NUREG-0844

NRC Integrated Program for the Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity

Final Report

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

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ABSTRACT

This report presents the results of the NRC integrated program for the resolution of Unresolved Safety Issues (USIs) A-3, A-4, and A-5 regarding steam generator tube integrity. A generic risk assessment is provided and indicates that risk from steam generator tube rupture (SGTR) events is not a significant contributor to total risk at a given site, nor to the total risk to which the general public is routinely exposed. This finding is considered to be indicative of the effectiveness of licensee programs and regulatory requirements for ensuring steam generator tube integrity in accordance with 10 CFR 50, Appendices A and B.

This report also identifies a number of staff-recommended actions that the staff finds can further improve the effectiveness of licensee programs in ensuring the integrity of steam generator tubes and in mitigating the consequences of an SGTR. As part of the integrated program, the staff issued Generic Letter 85-02 encouraging licensees of pressurized water reactors (PWRs) to upgrade their programs, as necessary, to meet the intent of the staff-recommended actions; however, such actions do not constitute NRC requirements. In addition, this report describes a number of ongoing staff actions and studies involving steam generator issues which are being pursued to provide added assurance that risk from SGTR events will continue to be small.

The staff will continue to monitor steam generator operating experiences as an indicator of the effectiveness of licensee programs for ensuring steam generator tube integrity. As has been true in the past, the staff may impose additional requirements (pursuant to applicable regulations) to continue to assure that licensees are implementing adequately effective programs where and if such action is determined to be necessary on the basis of operating experience or as a result of ongoing staff actions and studies.

The staff concludes that with final publication of this report, USIs A-3, A-4, and A-5 are technically resolved.

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ABBREVIATIONS

ACRS	Advisory Committee on Reactor Safeguards
ADV	atmospheric dump valve
AFW	auxiliary feedwater
AIF	Atomic Industrial Forum, Inc.
AIT	Augmented Inspection Team
ALARA	as low as reasonably achievable
ASME	American Society of Mechanical Engineers
ATWS	anticipated transients without scram
AVT	all-volatile treatment
BAST	boric acid storage tank
B&PV	boiler and pressure vessel
B&W	Babcock & Wilcox
CE	Combustion Engineering
CFR	Code of Federal Regulations
CI	containment isolation
CISIP	condenser inservice inspection program
DHR	decay heat removal
DNB	departure from nucleate boiling
DST	Division of Safety Technology
EC	eddy current
ECCS	emergency core cooling system
ECT	eddy current test
ENS	emergency notification system
EOF	emergency operations facility
EOP	emergency operating procedure
EPRI	Electric Power Research Institute
FPL	Florida Power and Light
FSAR	Final Safety Analysis Report
GDC	general design criterion
GIMCS	Generic Issue Management Control System
gpd	gallons per day
gpm	gallons per minute
HHSIP	high head safety injection pump
HPI	high-pressure injection
HPSIP	high-pressure safety-injection pump
ID	inside diameter
IE	Office of Inspection and Enforcement
INEL	Idaho National Engineering Laboratory
INPO	Institute of Nuclear Power Operations
IRC	Incident Response Center
ISI	inservice inspection
LANL	Los Alamos National Laboratory
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LPMS	loose-parts monitoring system
LPSI	low pressure safety injection
MFLB	main feedline break
MPA	multi-plant action

MSIV	main steam isolation valve
MSLB	main steam line break
NDE	nondestructive examination
NSSS	nuclear steam supply system
OD	outside diameter
OL	operating license
ORE	occupational radiological exposure
OTSG	once-through steam generator
PASNY	Power Authority of the State of New York
PCI	pellet-cladding interaction
PORV	power-operated relief valve
PTS	pressurized thermal shock
PWR	pressurized water reactor
QA	quality assurance
QC	quality control
RCP	reactor coolant pumps
RCS	reactor coolant system
RES	Office on Nuclear Regulatory Research
RPS	reactor protection system
RG	regulatory guide
RG&E	Rochester Gas and Electric Company
RHR	residual heat removal
RPAM	Regional Public Affairs Manager
RWST	refueling water storage tank
RY	reactor year
SAI	Science Applications, Inc.
SG	steam generator
SGGP/ SGTIP	Steam Generator Group Project/ Steam Generator Tube Integrity Program
SGOG	Steam Generator Owners Group
SGTR	steam generator tube rupture
SI	safety injection
SIS	safety injection system
SMUD	Sacramento Municipal Utility District
SRP	Standard Review Plan
STS	Standard Technical Specifications
SV	safety valve
SWCP	secondary water chemistry program
TAP	Task Action Plan
TD AFP	turbine-driven auxiliary feedwater pump
TMI	Three Mile Island
TSC	technical support center
TV	television
TVA	Tennessee Valley Authority
USI	unresolved safety issue
W	Westinghouse
WOG	Westinghouse Owners Group
WPSC	Wisconsin Public Service Corporation

