVT guidelines is necessary to enhance the long term integrity of the steam cycle, by reducing the corrosion of condenser and feedwater materials, the steam generator and the turbine to the extent possible. This in turn will reduce the formation of corrosion products which are delivered to the steam system. (Findings, 156 .)

AVT involves the addition of volatile chemicals as control agents. With proper monitoring of the input and output of these chemicals, they should not concentrate in the steam generator but are removed via the steam to the remainder of the secondary system. At least two chemicals must be added, a volatile amine (usually ammonium hydroxide) for pH control of the feedwater and an oxygen scavanger (hydrazine). Hydrazine scavenges oxygen producing byproducts, such as nitrogen which is innocuous provided pH is controlled within a specified range. As the hydrazine moves through the feedwater system and is subjected to higher temperatures, any unreacted hydrazine will decompose to form volatile compounds such as ammonia, nitrogen and hydrogen. The addition of ammonium hydroxide for pH control must be

continuously adjusted to compensate for the volatile compounds produced from the excess hydrazine thermal decomposition. (Findings, 157 .)

Applicant's AVT water chemistry program is based on Westinghouse and EPRI guidelines. (Findings, 158 .)

In order to reinforce the need for vigorous chemistry control, EPRI has issued AVT guidelines as a model to be reviewed by the NRC and the industry. (Findings, 159 .)

The Westinghouse guidelines, introduced in 1977 and modified subsequently from time to time, recommend that (1) the guideline chemistry conditions should be achieved prior to unit loading and maintained during power changes; (2) any source of contamination should be identified, the source corrected and no operation allowed with locatable contaminant ingress; (3) dissolved oxygen at the condensate pump discharge must be less than 10 ppb to minimize the cumulative inventory of corrosion product transported from the condensor to the steam generator; (4) continuous monitoring and control of the chemistry of the steam generator blowdown must be performed; measured values must be compared to theoretical values in order to identify whether or not excess alkalinity or acidity is present; (5) copper and nickel bearing alloys must be eliminated from the secondary system to

permit greater flexibility and optimization in chemistry control; (6) main condenser integrity must be upgraded to minimize the ingress of impurities to the condensate in order to improve the reliability of the steam generators and balance of plant; and (7) if a full-flow condensate polishing system is installed, it must be carefully controlled and properly operated in order to optimize the quality of the treated condensate. (Findings, 160 .)

The so-called EPRI Guidelines were developed under the aegis of the Steam Generator Owner's Group (SGOG). These guidelines incorporate more restrictive water chemistry controls than the Westinghouse guidelines and include a staged corrective action plan for reducing corrosive products when they exceed minimum levels established by the guidelines. In addition to the more restrictive water chemistry controls, the EPRI Guidelines include recommendations for data management, surveillance, and analytical methods which must be adhered to if the secondary water chemistry control program is to be successful. The EPRI Guidelines include a recommendation that specific management responsibilities regarding secondary water chemistry control <u>be assigned from the plant chemist to senior corporate management</u>. (Findings, .)

In addition to the Westinghouse Guidelines noted above, the Byron Station Chemistry Monitoring Program must

incorporate the following elements from the EPRI Guidelines: (1) more restrictive EPRI water chemical controls coupled with a corrective action plan to require prompt station response to a chemistry excursion before unit shut-down is required; (2) a staged corrective action plan based upon the level and duration of contaminant ingress; requiring specific corrective actions, including staged reductions in power; (3) a data management and surveillance program providing for prompt identification of negative trends or inconsistencies in chemical control data; (4) an analytical program to supplement and verify the daily on-line chemistry monitoring system data. Although not specifically included in the Byron Chemistry Monitoring Program, the statement of management responsibilities recommended in the EPRI Guidelines is being addressed in a Commonwealth Edison corporate PWR Secondary Water Chemistry Control Program. This program must be completed, tested, evaluated, and composed to the guidelines if it is to be consistant with the guidelines . (Findings, 162 .)

There have been numerous occurences of corrosion mechanisms in plants where AVT has been the exclusive water chemistry control. One plant experienced pitting of the Inconel tubing which is believed to be due to an acidic chloride condition involving copper and chloride ions. There have been a small number of stress-corrosion cracking incidents. Denting has also occured in plants operating

strictly with AVT water chemistry. (Findings, 163 .)

The rupture at Point Beach was caused by secondary side intergranular stress corrosion cracking which occured as a consequence of reactions between condenser inleakage impurities and residual phosphates, containing excessive alkalinity. (Findings, 164 .)

Byron will use all volatile chemistry treatment; consequently, the specific chemical reactions which caused the Point Beach rupture should not occur at Byron. Since the industry conversion to AVT in 1974, no plant which has started up on AVT has operated long enough to detect secondary side initiated stress corrosion cracking. (Findings, 165 .)

The rupture at Surry was initiated from the primary side of the tube and caused by excessive tube stress. (Findings, 166 .)

The excessive tube stress resulted from extensive tube denting which first froze the tube in place and then physically moved the tube support plates, resulting in a significant deformation of the tube and resultant high stress. (Findings, 166 .)

Conway used an illustration of flow slots on the upper tube support plate to demonstrate how density caused hourglassing of tube flow slots in the upper tube support plates thus pinching the support plates and in turn pinching the tubes; thus compressive stresses induced by pinched tubes caused stresses at the U-bend. On the D-5 the widest spacing

functionally possible between tube support plates was selected. The holes in the flow distribution baffle plates and in the top tube support plate were modified to a circular design instead of a rectangular slot. This minimized the tube stresses further, making the tubes less suseptible to the denting which could occur in the D4 Unit. (Findings. 167 .)

The hydraulic tube expansion technique for expanding tubes at the tubesheet was used only for Unit 2 Model D-5. The tube expansion technique used for unit one was mechanical dialtion techniques with greater inherent residual stresses. (Findings, 168 .)

A form of tube thinning has also been observed at lower tube support plate elevations around the periphery of the bundle at two all-AVT plants. The cause of this thinning has not been conclusively identified. (Findings, 169 .)

Plants that have only operated on AVT have experienced some denting. (Findings, 170 .)

Denting is a localized radial reduction in the diameter of steam generator tubes, resulting from corrosion of the carbon steel tube support plates in the tube-tube support plate annulus, as in the D-4 Model. (Findings, 171 .)

Another source of denting identified through field tests is the condenser in -leakage of contaminants from the

tertiary water system such as copper, nickel, oxygen, and chloride ions. (Findings, 172 .)

The 1977 Westinghouse AVT Guidelines advocated rigorous control of the condensate and feedwater chemistries during both shutdowns and power operation to reduce secondary system corrosion and transport of the corrosion products into the steam generators. (Findings, 173 .)

Concentrations of chloride in the levels of thousands of parts per million can build up in the tube support crevice even though chloride levels in the bulk steam generator solution are only at the parts per billion level. (Findings, 174.)

Chloride levels on the order of thousands of parts per million (ppm) have been seen in the corrosion deposits in the tube support plate crevice. (Findings, 175 .)

No method has been developed for determining the concentration of corrodants contained in the tube support plates annulus where denting is known to occur. A complete sample of the chemical solution contained in the tube support plate crevice has never been taken. Neither is there any empirical evidence on the concentration of corrodants at the tube support plate coeurces or the minimum concentration of corrodants necessary at the crevice for corrosion to occur or to rapidly propagate. Thus, in operation, it would not be possible to conclusively determine what concentration value in the bulk water solution would lead to excessive corrosion,

nor the corrosion product volume and rate which would lead to tube leaks between inservice inspections. (Findings, 176 .)

The guidelines themselves don't even indicate format for reporting violations; that is left to the utility. Violations or failures to adhere to the water chemistry guidelines to be followed at Byron will be reported only on an annual basis to the Nuclear Division Vice President. (Findings, 177 .)

There is no requirement anywhere to report violations of the water chemistry guidelines to the NRC office of Inspection and Enforcement. (Findings, 177 .)

Status has changed on 44 steam generator procedures applicant is developing and identified in November 1982. Edison has stated it will complete all procedures before Byron fuel load, including secondary chemistry program descriptions and chemistry procedures. Following completion of procedures, all procedures will have to undergo extensive testing and systems analysis to ensure they do not cause a deviation from the secondary water chemistry guidelines. (Findings, 178 .)

When asked why he recommends that Byron operating chemistry procedures should be reviewed by an independent body, Bridenbaugh says that NRC's ITE branch and resident inspector do not have all the necessary resources or skills to conduct an independent review. Their review is merely to assure that proper procedures are in place and is limited to the assurance

that the procedure is identified, followed and complied with. (Findings, 179 .)

This review was not done when EPRI and SGOG drafted guidelines. Bridenbaugh says NO! He says they are just guidelines. He's talking about a review of plant specific chemistry monitoring equipment and procedures to ensure the guidelines are indeed being implemented to greatest degree possible. An operating license should not be issued until this is done. (Findings, 180 .)

Tube rupture events.

Mr. Bridenbaugh testified that there is an increased probability that accidents will be initiated by tube failures during normal operation and an increased likelihood that accidents not now considered in the safety analysis may occur as a result of the steam generator tubes degradation after some period of operation. The accident sequence could involve single or multiple tube failures occuring in conjunction with other accident sequerces. (Findings, 181 .)

Mr. Fletcher assimilated the conclusions provided by the Applicant's expert witnesses testifying with respect to their specific disciplines and reached an overall assessment as to steam generator tube integrity at the Byron Station. Based upon the design, water chemistry, detection and remedial measures undertaken by Applicant, Mr. Fletcher concluded that steam generator tube degradation at the Byron Station should not be a safety concern and that tube rupture should not occur, even under conditions of Main Steam Line Break (MSLB) or Loss of Coolant Accidents (LOCA's). However, Mr. Fletcher's

conslusion is based on the limited operational experience of steam generators with AVT water chemistry, highly limited testing of new systems for detection such as the loose parts monitoring system, and a technical fix for the flow induced vibration problem which has not been fully tested for its adequacy in an operational steam generator. A Byron specific PRA which considers tube ruptures and LOCA has not been done. The effect of the steam generator tube rupture upon a large MSLB, MFLB and LOCA have been considered by the Staff, but the Staff's multiple steam generator tube rupture analysis has not been published and is still under staff review. (Findings, 183 .)

The consequences of a large MSLB inside containment could be adversely affected by such an event. Calculations have shown that provided there are no additional events such as operator error or safety valve failures, containment integrity should be effected, the core should remain covered and cooled due to the addition of emergency core cooling, and there should be ample water supply available for long term cooling. However, if operator error and/or safety valve failure changes the accident sequence, the MSLB could be adversely affected and subsequent tube ruptures are possible. (Finding 187)

Calculations have been performed to evaluate the systems performance, offsite radiological consequences and required operator actions assuming a steam generator tube rupture concurrent with an MSLB outside containment. These studies evaluate the effects of a main steam line break combined with one or five ruptured steam generator tubes in a small break LOCA, only. Calculations have not been performed for multiple tube ruptures occuring with a medium or large LOCA and improper depressurization of the steam generator,

and/or improper valve functioning. (Findings, 188 .)

A series of LOCA experiments with varying degrees of simulated tube failures performed in the semi-scale facility at the Idaho National Engineering Laboratory several years ago confirmed the general behavior involved in small LOCA accidents. (Findings, 189 .)

These experiments did not show the same degree of degraded core cooling as the computer analysis did for the worst cases. In fact, the experiments did not indicate that any core damage would occur. (Findings, 189.)

The overall consequences of a large MFLB with simultaneous steam generator tube rupture were bounded by the combined MSLB and tube rupture inside or outside containment.

The Staff does not postulate one of these events combined with the steam generator tube rupture as a design basis event as it does not believe they pose an undue rusk to public health and safety. (Findings, 190, 191.)