NRC INTEGRATED PROGRAM FOR THE RESOLUTION OF UNRESOLVED SAFETY ISSUES A-3, A-4, AND A-5 REGARDING STEAM GENERATOR TUBE INTEGRITY

1 INTEGRATED PROGRAM OVERVIEW

1.1 Background

Degradation of steam generators (SGs) manufactured by each of the three pressurized water reactor (PWR) vendors has resulted from a combination of problems related to steam generator mechanical design, materials selection, fabrication techniques, and secondary system design and operation. To date, many different forms of steam generator tube degradation have been identified including: stress corrosion cracking, wastage, intergranular attack, denting, erosion-corrosion, fatigue cracking, pitting, fretting, support plate degradation, and mechanical damage resulting from impingement of foreign objects or loose parts on steam generator internal components. One or more of these forms of degradation have affected at least 40 operating PWRs and have resulted in extensive SG inspections, tube plugging, repair, or replacement. A detailed description of steam generator tube operating experience was provided in NUREG-0886 and, more recently, in NUREG-1063.

The majority of the SG tube failures that have occurred under normal operating conditions were small stable leaks; some required plant shutdown, inspection, and corrective actions, but others were small enough (e.g., below the leak rate limit of the Technical Specifications) so that plant operation continued until a scheduled shutdown. However, four significant steam generator tube rupture (SGTR) events have occurred in domestic PWRs since 1975.* These events occurred on February 26, 1975, at Point Beach Unit 1; September 15, 1976, at Surry Unit 2; October 2, 1979, at Prairie Island Unit 1; and January 25, 1982, at R.E. Ginna. SGTR events are defined by the NRC staff to be a primary to secondary leak in excess of the normal charging flow capacity of the reactor coolant system (NUREG-0651).

The first three of these events were evaluated in NUREG-0651. That report includes evaluations of systems response, operator actions, and radiological consequences during the three events. The event at the Ginna plant was addressed in NUREG-0909 and plant restart was evaluated in NUREG-0916. NUREG-0909 includes descriptions of the event and significant staff findings; NUREG-0916 is an evaluation of system response, operator response, steam generator inspection and repair programs, emergency preparedness, and radiological consequences.

Staff concerns which were raised relative to steam generator tube degradation stem from the fact that the steam generator tubes are a part of the reactor coolant system (RCS) boundary and that tube failures result in a loss of primary coolant. In addition, the steam generator tubes constitute a particularly

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*This report was prepared before a fifth SGTR event that occurred on July 15, 1987, at North Anna Unit 1. The implications of this event with respect to the conclusions of this report are addressed in Section 1.10.

important part of the RCS boundary since their failure allows primary coolant into the steam generators where its isolation from the environment is not fully ensured. The leakage of primary coolant into the secondary system has two major safety implications. The first is the potential for direct release of radioactive fission products to the environment, and the second is the loss of cooling water which is needed to prevent core damage. An extended uncontrolled loss of coolant outside of containment would result in the depletion of the initial RCS inventory and emergency core cooling system (ECCS) water without the capability to recirculate the water.

The NRC regulations (Title 10 of the Code of Federal Regulations (10 CFR)) establish the fundamental requirements relative to steam generator tube integrity. Specifically, the General Design Criteria (GDC) of 10 CFR Part 50, Appendix A, state that the reactor coolant system boundary shall "have an extremely low probability of abnormal leakage" (GDC 14), shall "be designed with sufficient margin" (GDC 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing...to assess...structural and leak tight integrity" (GDC-32).

10 CFR Part 50, Appendix B, is also pertinent to the maintenance of steam generator tube integrity. This appendix establishes quality assurance requirements for the design, construction, and operation of safety-related components. The pertinent requirements of this appendix apply to all activities affecting the safety-related functions of these components; these include, in part, inspecting, testing, operating, and maintaining.

To ensure that the regulations are met, each applicant's steam generator design, water chemistry, and inspection program are evaluated in accordance with regulatory guidance in NUREG-0800, "Standard Review Plan," before issuing a license and a safety evaluation report is issued. PWR applicants are also required to analyze the consequences of a design-basis steam generator tube rupture. These analyses must show that the offsite radiological consequences, considering the most limiting set of initial conditions and single failure, do not exceed a small fraction of the limits of 10 CFR Part 100.

Once a plant is in operation, the licensee demonstrates continued compliance with the regulations through periodic inspections, using the inspection criteria in the plant Technical Specifications. Tubes which are found to be defective, as defined in the plant Technical Specifications, are repaired or removed from service. To verify acceptable performance during operating periods between inspections, the plant Technical Specifications require shutdown if excessive primary to secondary leakage or excessive primary side activity occurs. Operating plants which experience primary to secondary leakage in excess of Technical Specification limits, or abnormal degradation as evidenced by the periodic inspections, may be required on a case-by-case basis to implement additional measures to provide added assurance of continued compliance with the regulations. The additional measures may include items such as increased inspection frequencies, lower Technical Specification limits for primary to secondary leakage, or improved water chemistry/corrosion control.

1.2 Development of Integrated Program

Steam generator tube integrity was designated an unresolved safety issue (USI) in 1978, and Task Action Plans (TAPs) A-3, A-4, and A-5 were established to

evaluate the safety significance of degradation in Westinghouse, Combustion Engineering, and Babcock & Wilcox steam generators, respectively. These studies were later combined into one effort because many problems being experienced with steam generators supplied by these vendors were similar. The staff prepared a draft report regarding this issue, which was originally intended for publication as NUREG-0844, "Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity." The draft report primarily considered corrosion-related failure mechanisms, including the "denting" mechanism, since those failures were the main concern during the period when most of the technical studies were performed.

In May 1982, subsequent to the issuance of NUREG-0909 and NUREG-0916 regarding the Ginna SGTR event, the staff initiated an integrated program to consider the lessons learned from the Ginna SGTR event and from the three previous domestic SGTR events (NUREG-0651), and to consider the recommendations identified in Section 9 of the draft USI report above. The draft USI report (now entitled "Initial Staff Recommendations from the NRC Program for the Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity") is available publicly as an enclosure to an NRC memorandum, SECY 84-13, dated January 11, 1984. The objective of the integrated program was to complete resolution of USIs A-3, A-4, and A-5, including identification of requirements that should be imposed on operating license (OL) applicants and licensees and identification of further efforts that should be undertaken by the NRC. The program report herein describes the results of this integrated program and supersedes the draft USI report above as the technical resolution of these USIs.

The staff initially considered a number of issues pertaining to steam generator tube integrity and mitigation of SGTR events as part of the integrated program. These issues were categorized as (1) those appropriate for consideration by the staff as potential actions for all plants with steam generators (hereafter referred to as potential industry actions), or (2) those issues warranting further staff study, already being considered as part of an existing regulatory program, or those issues for which corrective actions have already been taken. Issues within the latter three categories are discussed in Section 4 of this report.

The issues within the first category, which had been identified as potential industry actions, were grouped into the technical areas listed below and were subjected to a value-impact evaluation by the staff. Section 2 of this report provides a description of each potential industry action, the initial basis for its consideration, and the results of the value-impact analysis for each item. These issues are:

(1) Prevention and Detection of Loose Parts or Foreign Objects

- (a) Secondary Side Visual Inspection and Improved Quality Assurance/ Quality Control (QA/QC) Procedures
- (b) Loose-Parts Monitoring System

(2) Inservice Inspection of Steam Generator Tubes

- (a) Supplemental Tube Inspections
- (b) Full-Length Tube Inspections

(c) Denting Inspections
(d) Steam Generator Inservice Inspection Interval
(e) Inspections Following Shutdown for Repair of Leakage

(3) Improved Eddy-Current Test Techniques

(4) Upper Inspection Ports

(5) Secondary Water Chemistry Program

(6) Condenser Inservice Inspection Program

(7) Stabilization and Monitoring of Degraded Tubes

(8) Primary to Secondary Leakage Limits

(9) Coolant Iodine Activity Limit

(10) Reactor Coolant System Pressure Control

(11) Safety Injection Signal Reset

(12) Containment Isolation and Reset

1.3 Scope of Value-Impact Evaluation

The value-impact analysis of the potential industry actions, discussed in Section 2, addressed the potential for reductions in (1) the probability of core melt, (2) the probability of significant radiological releases comparable to NUREG-75/014* PWR release categories 8 and 9 during SGTR events not leading to core melt, (3) public risk, and (4) occupational radiological exposure (ORE).