The MSLB, MFLB and cold and large cold leg break LOCA accidents have been calculated to be low probability events on the order of 10^{-5} to 10^{-6} per reactor year. However, this is a probability assigned to an individual reactor, and must be multiplied by the number of reactor years for the industry as a whole to determine a industry wide probability. The steam generator tube rupture event, while not as infrequent as the LOCA, MSLB or MFLB accidents, is also an infrequent event on the order of 10^{-2} to 10^{-3} per reactor year. (Findings, 192, 193.)

The results of these analyses indicate but do not conclusively prove that primary coolant shrinkage, caused by overcooling, and the simultaneous loss of primary coolant, can be compensated by the high pressure emergency core cooling system. The core should remain covered, and the primary coolant remain cool, except in the vessel upperhead. The calculations and results are desc. ibed in NUREG-0937. However, these calculations assume no operator error, inadvertent valve failures and/or rapid depressurization of the secondary side, occur and do not lead to further tube ruptures and/or a MFLB. As part of the technical resolution of the steam generator tube integrity unresolved safety issue, the Staff assessed the consequences of single and multiple tube breaks (in a single steam generator) concurrent with a large main steam line break or large cold leg break LOCA. (Findings, 194, 195.)

One of the main purposes of this effort is to develop a statistically based inservice inspection program that affords a high degree of assurance that if a large MSLB or LOCA occured concurrent with ruptured steam generator tubes in the effected steam generator, the offsite radiological dose would not endanger the public health and safety and the fuel cladding temperatures would remain within the limits of Appendix K to 10CFR. (Findings, 196.)

The consequences of a large, cold leg LOCA could be adversely affected by the flow of steam generator fluid into the primary loop through the broken steam generator tubes. Several computer studies performed over the years indicated the following: (1) rupture of a few tubes during a LOCA would have very little effect, (2) if a large number of tubes ruptured, the additional fluid flow into the reactor vessel during a large break

would actually aid in cooling the core, and (3) an optimum number of tubes over a limited range (about 12) or (1200 psi break) could have a detrimental effect. However, it is not expected to lead to a core meltdown, provided that the emergency core cooling system operates as it should, and the emergency S6 operating procedures are rigorously adhered to. (Findings, 197 .)

The Applicant performed an analysis whereby it predicted that tube rupture events in combination with accidents are predicted to result in severe core damage at frequencies of 10^{-7} per year for the Byron Station. However, there is a great degree of uncertainty in this estimate which geometrically escalates with each additional S6 tube rupture. By this calculation, a single tube rupture would occur about once every 33 years at Byron, but multiple tube ruptures could become more probable as the degree of uncertainty in the analysis geometrically escalates. (Findings, 198 .)

Goldberg asks Bridenbaugh if the Byron FSAR analysis postulates failure of one tube and only 1 gpm leakage, and whether he believes that? Bridenbaugh says no - he believes it could be as high as 760 gpm since that was what was seen from the single-tube failure at Ginna. With a 760 gpm break, only 2 tubes would have to rupture to reach the 1200 psi at which equilibrium between primary and secondary side break flow should be reached. (Findings, 199 .)

Bridenbaugh explains how multiple tube failure could occur, with a Ginna precursor as initiator. (Finding 200)

As part of the Staff's ongoing evaluation of the four domestic steam generator tube ruptures and steam generator tube degradation in general, a number of specific requirements are being considered. Twelve

potential requirements are presently undergoing cost-benefit assesment by the Staff and its consultant. The consultant cost-benefit assessment is contained in a final draft report, the S.A.I. report, entitled "Value Impact Analysis of Recommendations Concerning Steam Generator Tube Degradation and Rupture Events" (marked for identification as Intervenor's Exhibit 9 at Tr.4443.) These items are under consideration as potential Staff requirements. The Staff has continued to evaluate these recommendations since the issuance of the consultant report, and has modified, altered and changed the majority of the recommendations. It is entirely possible that the committee for the review of generic requirements will do the same. A number of other items are also being considered as Staff actions. (Findings, 202 .)

Gallo questions NRC witnesses on their judgement of whether or not they are going to recommend that the potential requirements in S.A.I. report be proposed as requirements. Each witness answers only with respect to his division's recommendations, because there currently is not staff position on each of these requirements and they must still await CORGR and ACRS review before being proposed as requirements. (Findings, 203 .)

Marsh states that the S.A.I. recommendations and NUREG-0844 will probably be appendices to a long memorandum on the requirements which must be implemented,and this memo will go to Licensses and Applicants. The requirements would be in the form of a 10CFR 50.54 letter that allows agencies to require changes in the Standard Review Plan. (Findings, 204 .)

Pages 4733-4750 of the Transcript of this proceeding enumerates the potential requirements in the S.A.I. report that the Division of Systems Interaction and Engineering, the Division of Engineering, and the Division

of Safety Technology in the NRC all agree be recommended for implementation. (Findings, 205 .)

Marsh states that the S.A.I. requirements are to a great extent already implemented at Byron and that there is no consideration to exclude any plant from backfitting requirements of NRC via S.A.I. review. But the final requirements will not be finalized until the committee for review of generic requirements, and ACRS have reviewed the Staff's recommendations. Therefore, it is not possible to conclude that the changes which have been made at Byron will allow the plant to meet the final requirements without further plant modification. (Findings, 206 .)

Marsh testifies that the S.A.I. report is still under staff review and is not yet complete. However, he anticipates formulation of overall recommendations to be forwarded to the committee for review of generic requirements towards end of May. But several steps have yet to be completed before S.A.I. recommendations become requirements, including ACRS and commission review and a public comment period. (Findings, 207)

As a result of the TMI accident, TMI action plan 1.C.1 requires the industry to upgrade emergency operating guidelines and procedures to cover multiple failure events which fall outside the required design envelope assumptions for safety analyses. (Findings, 208)

These events were not analyzed in order to show conformance with existing regulations. The idea was to develop emergency operating procedures that go well beyond the design basis accidents in the remotest possibility that they could occur. (Finding 210)

In this context, the Staff and vendors are analyzing a variety of such events, including coincident steam generator tube ruptures and LOCAs and coincident steam generator tube rupture and steam line breaks. The results of a recent Staff analysis are discussed in NUREG-0937. (Findings 211)

The S.A.I. Report did not perform its own multiple tube failure analysis but did review NRC's MFTA. A Byron specific multiple tube failure analysis has not been conducted to ensure that the calculated probability risk at Byron is within the range calculated for the generic analysis. (Findings, 212, 184.)

After TMI, and the concern for improved operating procedures, the Westinghouse Owners Group undertook a generic development of guidelines to cover all emergency operating procedures. These generic guidelines have been submitted to the NRC for approval. (Findings 209, 213)

The Westinghouse generic emergency response guidelines have been used as a basis for the development of the Byron operating procedures. (Findings 214)

Emergency operating procedures being developed should help the Byron operators to respond to the various compound accidents discussed at the hearing once they occur, provided that Byron specific procedures are adequately tested by computer simulation and the operators are thoroughly trained to allow an expedited use of these procedures in the event of an accident. (Findings, 214 .)

Unresolved Safety Issue A-3.

USI A-3 is an unresolved safety issue which will not be fully resolved by the NRC for several more months. (Findings 226)

A primary objective of the steam generator USI program is to ensure that tubes are plugged before they corrode to a significant degree that they have potential for rupturing in subsequent operation. (Findings, 227)

The objective of the program is to control degradation to enable the maintenance of tube wall integrity under both operating and accident conditions. (Findings, 227)

In Staff and Applicant's opinion, despite the retention of USI A-3 an an unresolved safety issue, the dimensions of the more typical tube degradation have been reduced. (Findings 228)

A graph prepared by EPRI, and endorsed by the Staff, shows the relative number of tubes plugged verses the total number of tubes in service between 1972 and 1980. This graph shows the number of tubes that plugged due to phosphate wastage or thinning, denting, and other related problems. The graph demonstrates that 1977 was the height of its denting problem. This is when the Surry steam generators and Turkey Point steam generators went through so much tube plugging they had to be replaced, and then, of course, ceased to be a problem. (Finding 229)

Once identified in 1976 and 1977, after the shift to all volatile chemistry, the industry became aware of what it took to reduce denting, and a decrease in the amount of denting and other corrosion in all units was seen. This specific trend has continued to the present. (Finding 230)

Things were continuing to get better and the industry was, in fact, doing what it needed to do to resolve steam generator corrosion, in fact, doing what it needed to do to resolve steam generator corrosion problems, till

flow-induced vibration came to complicate things. (Finding 231)

Staff resolution of the issue is not complete. It is almost exactly at the same point as in 1981 when they said it would be resolved in early 1982. Staff has estimated previously the time of resolution of task A-3 and been in error. NUREG-0886 estimated early 1982. Staff now says it will be done by mid-1983. The Ginna event has delayed resolution by introducing need to consider multiple tube failures. The recommendations in NUREG-0651 are also included in Staff's generic program as is Nureg-0844, a draft document, not yet final. Finding 232 (Finding 233-2

There are no recommendations contained in Nureg-0844 that have not been the subject of evidentiary examination in this hearing. Further, all in 0844 are embodied in the NRC's current set of recommendations. (Finding 235)

The decision as to whether NRC requirements developed as part of the resolution of USI A-3 must be retrofitted into operating nuclear power plants is a decision that must be made by the Committee for the Review of Generic Requirements. There is no consideration at this time to exclude any plant from backfitting in order to meet the NRC's requirements to resolve USI A-3.

(Finding 236)

Conclusion

Eleven issues and sub-issues were reviewed in this proceeding with regard to the Byron plant: corrosion-related degradation, steam generator design, pre-service and inservice inspection, primary to secondary leak rate limits, water chemistry, tube plugging, loose parts and flow-induced vibration, tube rupture events and accident considerations, and the over-all resolution of NRC Unresolved Safety Issue A-3, steam generator tube integrity.

The Board finds that corrosion-related degradation will still continue at Byron. Although Unit 2 is a D-5 with additional design margin over previous models, no Westinghouse steam generator model has been totally exempt from corrosion-related degradation, and relatively little operational experience exists with either the D-4, or D-5 models to preclude it's occurrance at Byron. Further, the Board finds that, in many respects the D-4 model of Unit 1 is not enhanced against degradation. (Findings, 16, 17, 23-26, 27, 28, 33-35)

The Board finds that the steam generator tubes at the Byron plant may be more suseptible to tube degradation in the long run, due to fabrication defects on selected tubes at or about the level of baffle-plate in the preheater section in row one tubes, a suspected area for service-induced dents and cracking at the apex of U-shaped tubes. (Findings, 134-140)

ALARA is always a consideration for a proposed modification. The Board finds that Applicant's committment to implement the proposed Westinghouse modifications at Byron prior to operation be made into a license condition due to the substantial ALARA Considerations if that modification is not installed prior to an operating license. Futher, as there exists the possibility that Byron, and not Comanche Peak may be the first operational plant utilizing the Westinghouse proposed D-4, D-5 modifications, the Board also finds it a license condition that

finds it a license condition that Applicant instrument the steam generators of both units with accelerometers to monitor tube vibration levels on an on-going basis, and demonstrate the development of a special inspection program to ensure safe operation of the plant. (Findings, 57,58,69,70-86)

The Board finds that a review of the Byron plant specific chemistry monitoring equipment and procedures should be conducted by an independent body prior to plant operation to ensure that the EPRI and Westinghouse guidelines are being implemented to the greatest degree possible by Applicant. (Findings, 173-180)

The Board finds that as the loose parts monitoring system is not an active system, is there for periodic monitoring, and is not require as a limiting condition for operation, be tested at Byron prior to operation to ensure it's operational effectiveness, accurate calibration, and incorporate the generic surveillance requirements currently undergoing Staff development and review. (Findings, 106-113)

The Board finds that Applicant has failed to comply with 10 C.F.R. 50.57 (a) (3) as implemented with respect to steam generators by satisfying General Design Criteria 30 and 31, wherein Applicant must demonstrate that design measures (such as the technical fix for flow-induced vibration), fabrication methods and operational proceedures (such as the program for adherence to water chemistry guidelines) have been developed and tested; and that detection systems are in place (such as the loose part monitoring system) so that under either normal or under accident operating conditions there is an extremely low probability of abnormal leakage, of rapidly propagating failure, of gross rupture of tubes becoming so brittle that their degraded condition would eventuate in the above.