Economic costs were also a consideration of this analysis. Net economic costs were considered in relation to the benefits to public health and safety. Net economic benefits (deriving from the cost-effectiveness of some of the potential industry actions) were considered neither as a barrier nor a basis for the disposition of the potential industry actions under consideration.

The staff's evaluation considered input from a report by the staff's contractor, Science Applications, Inc. (SAI), "Value-Impact Analysis of Recommendations Concerning Steam Generator Tube Degradation and Rupture Events." The SAI report provided much of the basis for the staff's evaluation of the effectiveness of the potential industry actions in reducing the incidence of steam generator tube degradation, tube ruptures, and occupational radiological exposures and for the staff's evaluation of the potential cost benefits and cost impacts.

The SAI report includes an assessment of the risk reduction potential associated with prevention of SGTR events involving a single tube. The staff reviewed this analysis and performed an independent analysis of the probability of various scenarios involving ruptured tubes as described in Section 3. The staff's risk analysis included consideration of risk from scenarios involving more than a single ruptured tube.

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*Formerly WASH-1400.

The staff's value-impact analysis also considered industry comments as discussed in Section 1.4 below.

1.4 Industry Comments

On December 9, 1982, the NRC staff transmitted Generic Letter 82-32, "Potential Steam Generator Related Generic Requirements," to all pressurized water reactor plant licensees for their information. This letter transmitted a draft value-impact report by SAI, and advised that any comments that the recipients chose to make on that report or on the probability and consequences of multiple tube ruptures would be considered in the staff's final value-impact report if the comments were provided in a timely manner. The SAI report was also sent to the nuclear steam supply system (NSSS) vendors: Westinghouse, Combustion Engineering, and Babcock & Wilcox. The staff also invited industry comments on the program during two public meetings (July 29, 1982 and July 5, 1983) with the Steam Generator Owners Group (SGOG), which is sponsored by the Electric Power Research Institute (EPRI), and other interested parties.

Letters received from industry in response to the staff's initiatives above are listed in Appendix A. Industry comments specific to the potential industry actions were considered by the staff and are discussed in Section 2. General comments included the following:

(1) General agreement exists throughout industry that single SGTR events are not dominant contributors to risk.

(2) Westinghouse (letter, Feb. 15, 1983) stated that its analyses have also demonstrated that multiple tube rupture events are not a dominant contributor to risk.

(3) Most respondents appear to be in agreement that many of the potential industry actions under consideration by the NRC staff involve the type of actions which should generally be followed by industry. Most often cited by industry were actions pertaining to the prevention and detection of loose parts and foreign objects, full length tube inspections, maximum steam generator inspection intervals, and high quality secondary water chemistry. Specific comments by industry concerning these actions are discussed in Section 2.

(4) Some respondents question the need for regulatory action in these areas on the grounds that the benefits produced are primarily economic rather than safety related.

(5) Several respondents emphasized the need for ensuring that any requirements are sufficiently flexible to accommodate plant-specific issues and differences in steam generator design.

(6) SGOG comments included the following (letters, September 30, 1982, April 24, 1984, and October 1, 1984):

    (a) Steam generators and PWR plants were designed with the expectation that tubes in steam generators would leak. PWRs have been designed and analyzed to accommodate such rupture.

(b) Complete elimination of the potential for tube leakage or rupture is not a realistic or necessary objective.

(c) Neither the utilities, the NRC, nor the public is well served by the uniform application of generic requirements to solve problems with complex site-specific causes. This is particularly true where the consequences of problems are economic rather than safety issues.

(d) Concern for steam generator reliability led the SGOG to voluntarily prepare secondary water chemistry guidelines based on extensive research results. The SGOG understands that non-member utilities also are following the guidelines out of the same concern. With such evidence of utility action, imposition of the guidelines as an NRC requirement is unnecessary and would be counterproductive; i.e., it would be another indication that aggressive voluntary action by the industry does not prevent regulation with all its associated "red tape."

(e) The SGOG strongly endorses the position of the Advisory Committee on Reactor Safeguards (ACRS) documented in an ACRS letter to NRC Chairman Nunzio Palladino on October 18, 1983. This position is that the NRC proposals have considerable merit but that their implementation will not result in a significant reduction of risk to health and safety of the public. Rather, their implementation would result in a reduced rate of challenge to the safety systems and in economic benefits to the consumers of electric power. Therefore, the ACRS recommended that the NRC proposals not be implemented as new regulatory requirements but instead as recommended industry actions.