Additionally, the Board finds that NRC Staff has failed to provide adequate explanation why the operation of the Byron plant can proceed in ad-

of an over-all solution of unresolved safety issue A-3, insofar as Staff has failed to conduct an adequate independent investigation of Westinghouse's proposed modification for flow-induced vibration relating to steam generator tube integrity, so as to justify their conclusion that the basis of their preliminary review of the modifications is sufficient to ensure the public health and safety under plant operation. (Finding 223)

FINDINGS OF FACT

* * * *

Rockford League of Women Voters' (League) Contention 22 and DAARE/SAFE Contention 9(c) -- Steam Generator Tube Integrity

1. Rockford League of Women Voters' (League) Contention 22, as litigated, provides:

> An extremely serious problem occurring at other plants such as Consumers' Palisades plant and C.E.'s Zion plant, and likely to occur at C.E.'s Byron plant, is presented by degradation of steam generator tube integrity due to corrosion induced wastage, cracking, reduction in tube diameter, and vibration induced fatigue cracks. This affects, and may destroy, the capability of the degraded tubes to maintain their integrity, both during normal operation and under accident conditions, such as a LOCA or a main steam line break. The Commission Staff has correctly regarded this problem as a safety problem of a serious nature, as evidenced both by NUREG-0410 and the Black Fox testimony cited above. As a result of this serious and unresolved problem the findings required by 10 C.F.R. §§ 50.57(a)(3)(i) and 50.57(a)(6) cannot be made.

DAARE/SAFE Contention 9(c) as litigated, provides:

> Steam generator tube integrity. In PWRs steam generator tube integrity is subject to diminution by corrosion, cracking, denting and fatigue cracks. This constitutes a hazard both during normal operation and under accident conditions. Primary loop stress corrosion cracks will, of course, lead to radioactivity leakes into the secondary loop and thereby out of the containment. A possible solution to this problem could involve redesign of the steam generator, but at FSAR, Section 10.3.5.3 the Applicant notes its intent to deal with this as a maintenance problem which may not be an adequate response given the instances noted in Contention 1, above.

2. To address the contentions, Applicant presented the testimony of eleven witnesses. Mr. John C. Blomgren, of Commonwealth Edison Company, addressed various measures that will be employed at the Byron Station to minimize steam generator tube degradation. Dr. Mahendra R. Patel, of Westinghouse Electric Corp., addressed the "leak-before-break" principle and steam generator tube plugging criteria. Other witnesses from Westinghouse

included Mr. Daniel Malinowski, who addressed the inspection measures used to detect steam generator tube degradation; Dr. Michael J. Wootten, who addressed the water chemistry measures used to minimize tube degradation on the secondary side of the steam generators at Byron; Dr. Lawrence Conway, who addressed the design changes in D4 and D5 steam generators at Byron; and Mr. Thomas Timmons, who addressed the flow-induced vibration phenomenon. Mr. Lawrence D. Butterfield, of Commonwealth Edison, addressed Applicant's modifications with respect to the flow-induced vibration phenomen. Applicant also presented the testimony of Mr. Kenneth J. Green, Mechanical Project Engineer for Sargent and Lundy Engineers, who addressed the issue of whether the proposed modifications to the Byron steam generators described by Messrs. Timmons and Butterfield might increase the liklihood of a waterhammer event in the Feedwater Bypass Systems of the Byron steam generators, and Mr. Rodolfo Paillaman, a Senior Quality Assurance Non-Destructive Examination Specialist with Ebasco Services, Inc., who addressed the pre-service inspection of the steam generator tubes at Byron.

Mr. Wilson D. Fletcher, Manager of Steam Generator Materials and Chemistry of Westinghouse, provided an overview of the steam generator tube integrity issue and Mr. Michael Hitchler, Manager of Probabilistic Risk Assessment with the Nuclear Safety Department of Westinghouse, quantitatively assessed the probability of steam generator tube ruptures under various conditions.

The NRC Staff presented the testimony of Dr. Jai Raj N. Rajan, a mechanical engineer, who addressed the flow-induced vibration phenomenon and the probability of tube rupture under various conditions; Mr. Ledyard B. Marsh, who addressed various steam generator tube degradation issues;

Mr. Louis Frank, a senior materials engineer, who addressed secondary side water chemistry measures and inservice inspections; and Mr. Conrad McCracken, who addressed steam generator design and secondary side water chemistry measures to reduce corrosion.

The League presented the testimony of Mr. Dale G. Bridenbaugh, a nuclear engineer and President of MHB Technical Associates in California, who addressed various aspects of steam generator tube integrity issues concerning the Byron Station.

3. The steam generator tubing, which is part of the reactor coolant pressure boundary, represents an integral part of a major barrier against the release of radioactivity to the environment. Accordingly, design criteria for tube wall sizing have been established to assure structural integrity of the tubing under normal operating and the postulated design-basis accident condition loadings. (Patel, Applicant Prepared Testimony at 5, ff. Tr. 4126).

4. Steam generator tubes are manufactured to a wall thickness of approximately .042 . (Id. at 6; Patel, Tr. 4370).

5. However, the operating experience of PWRs has shown that over a period of time under the influence of the operating loads and environment in the steam generator, steam generator tubes may become degraded and leak. (Patel, Applicant Prepared Testimony at 6, ff. Tr. 4126; Malinowski, Applicant Prepared Testimony at 5, ff. Tr. 4126).

6. Tube degradation problems at Westinghouse steam generators have included the following: wastage and thinning corrosion, denting, pitting, intergranular attack, stress corrosion cracking, wear caused by flow-induced vibration, and wear and or impact damage as a result of foreign objects or loose parts. (Frank Testimony, ff. Tr. 4473, at 2).

7. Tube wall thinning is a localized reduction in the tube thickness resulting from corrosion by phosphates in high concentrations. It is caused by low sodium to phosphate ratio solutions. (Wootten, Applicant Prepared Testimony at 8, ff. Tr. 4126). Tube wall thinning has been observed within sludge piles at the top of the tubesheet and at tube support plant elevations, where lower flow velocities allowed concentration of phosphates to saturation levels. (Malinowski, Applicant Prepared Testimony at 15-61, ff. Tr. 4126).

8. Thinning occurred in the earlier days of plant operation when plants were operating on a phosphate chemistry. The thinning of the tubing was associated to a concentrated solution of sodium phosphate which was the corrosive agent that caused the thinning of the tubing. (Id.).

9. The change to all volatile treatment (AVT) water chemistry controls mitigated the thinning of the steam generator tubing caused by acidic phosphate species. (Wootten Testimony, ff. Tr. 4126, at 10).

10. Thinning has been reduced to the point where it vanishes as a major contributor in plants that have switched to AVT. (Tr. 4172-73 (Wootten)).

11. While the change to AVT mitigated thinning caused by acidic phosphate species, in the immediate years following the conversion to AVT, another form of corrosion called "denting" was observed with AVT use. (Wootten Testimony, ff. Tr. 4126, at 10).

12. Denting is a process whereby corrosive impurities are concentrated between a heat transfer tube and a tube support. The resultant corrosion converts the base support metal to metal oxide. (McCracken Testimony, ff. Tr. 4473, at 6).

13. Denting is due to corrosion of the carbon steel support plates. Denting does not directly result in steam generator tube corrosion. It

simply deforms the tube which increases the tubing stress. (McCracken Testimony, ff. Tr. 4473, at 7).

14. As tubes become more highly stressed, they are more susceptible to stress corrosion cracking. (McCracken Testimony, ff. Tr. 4473, at 7; Tr. 4519 (Frank)).

15. Plants that have only operated on AVT chemistry have had less severe denting and in some cases where these changes have been adopted vigorously, the progression of denting has been arrested. (Wootten Testimony, Tr. 4126, at 13-14).

16. Byron Unit 1, D-4 Model steam generator will have carbon steel support plates. Unit 2, D-5 Model will have ferretric stainless steel support plates.

17. Denting will still occur at Byron Unit 1. It will take from 3-10 years for initiation, depending on how well the water chemistry guidelines and condenser inservice inspection program are adhered to. (Tr. 4771-4772).

18. Pitting is a form of tube degradation that involves small discrete roughly circular regions of tube penetration typically less than 100 mils in diameter. Pits may occur separately or in bands wherein each pit sits independently of others within the band. (Patel Testimony, ff. Tr. 4126, at 16-17).

19. One plant (Indian Point) experienced pitting of the Inconel tubing which is believed to be due to an acidic chloride condition involving copper and chloride ions. (Wootten Testimony, ff. Tr. 4126, at 14). This incident was caused by excessive condenser inleakage, oxygen inleakage and the

combination acting on a copper alloy condenser and feed train over a protracted period of time. (Tr. 4803 (McCracken)).

20. Stopping condenser inleakage is an absolute measure to stopping corrosion. The NRC is considering making it a requirement that condensers be inspected routinely as steam generators are. (Tr. 4536).

21. Tube wall cracking generally occurs in a local region and the crack may extend through the entire wall thickness. Depending upon the orientation of tube wall stresses, cracks may initiate from the outside diameter or the inside diameter of the tube. All tube stress-corrosion cracks detected in Westinghouse-designed steam generators have been intergranular in nature. Intergranular attack is a form of tube degradation usually characterized by general grain boundary dissolution. It occurs in conjunction with stress-corrosion cracking on the outside diameter of the tube; it usually occurs within crevices between the tube and the tubesheet. (Malinowski, Appl. prepared Test. at 17-18, 20 ff. Tr. 4126.)

22. Tube wear is a form of tube degradation that results from a mechanical abrasion of the tube surface. Such wear progressively reduces the thickness of the tube area affected. Wear results from the impact of adjacent structures or loose objects on the tubing; it has been observed at antivibration bar intersections, the baffle plates in preheat sections and locations in contact with foreign objects. (Malinowski, Appl. Prepared Test. at 21 ff. Tr. 4126.)

Steam generator design.

23. Both Byron Unit 1 and Byron Unit 2 have preheat steam generators which are functionally identical. Byron Unit 1 is a model D-4 and Byron Unit 2 a model D-5. The difference between these designs occured as part of the normal evolution over time of steam generator designs. (Conway testimony, ff.

Tr. 4126, at 13-14).

24. Inconel 600 was chosen for the steam generator as tubing being the most suitable material available for the temperatures, chemical environment, and design basis accident conditions present within the steam generator. To reduce chemical concentrations areas such as at the tube sheet and between the tube and tube support plate, recirculation rates were increased, the ports in the blowdown pipe were modified, and the tubes within the tube sheet hole were expanded to eliminate the crevices at the tube sheet. (Conway Test., Tr. 4126 at 14, McCracken Test. Tr. 4473, at 2.)

25. To minimize the tube stresses, the widest space in between tube support plates which is functionally acceptable was selected, the holes in the flow distribution baffle plates and in the top tube support plate were modified. (Conway Test., ff. Tr. 4126, at 14-15; McCracken Test., ff. Tr. 4473, at 2.)

26. In addition, the design of the Model D-5 in Unit 2 has been enhanced over the D-4 in Unit 1 by (1) utilizing stainless steel, a more corrosion-resistant material, as the material for the tube support plates and baffles, (2) changing the shape of the holes in the tube support plates from circular to a quatrefoil shape to improve flow, (3) expanding the tubes within the tube sheet by means of a hydraulic device in lieu of mechanical rollers to reduce stresses, (4) thermally treating the Iconel 600 tubes to enhance resistance to corrosion, and (5) changing the holes in the flow distribution baffles from slotted to a circular shape to improve flow. (Conway, Appl. Prepared Test. at 14-15, ff. Tr. 4126; Fletcher, Appl. Prepared Test. at 6-7, ff. Tr. 5908.)

Flow-induced vibration.

27. Since 1981, a design problem with flow induced vibration and subsequent wear of tubes in the preheater section of Model D steam generators

has been identified at lead operating facilities with Model D steam generators. (Rajan Test. ff. Tr. 4473, at 1; Timmons Test. ff. Tr. 5908, at 8.)

28. These include McGuire Nuclear Station, Unit 1 (Model D2) and the following three foreign facilities: Ringhals, Unit 3 (Model D3), Almarez Unit 1 (Model D3), and Krsko (Model D4).

29. Certain tubes in the preheater region of the steam generator vibrate against the baffle plates as a result of the turbulence created by the feedwater flow entering from the main feedwater nozzle. (Timmons, Appl. Prepared Test. at 8-9, ff. Tr. 5908.)

30. The tube excitation mechanism appears to be a combination of a threshold type of fluid elastic instability and turbulent buffeting. (Rajan Test. ff. Tr. 4473, at 2.)

31. The oscillating drag forces are produced in large measure by the presence of the impingement plate and the flow held that that plate creates unsteadiness of the flow field in inlet plenum. (Timmons Tr. pg. 6087.)

32. Model D4 and D5 steam generators employ counter flow type preheater design. The split flow design is employed for Model D2 and D3 steam generators. (Rajan Test., ff. Tr. 4473, at 2; Timmons Test., ff. Tr. 5908, at 5.)

33. Tube wear in Model D steam generators resulting from flow-induced vibration was initially identified in Sweden at Ringhals Unit 3, a plant with Model D-3 steam generators in October 1981. The degradation was in the form of a through-wall hole in a single tube at a baffle plate. Eddy current testing performed also indicated tube wall wear in outer 3 rows of preheat or tubes. (Timmons, Tr. 5908, 5913, 5918.)

34. Ringhals had operated at 100% power, 100% main feed for only 2,000 hours when the tube leak occured. (Tr. pg. 5912.)

35. Possible tube wear was also detected at another D-3 plant, Almarez

1 which had operated only 1,500 hours at 100% power in October 1981. (Timmons, Tr. 5908,5913.)

36. Eddy current testing was also performed at McGuire 1, a domestic plant with Model D-2 steam generators and at Krsko, a non-domestic plant with Model D-4 steam generators. No indications were found. The latter two plants had not operated above 50% power, McGuire operations for only 1,000 hours and Krsko for 300 hours at 40% power. (Timmons, Tr. 5908, 5915.)

37. Based upon the early eddy current testing indications, Westinghouse started a program to investigate, understand and define vibration and tube wear in Model D steam generators using and reviewing tube wear data from operating plants and from model tests to conceive, develop,test, evaluate any modifications necessary to allow operation of Model D steam generators at full power. (Timmons test. ff. Tr. 5908 at 9-10.)

38. Accelerometers were placed in the McGuire, Almarez, Ringhal, and Krsko plants between December 1981 and March 1982 to try to correlate tube vibration data to tube wear data to predict potential tube wear over same operating period. (Timmons Tr. 5932-5934, 5937.)

39. The Accelerometers at Krsko were placed in the 4 tubes thought to be the ones that would be most susceptible to tube vibration, and would exhibit the highest levels of vibration. (Timmons, Tr. 5945.)

40. May of 1982 one tube was removed at Krsko. It had 6% tube wear in one location and 1% in another. This was also one of the tubes in which an accelerometer was placed. (Timmons, Tr. 5951.)

41. Krsko shut down again in late October 1982. Two previously instrumented tubes were removed and one tube expanded. The two removed tubes had wear indications of 2-4%. Krsko began again in November. Accelerometers were installed in the expanded tube. Vibration data was gathered at this

point for various feedwater flow configurations. (Timmons, Tr. 5987-5989.)

42. At the time, October 1982, these feedwater flow configurations were used to take accelerometer data and measure changes in vibration levels with changes in main feedwater into main nozzle, Krsko had only between 24 and 48 hours at 100% main nozzle flow. (Timmons Tr. 5956.)

43. The tubes removed in October from Krsko were used to determine whether flow levels of vibration resulted in any demonstratable amount of wear and the vibration boundaries of the tube bundle. They demonstrated that tubes with a high level of vibration generally suffered only a little bit more wear over extended periods of time than tubes with a low level of vibration. (Timmons Tr. 5957-5958.)

44. The vibration data from Krsko collected at various power levels and various combinations of main feed and bypass feedflows showed that the tube vibrations of the 70% main feed/30% bypass feed combination were slightly greater than those of the 70/0 combination and that the vibrations observed at 70/30 were acceptable. (Timmons Test. ff. Tr. 5908, at 15.)

45. Correlations of tube wear with vibration is a very complex function. 90% or 100% main feedflow through the main nozzle contributes much more significantly to wear function than operation at lower power levels. "It is a strong function of the amount of flow." (Timmons Tr. 5978-5979.)

46. Collected data indicating that high main feed flow rates with unexpanded tubes could produce significant vibration of some tubes, resulting in greater wear than at lower feed flow rates. (Timmons Tr. 5958.)

47. The tube vibration data obtained from use of the expanded tube at Krsko indicated that the tube vibrations in both steam generators were similiar and had not changed with time. The expanded tube had been previously instrumented for vibration and reinstrumented. Previous tube vibration

data was compared with the data obtained after the tube had been expanded and it was concluded that the tube vibrations were reduced by at least a factor of 5 from the nonexpanded tube. (Timmons Test. Tr. 5908 at 14.)

48. As part of the generic Model D4/D5 program, a 16° full scale model was used to replicate in the laboratory the tube vibration response observed in operating steam generators. A single tube vibration model was used to characterize tube response under various excitation and support conditions. (Timmons Test. ff. Tr. 5908 at 19.)

49. In the 16° model, a number of tubes were expanded and testing was conducted to determine the effect of tube expansion on tube vibration. At a flow rate equivalent to 90% of the Byron main feed flow rate, the expanded tubes exhibited vibration levels that were less than those observed at flow rates equivalent to 70% of the Byron main feed flow rate without tube expansion. (Timmons, Test. Tr. 5908 at 26.)

50. The model tests were all run at cold conditions requiring that a correction factor be used to obtain hot condition data. (100° - cold condition) Adjustments in the model to give hot condition support conditions introduce a uncertainty of 10-20% in the correlation. (Timmons, Tr. 6095.)

51. The 2/3 scale model tests did not allow measurement of a critical threshold water velocity at which vibration begins. (Timmons, Tr. 6083.)

52. Fletcher and Rajan state that the tubes are being moved by a complex mixture of both turbulence and fluid-elastic vibration. Fluid-elastic instability is present. (Fletcher Tr. 6086, Rajan Tr. .)

53. Timmons says there is no data from full scale model tests that indicate fluid-elastic vibration for counter flow program. (Timmons Tr. 6096.)

54. The object of the preheat region is to extract more heat from the primary fluid. For that reason a certain amount of turbulence is desirable.

However, a side effect of this increased turbulence is vibration of some of the tubes in that region against the support plates. This has resulted in less than acceptable tube wear on some of the tubes. (Rajan Tr. 4765-66.)

55. The problem of flow induced vibration has been at the support plate location. (McCracken Tr. 4767.) The support plate location is about a one inch thick piece of steel where the tube goes through a hole that has a nominal 20 mil clearance. When the tube vibrates, the tube within that support location becomes worn. If there is a one inch support location and thickness, a one inch spot on the tube is worn. Id.

56. It's not possible to measure drag forces on tubes in operating D2-D3 plants. (Fletcher, Tr. 6087.)

57. Premised upon its investigation, Westinghouse has recommended that Applicant make the following modifications to the Byron plant to reduce the potential for significant tube vibrations in the Byron steam generators: (1) the expansion at baffle-plate locations in the preheater region of approximately 100 tubes per steam generator and (2) the bypassing of approximately 10% of the flow from the main feedwater nozzle to the auxiliary feedwater nozzle. The expansion of tubes at baffle-plate locations will limit tube movement at the baffle-plate intersections to a resultant few thousandths of an inch clearance. The bypassing of 10% of the main feed flow to the auxiliary nozzle of the steam generator will reduce the main feed flow at the inlet to the preheater to approximately 90%. (Timmons, Test. at 22-23, Tr. 5908; Butterfield, Test. at 4, Tr. 5908.)

58. The tube expansion process is scheduled to begin in mid-July prior to start up of the Byron Station. Changes to the control circuitry of the feedwater preheater bypass valve and the installation of a feedwater

bypass line flowmeter will occur at the same time as the tube expansion program. (Butterfield Test. at 5, Tr. 5908.)

59. The tube expansion involves the insertion of tools into the tube from the primary side of the steam generator tube sheet. The tubes are then used to locate the baffle plate intersection and to expand the tube at the appropriate location. (Timmons Test. Tr. 5908 at 23.)

60. The process is called hydraulic expansion. Westinghouse has utilized hydraulic methodology for expanding steam generator tubes in the tube sheet since 1977. (Timmons, Tr. 6269.)

61. Westinghouse's determination of the levels of residual stresses in expanded tubes and conclusion that the levels of residual stresses in expanded tubes combined with the relatively low temperature in the preheater region will not significantly increase the potential for stress-corrosion cracking in the expanded location is based upon tests on earlier expansion of tubes in the tube sheet. (Id. at 24, Frank, Tr. 4701-02.)

62. Expansion of tubes at baffle plate locations will limit the tube movement at the baffle plate intersections to a few thousandths of an inch. (Timmons, Test. Tr. 5908 at 22-23.)

63. Westinghouse has also conducted "accelerated" corrosion testing to assess the effects of the reduced tube-to-tube hole clearance on the potential for denting of the expanded tubes. The results of this testing indicate that the potential for denting is not increased for tubes expanded at the baffle intersections. (Timmons Test. at 24-25 Tr. 5908.)

64. The 100 tubes identified as candidates for expansion at Byron are regarded as a bounding number. (Timmons Tr. 6038-39.) These tubes have been determined to be the most susceptible to tube vibration. (Timmons, Tr. 6209; Rajan Tr. 4767-68.)

65. The precise location and number of tubes to be expanded is not yet known. (Timmons, Tr.6055, 6240, 6306.)

66. Westinghouse has established a vibration level at or below which tube degradation is not expected to progress through 40% of the tube wall. (Timmons, TR. 6198.)

67. Based on it's test date Westinghouse does not expect that a 90-10 flow split of approximately 100 expanded tubes in each steam generator will reach the 40% tube wall degradation level requiring plugging as a result of the flow-induced vibration over the 40-year life of the plant. (Timmons Tr. at 6198-99, 6202, 6265.)

68. Neither does it expect non-expanded tubes at Byron to experience 40% wear through the tube wall over the 40-year life of the plant. (Id. at 6198.)

69. Timmons admits that a small number of expanded tubes may have to be plugged over lifetime of plant. (Timmons Tr. 5999.)

70. Timmons says some of his colleagues at Westingnouse may have specific tubes picked out which may have to be plugged due to vibration wear. (Timmons Tr. 6000-1.)

71. Timmons changes testimony to remark that he now believes no tubes will have to be plugged at Byron over its life. (Tr. pages 6000-1.) He said a small fraction would have to be plugged. He says that he has received other information that indicates expanded tubes and bypassing feedwater flow is such that vibration would remain below a threshold level that would lead to tube plugging. (Timmons, TR. 6264.)

72. Timmons didn't know how many more hours it would take for the tube with 6% degradation removed from Krsko in May to reach 40% degradation given the same power level ranges for the period January - May of 1982. (Timmons TR. 5980.)

73. Westinghouse intends to install accelerometers at the first plant at which the proposed modification is to be implemented in order to confirm that the vibrations seen in that plant are representative of those seen in the test models and at Krsko. (Timmons, Tr. 6058.)

74. More accelerometers have been put in Krsko to further determine the boundaries of tube vibration. (Timmons, TR. 5953.)

75. Timmon's opinion it will not be necessary to install accelerometers at Byron because the data gathered from Krsko and test models has already done the necessary correlating of vibration to tube wear. (Timmons Tr. 5940, 5941.)

76. Comanche Peak Unit 1 will be the first operational plant instrumented not Byron. (Timmons, Tr. 6058.)

77. Timmons is wrong on Comanche Peak fuel load date. NRC staff believes Byron and Comanche Peak will load December of 1983. (Timmons Tr. 6065.)

78. Timmons states that instead of removing expanded tube at Krsko in June 1983, it might be better to leave it as is and see what effect expansion of 100 other tubes around it has on the vibration of that tube. (Timmons Tr. 6062.)

79. 12 tubes are now instrumented at Krsko. (Timmons, Tr. 6064.)

80. Timmons states that Byron would conduct eddy current testing to verify that the tubes were not wearing and that would constitute part of the post modification testing program. (Timmons, Tr. 6058.)

81. Special inspectors were done over the past 6-9 months at McGuire on the tubes in the pre-heater area. (Tr. 4678.)

82. An enhanced inspection program like that at McGuire will be required of the staff for tubes expanded at the support plates(baffle plates). (Tr. 4679.)

83. In order to operate at a 70/30 split, the feedwater bypass system at Byron would require a structural modification. (Butterfield, Tr. 6204)

84. The fact that no structural modification would be required under a 90/10 flow split at Byron had some input into Westinghouse's choice of it for a final modification for Byron. (Timmons, Tr. 6224)

85. Westinghouse came to the conclusion that in order to have a modification that was sufficent to reduce the vibration to a lower level a combination of tube expansion and at least 10% bypass would be needed for plants that had slow rates for four-loop plants and at least 20% bypass would be needed for two-loop and three-loop plants with D-4, D-5 steam generators. (Timmons, Tr. 6225)

86. For a 80/20 split, you have to increase the resistance in the main feedline by installing either a different valve or an orifice or something like that. Purchase and installation of an 18-inch orifice costs hundreds of thousands of dollars. You also have to change the valves and decrease the flow resistance in the feed bypass line, depending on what system you install, valves used, and line flow resistance. A 70/30 split would require new piping, installation of a flow restricter or flow resistance in the main feedline. The costs of either modification would range from something in the hundreds of thousands of dollars to possibly a million dollars or more. (Timmons, Tr. 6227)

87. The test simulation of various tube support heights and support plate hole did not occur in a field setup, but was a computer analytical model utilizing a stick or line to represent the tube and a circle gap element to represent the plate hole. (Timmons, Tr. 6240)

88. When an accelerometer is installed inside a steam generator tube, the tube is plugged at the front primary face of the tube sheet and it is opened at the tip of the tube where the leads of the accelerometer come out and exit through the steam generator. There is no primary water or flow on the inside of the tube where the accelerometer is located and no pressure differential between the inside and outside of the tube, versus a 1250 pound pressure differential

across the wall for a non-instrumented tube. Initial fluid testing by Westinghouse indicates vibrational characteristics between the two types of tubes differ less than one percent. (Timmons, Tr. 6252-6253)

215. In place of tube expansion, Westinghouse considered at one point the insertion of either solid rods or cables or something inside potential high vibration tubes, but did not proceed with it because such devices would not provide a significant amount of damping, or neccessarily lead to reduction in the vibrations of the tube, though it would stabilize the tubes so that they could not sever and become loose parts within the steam generator. (Timmons, Tr. 6259)

216. Furthermore it would take a significant amount of resources to design and manufacture a sufficient number of these devices to be able to apply them in the plants in any short period of time. (Timmons, Tr. 6259-6260)

217. A 70/30 feedwater split at Krsko would translate into approximately a 75/25 split at Byron but such a reduction in main nozzle feed flow was not thought neccessary at Byron if a 90/10 split was used in conjunction with 100 expanded tubes. (Timmons, Tr. 6262)

218. Krsko is presently operating at 100% power on a 70/30 main feedwater split with no expanded tubes. The 70/30 non-expanded split at Krsko is not considered by Westinghouse to be a short-term safety concern, in terms of some tube wear, but rather a long-term concern. Krsko will undergo further modification and expand 100 tubes also, and operate on a 80/20 split. (Timmons, Tr. 6263-6264)

219. If Byron is the first plant to experiment with the Westinghouse modifications, Westinghouse intends to instrument it. (Timmons, Tr. 6304,6305)

220. The latest information identified in page 5 of Rajan's prefiled testimony consisted of the general identification of the tubes that will be expanded, their matter of expansion and supporting data from model tests which justified the selection of the tubes. This information was presented to the NRC and Rajan

at a meeting one week or ten days prior. (Rajan, Tr. 6310)

89. With the exception of sponsoring research efforts at various laboratories; in this case at Argonne National Lab, no agency (NRC sponsor or) other than Westinghouse has reviewed or conducted testing on flow-induced tube vibration. Furthermore, Argonne, while familiar with data collection techniques and plant sites has not conducted tests such as Westinghouse's, except for single tube models which are more routine. Argonne has merely reviewed the data accumulated by Westinghouse from operating plants and tests with respect to this recent tube vibration issue. (Rajan, Tr. 6329-6331)

90. Staff has not recieved a final report on the proposed modifications from Argonne at this time, and will not recieve the evaluation until a week or two of the Westinghouse report. (Rajan, Tr. 6332)

91. Argonne's review of the tube vibration issue is based upon viewgraphs, and a formal report recieved from Westinghouse on the D2, D3 modification, including the analytical methods, operating plant data and their evaluation package.

Loose Parts Monitoring System

92. Tube rupture due to foreign objects can cause a tube rupture. Two such recent incidents have occurred at Prairie Island Unit 1 in 1979 and at Ginna in 1982. (Fletcher, Test. 14 at Tr. 5908)

93. The Prairie Island rupture was due to a coil spring which remained in the steam generator following an earlier outage for steam generator maintenance. (Id.)

94. The Ginna rupture was also due to the presence of a foreign object which impacted against and severed a previously plugged tube. The severed tube subsequently wore against an unplugged tube providing a long wear scar which ultimately led to tube leakage. (Id.)

95. The potential for damaging tubes as a result of foreign objects and loose parts being present in steam generators can be minimized by appropriate surveillance. Examples of available surveillance methods include visual inspections with the aid of fiber optics and/or radio camera devices, and loose parts (acoustic) monitoring of the steam generator during operation. (Frank Test., ff. Tr. 4473, at 2-3)

96. Visual inspections on the secondary side of the steam generator of plugged tubes are not normally performed. (Patel, Tr. 4146, 4147)

97. Applicant intends further to conduct periodic visual inspections of the secondary side of the steam generators during refueling and maintenance outages. (Tr. 4257, 4424 (Blomgren)).

98. Plugged tubes cannot be tested for loose parts potential because no eddy current test exists for plugged tubes. (Marsh, Tr. pg. 4495, 4496)

99. Page IV.7-1 of the S.A.I. Report, Section 7.1.1, indicates "PWR licensees shall be required to develop criteria and procedures for stabilization of degraded tubes that may be subjected to progressive degradation mechanisms having the potential to cause severance of the tube and consequently to damage adjacent tubes."

100. Byron is being required to implement Regulatory Guide 1.133 which provides in part for a loose parts monitoring system. (Blomgren Test., ff. Tr. 4126, at 14)

101. This system includes two sensors on the secondary side of each steam generator. These sensors listen for noise generated by loose parts. (Blomgren Test., ff. Tr. 4126, at 14; Tr. 4256, 4430 (Blomgren); Frank Test., ff. Tr. 4473, at 8)

102. Materials and tools used in the steam generators during maintenance and inspection will be controlled through written tool and material inventory control procedures. The control procedures will require an inventory and accounting of all tools and materials entering the secondary side of the steam generators prior to return to operation. In addition, hold points will be required in maintenance procedures for cleanliness operations. (Id. at 12-13)

103. These procedures are still in draft form and may or may not be in place before fuel load. (Blomgren, Tr. 4256, 4257)

104. No one of staff panel was familiar with LPMS at Byron (Tr. pg. 4499)

105. McCracken clains Byron SER describes only a primary system LPMS. (McCracken, Tr. 4509) But on next page Frank quotes a sentence that says "There will be two accelerometers on the lower plenum of each steam generator." (Frank, Tr. pg. 4510)

106. Mr. Blomgren has looked at the loose parts monitoring system at Byron and its specifications and feels the LPMS of Byron should be able to meet the requirement of Reg. Guide 1.133 that a 1.25 lb. metallic part impacting with a kinetic energy of 0.5 ft./lb. be detected if it is within 3 feet of the detector. (Blomgren Test., Tr. 4166, pg. 16)

107. Mr. Blomgren is not "completely familiar with all the techniques that are involved with detecting loose parts and evaluating the size and position of those parts." (Blomgren, Tr. 4166)

108. The sensitivity of the loose parts monitoring system depends on a number of factors and involves a pretty complicated estimate to determine the sensitivity of a given sensor. (Blomgren, Tr. 4164)

109. The ultimate sensitivity of the loose parts monitoring system will not be determined until some time during the early stages of the start-up of the plant. (Blomgren, Tr. 4166, 4167)

110. To say specifically that the Byron system will be able to do this or that is really going to be based only on the results of the start-up tests. (Blomgren, Tr. 4167)

111. Edison has concluded that due to the LPMS and water chemistry guidelines a tube stabilization system will not be needed at Byron. (Blomgren, Tr. 4262)

112. It is Bridenbaugh's understanding that the LPMS is not an active system, is there for periodic monitoring, and is not required in technical specifications, i.e. is not a limiting condition for operation. He believes it should be. (Bridenbaugh, Tr. 6502)

113. Additional generic surveillance requirements are undergoing Staff development and review. (Frank Test., Tr. 4473)

114. The LPMS is expected to reduce the potential for the types of problems which have been experienced to date. However, some degree of degradation is likely to occur at Byron during its lifetime. Given the potential for degradation, surveillance requirements are essential to ensure adequate tube integrity is maintained against rupture and excessive leakage during the full range of normal operating and postulated accident conditions. (Frank Test., ff. Tr. 4473, at 4)

115. Commonwealth Edison also will monitor the Byron reactor systems for primary to secondary leakage. (Patel, Applicant Prepared Testimony at 11-13, ff. Tr. 4126) To stem degraded tubes from occurring to the point where rupture is possible, licensees are required to shut down and repair steam generator tubes should the primary to secondary leakage exceed a maximum allowed by technical specification. (Rajan, Frank, NRC Staff Prepared Testimony at 3, 7, ff. Tr. 4473)

116. The maximum permissible leak rate is established consistent with the "leak-before-break" principle set forth in the Technical Specifications. Inconel 600 is used in steam generator tubing, a material in which degradation in the form of cracking penetrates through the wall causing a small primary to secondary leak long before the crack reaches a linear length called the "critical length," where tube rupture can occur. (Patel, Applicant Prepared Testimony at 11-12, ff. Tr. 4126)

117. The maximum permissible leak rate during normal operation at Byron has been established through leak rate and burst pressure tests at the Standard Technical Specification limit of 0.35 gpm per steam generator. (Id. at 12, Marsh, Tr. 2735) This corresponds to a maximum allowable crack length of 0.43 inch. (Patel, Applicant Prepared Testimony at 12, ff. Tr. 4126)

118. The critical crack length corresponding to the maximum accident condition pressure during a postulated Main Feedwater Line Break (MFLB) or Main Steam Line Break (MSLB) was conservatively determined to be 0.51 inch using the results of the burst pressure tests. (Id. at 12-13)

119. Thus, shutdown for remedial action should take place before the critical crack or calculated burst point of 0.51 inch is reached. (Id. at 13)

120. Partially degraded tubes are acceptable for continued service as long as it is assured, through inservice inspections (utilizing eddy current techniques) and leakage monitoring, that degraded tubes meet the applicable tube wall and associated strength requirements to safely withstand all operating and design basis accident condition loads. (Patel, Applicant Prepared Testimony, at 6, ff. Tr. 4126)

121. Section VI of the ASME Boiler and Pressure Vessel Code (Code) provides guidelines for establishing the "limiting safe conditions" of tube degradation beyond which defective tubes must be repaired or removed from service. (Patel, Applicant Prepared Testimony at 6, 10, ff. Tr. 4126) The limiting safe condition takes into account (1) the minimum tube wall thickness needed in order to sustain the imposed normal operating and postulated design basis accident condition tube loads; (2) maximum (Technical Specification) permissible leak rate during normal operation to preclude a tube rupture during a postulated main steam line break accident and (3) allowance for continued degradation between inspections and eddy current measurement uncertainties. (Id. at 7)

122. Plugging margins established in accordance with the requirements ensure that, at the end of an operating period, a degraded tube with loss of wall or a leak (1) will not undergo progressive yield (permanent deformation

during operation), (2) will not burst or rupture during either normal operating or the governing design basis accidents, and (3) will meet, under the postulated accident condition loadings, the applicable stress limits specified in Appendix F of Section III of the Code. (Id. at 10)

123. Applicant follows Section XI of the Code in lieu of the plant-specific program described in NRC Regulatory Guide 1.121. The amount of tube wall degradation above which the tube shall not continue in service, the tube plugging criterion, established by Section XI of the Code, paragraph IWB-3521.1, is a depth of outside wall penetration not to exceed 40% of the wall thickness for tubing from SB 163 material when the mean tube radius to wall thickness ratio is less than 8.70. (Id. at 10-11)

124. ASME calculations conclude that 50% of tube wall thickness can still meet all applicable stress and strength requirements. (Id. at 14; Patel, Tr. 4133, 4372, 4433)

125. The 40% figure allows for a 10% uncertainty factor in both eddy current measurement and corrosion allowance for continued plant operation until the next inspection. (emphasis added) (Patel, Applicant Prepared Testimony at 14-15, ff. Tr. 4126; Malinowski, Tr. 4433)

126. Based on Regulatory Guide 1.121, it could be concluded that the thickness necessary for a tube to bear accidents or normal operation generally approaches 40%, i.e., 60% degradation, thereby building in an extra 10% conservatism. (emphasis added) (Malinowski, Tr. 4433-34)

127. Thus from Regulatory Guides one could conclude that significant tube degradation will be detected well within the sensitivity limits of eddy current testing, 20% to 40% tube wall loss depending upon the type of tube degradation. (See Fact

Pre-service and In-service Inspections

128. Commonwealth Edison performed a baseline examination of the tubes in the steam generators at Byron. (Paillaman Test. at 4, Tr. 4818)

129. The purpose of performing the pre-service inspections is to establish a baseline against which subsequent in-service inspections can be compared. (Paillaman Test. at 4, Tr. 4818; Blomgren Test. at 11, Tr. 4126)

130. A pre-service inspection was conducted of 100% of the tubes using multi-frequency eddy current examination. (Paillaman Test., Tr. 4818, at 5) The eddy current probe is designed to measure any severe departures from a nominal condition. (Tr. 4393-94, Malinowski)

131. The data was reported in accordance with Article IV-6000 of ASME Section XI, which requires the reporting of tube wall penetrations in excess of 20% of the tube wall thickness and tube wall dents. (Id. at 6)

132. Based upon the inspection, a baseline was established for Unit 1. The inspection revealed that two tubes were partially blocked. The cause of blockage could not be determined. (Paillaman, Tr. 4821, 4826)

133. Based on a Westinghouse recommendation, the two tubes were plugged. (Id.)

134. Some processing-induced denting was discovered. The dents or "dings" were not considered sufficiently significant to warrant tube plugging as no tube locations were found with 20% or greater wall loss. Most of the denting was located four or 5 inches away from the tubesheet. That is, in the preheater beltline. (Id. at 8; Paillaman, Malinowski, Tr. 4825-26)

135. Dr. Paul of Ebasco Services, Inc., was originally scheduled to testify about the pre-service inspection program but Applicant presented Mr. Rodolfo Paillaman instead. (Tr. 4812)

136. Paillaman's testimony was a revision of Dr. Paul's prefiled testimony, including a revision of answer 8, page 8. (Paillaman, Tr. 4813-4814)

137. Paillaman scratched out "especially in Row 1 of Steam generator No. 1," from "A number of tubes, especially in Row 1 of Steam generator No. 1, were found to have processing-induced dents," in Paul's original testimony. (Paillaman, 4813-4815)

138. Paillaman did not agree with the sentence as written by Paul which would highlight defects found in Row 1 tubes which is a suspected area for service-induced dents and cracking at the apex of U-shaped tubes as a secondary effect of denting. (Paillaman, Tr. 4815, 4823; Malinowski, Tr. 4824)

139. There were from 2 to 3 dents on selected tubes for a total of 600 dents in Steam generator No. 1, 500 for Steam generator No. 2, 450 for Steam generator No. 3, and 550 for Steam generator No. 4. (Paillaman, Tr. 4824)

140. Steam generator No. 4 was found to have a large number (124) of tubes with indications of permeability; a localized area of magnetic material or impurities in the Inconel which require a different technique for an examination to verify integrity of the tubes. (Paillaman, Tr. 4826, 4827, 4828)

141. The condition of the Byron steam generators will be periodically monitored through an inspection program. Inspections will be performed according to the provisions of the Byron Technical Specifications and according to NRC Regulatory Guide 1.83. (Blomgren, Tr. 4282-4282 A; Blomgren, Applicant Prepared Testimony at 11, ff. Tr. 4126; Frank, NRC Staff Prepared Testimony at 4, ff. Tr. 4473)

142. The results of these periodic inspections will be compared to the 100% pre-service baseline examination. This comparison will provide a periodic evaluation of the steam generator tubing condition to allow time for the initiation of appropriate measures for steam generator maintenance prior to any occurrence of primary to secondary leakage. (Blomgren, Applicant Prepared Testimony at 11, ff. Tr. 4126)

143. NRC Regulatory Guide 1.83 requires that in-service inspections be performed every 12 to 24 months. (NRC Regulatory Guide 1.83, Section C6(b).) In cases where the degradation processes have been highly active, the Staff has required that the inspections be performed at more frequent intervals, consistent with the rate at which degradation is occurring. (Frank, NRC Staff Prepared Testimony at 4-5, ff. Tr. 4473)

144. Technical Specifications require sampling (at minimum) 3% of all the tubes in the plant in the first in-service inspection. Future inspections may be expanded to cover 100% of the tubes in circumstances where either (i) greater than 10% of the tubes inspected have eddy current indications greater than 20%, or (ii) greater than 10% of the tubes inspected exceed the plugging criterion. (Malinowski Test. at 7, Tr. 4126; Frank Test., Tr 4473 at 4-5)

145. The total number of tubes to be inspected during an in-service inspection will range between 3% and 100% of the total number of steam generator tubes. (Frank Test., Tr. 4473 at 5)

146. At Byron subsequent inspections will relate to all unplugged tubes previously identified to have eddy current indications greater than 20% as well as the 3% total sample provided by the Technical Specifications. (Id. at 7-8)

147. Eddy current testing is the primary inspection technique and it is usually performed using an instrument that impresses four different test frequencies on the coils simultaneously. The frequencies are selected on the basis of providing definitive information on tube degradation, support plates and external deposits. Because the responses for external discontinuities vary according to the test frequency, it is possible by linear combinations of the responses at different frequencies to reduce unwanted signals from a composite response. (Id. at 12; Frank, Tr. 4726) Although Intervenor's witness questioned the amount of experience with eddy current testing, he acknowledged that multifrequency testing is a significant improvement over earlier methods and may be adequate, depending on type of tube degradation experienced. (emphasis added) (Bridenbaugh, Tr. 6461)

148. The sensitivity of eddy current testing to tube wall degradation varies depending upon the size, shape and nature of the degradation. Eddy current testing will reliably detect the various types of tube degradation at the following sensitivity levels: tube wall thinning at 20% depth of the tube wall (Id. at 16); pitting at 20% tube wall depth (Id. at 17); tube wall cracking at 40% tube wall depth (Id. at 18-20); intergranular attack at 40% tube wall depth (Id. at 21); tube wear at 20% of tube wall depth (Id. at 21-22). Denting, a form of tube deformation, can be detected by eddy current testing (Id. at 13-14). Eddy current development now in progress in the industry is expected to further improve detection limits and characterization of possible tube degradation. (Id. at 22; Blomgren, Applicant Prepared Testimony at 12, ff. Tr. 4126)

149. The eddy current method should enable significant tube wall penetration at or below the plugging limit of 40% to be detected. (Blomgren Test. at 12, Tr. 4126)

150. If a significant rate of tube degradation is determined as a result of an in-service inspection, measures are available to reduce the probability that tube leakage will occur before the next scheduled inspection. These measures include (water chemistry) alterations such as temperature changes, water lancing, flushing and chemical cleaning to try to loosen and remove degradation-causing impurities or deposits; foreshortening and reducing the interval between inspections or plugging more tubes. (emphasis added) (Id. at 8)

Water Chemistry

151. Operating plant experience has shown the need for rigorous control of the secondary side water chemistry environment, including the condensate and feedwater systems. (Wootten Test. at 7-9, Tr. 4126; Fletcher Test. at 7-8, Tr. 5908)

152. Because of the extensive laboratory work that has been performed in evaluating the mechanisms of stress corrosion cracking, thinning and denting of the steam generator tubes, it is clear that impurities admitted to the steam cycle which ultimately may reside in the steam generator, must be limited. (Fletcher Test., ff. Tr. 5908, at 8-9)

153. Impurities such as air, which contains oxygen, condenser cooling water such as fresh water sources that contain excess alkalinity, makeup water impurities and the like, must be excluded to the extent possible. It has also been demonstrated that copper bearing alloys in the feed train can participate in corrosion reaction when transported to the steam generators. (Fletcher Test., ff. Tr. 5908, at 9)

154. Accordingly, the Applicant is implementing an AVT water chemistry program on the secondary side of the reactor systems at the Byron Station. (Blomgren, Applicant Prepared Testimony at 3-11, ff. Tr. 4126; Fletcher Test. at 11, ff. Tr. 5908)

155. AVT chemistry control is based on a philosophy of minimum contaminant ingress through the practice of good initial design and material selection of condensers, feedwater heaters, makeup water systems and other components. (Fletcher Test., ff. Tr. 5908, at 7-8)

156. AVT control is maintained by appropriate inspection and maintenance practices and operator actions during plant operation. Adherence to AVT guidelines enhances the long term integrity of the steam cycle, by minimizing the corrosion of condenser and feedwater heater materials, the steam generator and the turbine. This in turn minimizes the formation of corrosion products which are delivered to the steam system. (Wooten, Test. at 9-10, Tr. 4126.)

157. AVT involves the addition of volatile chemicals as control agents. These agents do not concentrate in the steam generator but are removed via the steam to the remainder of the secondary system. Generally two chemicals are added, a volatile amine (usually ammonium hydroxide) for pH control of the feedwater and an oxygen scavenger (hydrazine). Hydrazine scavenges oxygen producing innocuous byproducts such as nitrogen and water. As the hydrazine moves through the feedwater system and is subjected to higher temperatures, any unreacted hydrazine can decompose to form volatile compounds such as ammonia, nitrogen and hydrogen. The addition of ammonium hydroxide for pH control is adjusted to compensate for that produced from the excess hydrazine thermal decompsition. (Wootten, Test. at 9-10, Tr. 4126.)

158. Applicant's AVT water chemistry program is based on Westinghouse and EPRI guidelines (Applicant Exhibit 17.) (Blomgren Test. at 3-11, Tr. 4126.)

159. In order to reinforce the need for vigorous chemistry control, EPRI has issued AVT guidelines as a model to be reviewed by the industry. (Fletcher Test. Tr. 5408, at 8.)

160. The Westinghouse guidelines, introduced in 1977 and modified subsequently from time to time, recommend that (1) the guideline chemistry conditions should be achieved prior to unit loading and maintained during power changes; (2) any source of contamination should be identified, the source corrected and no operation allowed with locatable contaminant ingress;

(3) dissolved oxygen at the condensate pump discharge should be less than 10 ppb to minimize the inventory of corrosion product transported to the steam generator; (4) continuous monitoring of the chemistry of the steam generator blowdown should be performed; measured values should be compared to theoretical values in order to identify whether or not excess alkalinity or acidity is present; (5) copper bearing alloys should be eliminated from the secondary system to permit greater flexibility and optimization in chemistry control; (6) main condenser integrity should be upgraded to minimize the ingress of impurities in the condensate in order to improve the reliability of the steam generators and turbine; and (7) if a full-flow condensate polishing system is installed, it must be carefully controlled and properly operated in order to optimize the quality of the treated condensate. (Wootton Test. 14-16 Tr. 4126.)

161. The so-called EPRI Guidelines were developed under the aegis of the Steam Generator Owner's Group (SGOG). These guidelines incorporate more restrictive water chemistry controls than the Westinghouse guidelines and include a staged corrective action plan. In addition to the more restrictive water chemistry controls, the EPRI Guidelines include recommendations for data management, surveillance, and analytical methods. The EPRI Guidelines include a recommedation that specific management responsibilities regarding secondary water chemistry control <u>be assigned from the plant chemist to senior corporate management</u>. (Blomgren Test. at 9, 4126; Applicant Ex. 17.)

162. In addition to the Westinghouse Guidelines noted above, the Byron Station Chemistry Monitoring Program incorporates the following elements from the EPRI Guidelines: (1) more restrictive EPRI water chemical controls coupled with a corrective action plan to require prompt station response to a chemistry excursion before unit shut-down is required; (2) a staged

corrective action plan based upon the level and duration of contaminant ingress, requiring specific corrective actions, including staged reductions in power; (3) a data management and surveillance program providing for prompt identification of negative trends or inconsistencies in chemical control data; (4) an analytical program to supplement and verify the continuous on-line chemistry monitoring system data. Although not specifically included in the Byron Chemistry Monitoring Program, the statement of management responsibilities recommended in the EPRI Guidelines is being addressed in a Commonwealth Edison corporate PWR Secondary Water Chemistry Control Program. (Id. at 10-11.)

163. There have been limited occurrences of corrosion mechanisms in plants where AVT has been the exclusive water chemistry control. One plant experienced pitting of the Inconel tubing which is believed to be due to an acidic chloride condition involving copper and chloride ions. There have been a small number of stress-corrosion cracking incidents. (Wootten, Test. at 14, Tr. 4126.)

164. The rupture at Point Beach was caused by secondary side intergranular stress corrosion cracking which occurred as a consequence of reactions between condenser inleakage impurities and residual phosphates. ( ) (Tr.)

165. Byron will use all volatile chemistry treatment; consequently, the chemical reactions which caused the Point Beach rupture should not occur at Byron. Id. Since the industry conversion to AVT in 1974, no plant which has started up on AVT has detected secondary side initiated stress corrosion cracking, Id.

166. The rupture at Surry was initiated from the primary side of the tube and caused by excessive tube stress. (McCracken Test. Tr. 4473 at 5,

Tr. 4779-80.) The excessive tube stress resulted from extensive tube denting which first froze the tube in place and then physically moved the tube support plates, resulting in a significant deformation of the tube and resultant high stress. (McCracken Test. Tr. 4473 at 5.)

167. Conway used illustration of flow slots on tube support plate to demonstrate how density caused hourglassing of tube flow slots in tube support plates thus pinching the support plates and in turn pinching the tubes; thus compressive stresses induced by pinched tubes caused tensile stresses at the U-bend (and hrs,) because on the D-5, the widest spacing between tube support plates which is functionally acceptable was selected and the holes in the flow distribution baffle plates and in the top tube support plate were modified to minimize the tube stresses further, it would be less suseptible to this occuring than the D-4 unit. (Conway Test. at 14-15, Tr. 4126, 4353-4360.)

168. The hydraulic tube expansion technique for expanding tubes at the tubesheet was used only for Unit 2 Model D-5. The tube expansion technique used for unit one was mechanical dilation techniques with greater inherent residual stresses. (Tr. 4328-4329.)

169. A form of tube thining has also been observed at lower tube support plate elevations around the periphery of the bundle at two all-Avt plants. (Wootten, Test. at 14, Tr. 4126.)

170. Plants that have only operated on Avt have experienced some denting. (Wootten, Test. at 13-14, Tr. 4126.)

171. Denting is a localized radial reduction in the diameter of steam generator tubes, resulting from corrosion of the carbon steel tube support plates in the tube-tube support plate annulus, as in the D-4 Model. (Wootten Test at 10-11, Tr. 4126; Malinowski Test. at 21, Tr. 4126.)

172. Another source of denting identified through field tests is the

condenser in-leakage of contaminants from the tertiary water system such as copper, oxygen, and chloride ions. (Wootten, Test. at 11-12, Tr. 4126.)

173. The 1977 Westinghouse AVT Guidelines advocated rigorous control of the condensate and feedwater chemistries during both shutdowns and power operation to minimize secondary system corrosion and transport of the corrosion products into the steam generators. (Wootten Test. at 13,)

174. Concentrations of chloride in the levels of thousands of parts per million can build up in the tube support crevice even though the bulk steam generator solution is only at the part per billion level. (Wootten Tr. 4176.)

175. Chloride levels on the order of thousands of parts per million (ppm) have been seen in the corrosion deposits in the tube support plate crevice. (Id.)

176. No method has been developed for determining the concentration of corrodants contained in the tube support plates annulus where denting is known to occur. A sample of the chemical solution contained in the tube support plate crevice has never been taken. Neither is there any empirical evidence on the concentration of corrodants at the tube support plate coeurces or the minimun concentration of corrodants necessary at the crevice of corrosion to occur. Thus, in operation, it would not be possible to determine what concentration value would indicate excessive corrosion, nor the corrosion product volume and rate which would lead to eventual tube leaks between inservice inspections. (Blomgren, Tr. 4213-4214; Wootten, Tr. 4177, 4176.)

177. The guidelines themselves don't indicate format for reporting violations, that is left to the utility. Violations or failures to adhere

to the water chemistry guidelines to be followed at Byron will be reported only on an annual basis to the Nuclear Division Vice President. (Blomgren, Tr. 4213.) There is no requirement anywhere to report violations of the water chemistry guidelines to the NRC office of Inspection and Enforcement. (Id. 4213-14.)

178. Status has changed on 44 steam generator procedures applicant is developing and identified in November 1982. Edison will complete all procedures before Byron fuel load, including secondary chemistry program descriptions and chemistry procedures. (Tr. 6514, 6515.)

179. When asked why he recommends that Byron operating chemistry procedures should be reviewed by an independent body, Bridenbaugh says that NRC's ITE branch and resident inspector can not conduct an independent review. Their review is merely to assure that proper procedures are in place and is limited to the assurance that the procedure is identified and followed and complied with. (Bridenbaugh, Tr. 6462, 6466.)

180. This review wasn't done when EPRI and SGOG drafted guidelines. Bridenbaugh says NO! He says they are just guidelines. He's talking about a review of plant specific chemistry monitoring equipment and procedures to ensure the guidelines are indeed being implemented to greatest degree possible. An operating license shouldn't be issued until this is done. (Bridenbaugh Tr. 6465.)

Tube rupture events.

181. Mr. Bridenbaugh testified that there is an increased probability that accidents will be initiated by tube failures during normal operation and an increased likelihood that accidents not now considered in the safety analysis may occur as a result of the steam generator tubes degradation after some period of operation. The accident sequence could involve single

or multiple tube failures occuring in conjunction with other accident sequences. (Bridenbaugh Test. Tr. 6406, at 5.)

182. Mr. Bridenbaugh, acknowledged that he performed no independent analysis or calculations to quantify the increased probability of steam generator tube failures (Tr. 6475.) nor had he performed any independent calculations or analyses to ascertain either the probability or radiological consequences of multiple steam generator tube ruptures and concurrent accidents. (Bridenbaugh, Tr. 6476.)

183. Mr. Fletcher assimilated the conclusions provided by the Applicant's expert witnesses testifying with respect to their specific disciplines and reached an overall assessment as to steam generator tube integrity at the Byron Station. Based upon the design, water chemistry, detection and remedial measures undertaken by Applicant, Mr. Fletcher concluded that steam generator tube degradation at the Byron Station should not be a safety concern and that tube rupture should not occur, even under conditions of Main Steam Line Break (MSLB) or Loss of Coolant Accidents (LOCA's). (Fletcher, Test. at 18, Tr. 5908.)

184. A Byron specific PRA which considers tube ruptures and LOCA has not been done. (Tr. 6124.)

185. The effect of the steam generator tube rupture upon a large MSLB, MFLB and LOCA have been considered by the Staff. (Marsh Test. Tr. 4473 at 4.)

186. The NRC Staff's multiple steam generator tube rupture analysis has not been published and is still under staff review. (Tr. 4484.)

187. The consequences of a large MSLB inside containment could be adversely affected by such an event. However, calculations have shown that containment integrity is not effected, the core remained covered and cooled due to the addition of emergency core cooling, and there is ample water supply available for long term cooling. Id.

188. Calculations have been performed to evaluate the systems performance, offsite consequences and required operator actions assuming a steam generator tube rupture concurrent with an MSLB outside containment. These studies evaluate the effects of a main steam line break combined with one or five ruptured steam generator tubes in a small break LOCA.

189. A series of LOCA experiments with varying degrees of simulated tube failures performed in the semi-scale facility at the Idaho National Engineering Laboratory several years ago confirmed this general behavior. (Marsh Test. Tr. 4473, at 6.) These experiments did not show the same degree of degraded core cooling as the computer analysis did for the worst cases. In fact, the experiments did not indicate that any core damage would occur. Id.

190. The overall consequences of a large MFLB with simultaneous steam generator tube rupture were bounded by the combined MSLB and tube rupture inside or outside containment. (Marsh Test. Tr. 4473, at 6, 4784-85.)

191. The Staff does not postulate one of these events combined with the steam generator tube rupture as a design basis event as it does not believe they pose an undue risk to public health and safety. (Marsh, Frank, Rajan Test. Tr. 4473, 6-8.)

192. The MSLB, MFLB and cold and large cold leg break LOCA accidents are extremely low probability events on the order of 10^{-5} to 10^{-6} per reactor year. (Marsh Test. Tr. 4473 at 7, Tr. 4723.)

193. The steam generator tube rupture event, while not as infrequent as the LOCA, MSLB or MFLB accidents, is also an infrequent event on the order of 10^{-2} or 10^{-3} per reactor year. (Marsh Test. Tr. 4473, at 7; Tr. 4724.) In the opinion of the Staff, taken independently, or together, the likelihood of a tube rupture concurrent with a LOCA, MFLB or MSLB is extremely low.

(Marsh Test. Tr. 4473, at 7.)

194. The results of these analyses indicate that primary coolant shrinkage, caused by overcooling, and the simultaneous loss of primary coolant, can be compensated by the high pressure emergency core cooling system. The core remains covered, and the primary coolant remains cool, except in the vessel upperhead. The calculations and results are described in NUREG-0937. Id.

195. As part of the technical resolution of the steam generator tube integrity unresolved safety issue, the Staff assessed the consequences of single and multiple tube breaks (in a single steam generator) concurrent with a large main steam line break or large cold leg break LOCA. (Marsh Test. Tr. 4473 at 5.)

196. One of the main purposes of this effort is to develop a statistically based inservice inspection program that affords a high degree of assurance that if a large MSLB or LOCA occurred concurrent with ruptured steam generator tubes in the effected steam generator, the offsite dose and fuel temperatures are acceptable. Id.

197. The consequences of a large, cold leg LOCA could be adversely affected by the flow of steam generator fluid into the primary loop through the broken steam generator tubes. Several computer studies performed over the years indicated the following: (1) rupture of a few tubes during a LOCA would have very little effect, (2) if a large number of tubes ruptured, the additional fluid flow into the reactor vessel during a large break would actually aid in cooling the core, and (3) an optimum number of tubes over a limited range (about 12) could have a detrimental effect. However, it is not expected to lead to a core meltdown. Id.

198. The Applicant performed an analysis whereby it predicted that tube

rupture events in combination with accidents are predicted to result in severe core damage at frequencies of 10^{-7} per year for the Byron Station. (HItchler Test. Tr. 5908 At 8, Tr. 6231.) By this calculation, a single tube rupture would occur about once every 33 years at Byron. (Hitchler Tr. 6235)

199. Goldberg asks Bridenbaugh if the Byron FSAR analysis postulates failure of one tube and only 1 gpm leakage, and whether he believes that? Bridenbaugh says no - he believes it could be as high as 760 gpm since that was what was seen from the single-tube failure at Ginna. (Bridenbaugh Tr. 6487-6488.)

200. Bridenbaugh explains how multiple tube failures could occur, with a Ginna precursor as initiator. (Bridenbaugh Tr. 6457-6458.)

201. As part of the Staff's ongoing evaluation of the four domestic steam generator tube ruptures and steam generator tube degradation in general, a number of specific requirements are being considered. (Marsh, Frank, Test. Tr. 4473 at 7.)

202. Twelve potential requirements are presently undergoing cost-benefit assessment by the Staff and it consultant. Id. The consultant cost-benefit assessment is contained in a final draft report, the S.A.I. report, entitled "Value Impact Analysis of Recommendations Concerning Steam Generator Tube Degradation and Rupture Events" (marked for identification as Intervenors' Exhibit 9 at Tr. 4443.) These items are under consideration as potential Staff requirements. (Marsh Tr. 4573.) The Staff has continued to evaluate these recommendations since the issuance of the consultant report, and has modified, altered and changed the majority of the recommendations. (McCracken, Tr. 4502.) A number of other items are also being considered as Staff actions. (Marsh, Frank Test. Tr. 4473 at 7-8; Marsh Tr. 4572, 4574.)

203. Gallo begins to question NRC witnesses on their judgement of whether or not they are going to recommend that the potential requirements in S.A.I. report be proposed as requirements. Each witness answers only with respect to his division's recommendations. (Tr. 4732.)

204. Marsh states that the S.A.I. recommendations and NUREG-0844 will probably be appendices to a long memorandum on the requirements which must be implemented, and this memo will go to Licensees and Applicants. (Marsh, Tr. 4753-4754.) It would be a 10CFR 50.54 letter that allows agencies to require changes based on concerns, etc. NO REG GUIDE CHANGES however. But could generate changes in the Standard Review Plan. (Marsh Tr. 4755-4756.)

205. Pages 4733-4750 of the Transcript of this proceeding enumerates the potential requirements in the S.A.I. report that the Division of Systems Interaction and Engineering, the Division of Engineering, and the Division of Safety Technology in the NRC all agree be recommended for implementation. (Tr. 4733-4750.)

206. Marsh states that S.A.I. requirements are pretty much already implemented at Byron and that there is no consideration to exclude any plant from backfitting requirements of NRC via S.A.I. review. But it is really up to committee for review of generic requirements. (Marsh Tr. 4572.)

207. Marsh testifies that the S.A.I. Report is still under staff review and is not yet complete. Anticipates formulation of overall recommendations to be forwarded to the committee for review of generic requirements towards end of May. SEVERAL STEPS yet to be completed before S.A.I. recommendations become requirements, including ACRS and commission review and public comment period. (Tr. 4477-78.)

208. The actions under consideration are aimed at improving and gaining

understanding of overall problem of steam generator tube degradation, not to extend the licensing basis. (Marsh, Frank Test., Tr. 4473 at 8; Marsh Tr. 4786.)

209. As a result of the TMI accident, TMI action plan 1.C.1 requires the industry to upgrade emergency operating guidelines and procedures to cover multiple failure events which fall outside the required design envelope assumptions for safety analyses. (Marsh Test. Tr. 4473, at 8.)

210. These events were not analyzed in order to show conformance with existing regulations. The idea was to develop emergency operating procedures that go well beyond the design basis accidents in the remotest possibility that they could occur. (Marsh Tr. 4786.)

211. In this context, the Staff and vendors are analyzing a variety of such events, including coincident steam generator tube ruptures and LOCAs and coincident steam generator tube rupture and steam line breaks. The results of a recent Staff analysis are discussed in NUREG-0937. Id.

212. The S.A.I. Report did not perform its own multiple tube failure analysis but did review NRC's MTFA. (Tr. 4483.)

213. After TMI, and the concern for improved operating procedures, the Westinghouse Owners Group undertook a generic development of guidelines to cover all emergency operating procedures. These generic guidelines have been submitted to the NRC for approval. (Butterfield, Tr. 6234.)

214. The Westinghouse generic emergency response guidelines have been used as a basis for the development of the Byron operating procedures. (Butterfield Tr. 6134-44.) Emergency operating procedures being developed should help the Byron operators to respond to the various compound accidents discussed at the hearing once they occur. (Butterfield, Tr. 6233; Bridenbaugh Tr. 6508.)

across the wall for a non-instrumented tube. Initial fluid testing by Westinghouse indicates vibrational characteristics between the two types of tubes differ less than one percent. (Timmons, Tr. 6252-6253)

215. In place of tube expansion, Westinghouse considered at one point the insertion of either solid rods or cables or something inside potential high vibration tubes, but did not proceed with it because such devices would not provide a significant amount of damping, or neccessarily lead to reduction in the vibrations of the tube, though it would stabilize the tubes so that they could not sever and become loose parts within the steam generator. (Timmons, Tr. 6259)

216. Furthermore it would take a significant amount of resources to design and manufacture a sufficient number of these devices to be able to apply them in the plants in any short period of time. (Timmons, Tr. 6259-6260)

217. A 70/30 feedwater split at Krsko would translate into approximately a 75/25 split at Byron but such a reduction in main nozzle feed flow was not thought neccessary at Byron if a 90/10 split was used in conjunction with 100 expanded tubes. (Timmons, Tr. 6262)

218. Krsko is presently operating at 100% power on a 70/30 main feedwater split with no expanded tubes. The 70/30 non-expanded split at Krsko is not considered by Westinghouse to be a short-term safety concern, in terms of some tube wear, but rather a long-term concern. Krsko will undergo further modification and expand 100 tubes also, and operate on a 80/20 split. (Timmons, Tr. 6263-6264)

219. If Byron is the first plant to experiment with the Westinghouse modifications, Westinghouse intends to instrument it. (Timmons, Tr. 6304,6305)

220. The latest information identified in page 5 of Rajan's prefiled testimony consisted of the general identification of the tubes that will be expanded, their matter of expansion and supporting data from model tests which justified the selection of the tubes. This information was presented to the NRC and Rajan

NRC Staff review

221. Contrary to Applicant's opinion, the efficacy of the Westinghouse proposed midifications has not been the subject of an extensive review and verification process by NRC Staff. (Timmons, Tr. 6276-81. 6044-45, Butterfield, Tr. 6044-45)

222. Frank states that Applicant has to submit to Staff their recommendations for operation with the modifications. Nothing has formally been presented to Staff by Applicant or Westinghouse.

223. Dr. Rajan is not a competent witness for Staff in establishing the empirical basis for Staff's interim conclusion on page 5 of his revised prefiled testimony that "Based on Staff's preliminary review of the proposed modifications, the objective of mimimizing tube degradation associated with flow-induced vibrations will be accomplished by these modifications." His familiarity with the data Westinghouse recieved from operating plants, scale model testing, and Krsko tube expansion, is not sufficient to objectively reach that conclusion. It is not an empirical conclusion reached by review of the actual data. Instead he formed it on basis of View-graphs presented to Staff by Westinghouse as data summations. (Rajan, Tr. 4640-4657)

224. Except for his personal notes, Rajan has no formal submission or report from Westinghouse on results of scale model tests. (Rajan, Tr. 4653)

225. The Staff review of the proposed modifications will be completed prior to plant operation, (Rajan, Test. at 5, Tr. 4473) and a safety evaluation report issued following its implementation at Byron. (Tr. 4637, 4678, Rajan)

Unresolved Safety Issue A-3.

226. USI A-3 is an unresolved safety issue which will not be fully resolved by the NRC for several more months.

227. A primary objective of the steam generator USI program is to ensure that tubes are plugged before they corrode to a significant degree that they have potential for rupturing in subsequent operation. (McCracken Tr. 4714.) The objective of the program is to control degradation to enable the maintenance of tube wall integrity under both operating and accident conditions. (McCracken Tr. 4715; Frank Tr. 4715.)

228. In Staff and Applicant's opinion, despite the retention of USI A-3 an an unresolved safety issue, the dimensions of the more typical tube degradation have been reduced. (McCracken, Tr. 4799.)

229. A graph prepared by EPRI, and endorsed by the Staff, shows the relative number of tubes plugged verses the total number of tubes in service between 1972 and 1980. (McCracken Tr. 4797.) This graph shows the number of tubes that plugged due to phosphate wastage or thinning, denting, and other related problems. The graph demonstrates that 1977 was the height of its denting problem. This is when the Surry steam generators and Turkey Point steam generators went through so much tube plugging they had to be replaced, and then, of course, ceased to be a problem. (McCracken, Tr. 4797-98)

230. Once identified in 1976 and 1977, after the shift to all volatile chemistry, the industry became aware of what it took to reduce denting, and a decrease in the amount of denting and other corrosion in all units was seen. This specific trend has continued to the present. (Id.)

231. Things were continuing to get better and the industry was, in fact, doing what it needed to do to resolve steam generator corrosion, in fact, doing what it needed to do to resolve steam generator corrosion problems, till

flow-induced vibration came to complicate things. (Tr. 4798, McCracken)

232. Staff resolution of the issue is not complete. It is almost exactly at the same point as in 1981 when they said it would be resolved in early 1982. (Bridenbaugh, Tr. 6477-6478)

233. Staff has extimated previously the time of resolution of task A-3 and been in error. NUREG-0886 estimated early 1982. Staff now says it will be done by mid-1983. The Ginna event has delayed resolution by introducing need to consider multiple tube failures. (Bridenbaugh, Test. at 6-7, Tr.)

234. The recommendations in NUREG-0651 are also included in Staff's generic program as in Nureg-0844, a draft document, not yet final. (Marsh, Tr. 4801, 4576)

235. There are no recommendations contained in Nureg-0844 that have not been the subject of evidentiary examination in this hearing. Further, all in 0844 are embodied in the NRC's current set of recommendations. (Marsh, Tr. 4800)

236. The decision as to whether NRC requirements developed as part of the resolution of USI A-3 must be retrofitted into operating nuclear power plants is a decision that must be made by the Committee for the Review of Generic Requirements. There is no consideration at this time to exclude any plant from backditting in order to meet the NRC's requirements to resolve USI A-3. (Marsh, Tr. 4572)