(f) Very substantial progress has been made and is continuing to be made by the PWR industry in the United States in improving the reliability of steam generator operation and USIs A-3, A-4, and A-5 can be considered resolved.

1.5 Risk from SGTR-Related Causes

The staff's risk analysis, which is described in Section 3, indicates that the core melt probability from SGTR-related causes is small, about 5.3×10^{-6}/reactor-year (RY) for Babcock and Wilcox (B&W) plants and 3.9×10^{-6}/RY for Westinghouse (W) and Combustion Engineering (CE) plants. These probabilities are a relatively small fraction (10% or less) of the overall probability of core melt events from all causes based on probabilistic risk assessments that have been performed for a number of PWRs. The corresponding risk to the public is estimated to be limited to 2.4×10^{-3} (B&W plants) and 1.7×10^{-3} (W and CE plants) latent fatalities/RY and 4.6×10^{-6} (B&W plants) and 4.3×10^{-6} (W and CE plants) early fatalities/RY from SGTR related accidents associated with core melt (see Table 7, in Section 3).

Initiating event SGTRs, whose frequency is known from operating experience, contribute only 1.1×10^{-6}/RY to the above core melt probability estimates. The balance of the above core melt probability estimates is associated with consequential event SGTRs whose frequency is more uncertain, particularly consequential SGTRs involving multiple tube ruptures. The staff has made a number of conservative assumptions to ensure that actual multiple tube frequencies are

not grossly underestimated. However, this may have resulted in conservative estimates of the frequency of multiple tube ruptures and the corresponding probability of core melt.

The staff also evaluated the potential for significant radiological releases (comparable to NUREG-75/014* PWR release categories 8 and 9) during SGTR events not leading to core melt. These events primarily involve SGTRs occurring in conjunction with a stuck-open steam generator safety valve so that primary coolant leaking into the steam generator can subsequently be released to the environment. The probability of SGTRs occurring in conjunction with a stuck-open safety valve is estimated to be 4.9×10^{-4}/RY for B&W plants and 2.3×10^{-4}/RY for W and CE plants. Site-boundary doses would typically be expected to be small relative to the consequence limits of 10 CFR Part 100 based on best estimate assumptions regarding coolant iodine activity concentrations, iodine spiking, and meteorology. The use of conservative assumptions regarding these parameters, which are similar to design basis assumptions, leads to site-boundary dose estimates which may challenge or exceed the 10 CFR Part 100 limits; however, the frequency of such doses is significantly less than the above 2.3×10^{-4} to 4.9×10^{-4}/RY estimate. The staff estimates public risk from non-core-melt releases to be very small: 7.0×10^{-7} latent fatalities/RY for B&W plants and 3.0×10^{-7} latent fatalities/RY for W and CE plants.

On the basis of the evaluation above, the staff finds that SGTR events beyond the design basis do not contribute a significant fraction of the early and latent cancer fatality risks associated with reactor events at a given site. Furthermore, the risk assessment indicates that the increment in risk associated with SGTR events is a small fraction of the accidental and latent cancer fatality risks to which the general public is routinely exposed. These findings reflect in part the effectiveness of existing steam generator related requirements (see Section 1.1) for ensuring steam generator tube integrity. These include requirements which have been imposed on a case-specific basis in response to certain tube degradation problems experienced at one or more sites. However, these findings also reflect industry efforts since the mid-1970s to improve steam generator reliability. Steam generator reliability involves not just minimizing the potential for SGTRs, but also minimizing (1) the incidence of small tube leaks which may lead to unscheduled plant outages, (2) the need for extensive steam generator repairs, and (3) the need for steam generator replacement. Reliability improvements, therefore, have provided significant economic benefits to the industry in addition to enhanced tube integrity.

1.6 Disposition of Potential Industry Actions

1.6.1 Staff Recommended Actions

In view of the relatively low risk estimates associated with SGTR events, the staff has concluded that issuance of the potential industry actions in Table 1 as generic requirements is not warranted at this time. However, the staff's

*Formerly WASH-1400

value-impact evaluation indicates that several of these potential industry actions as a group are effective and cost beneficial measures for significantly reducing (1) the incidence of tube degradation, (2) the frequency of tube ruptures and the corresponding potential for significant non-core melt releases, and (3) occupational exposures, and are consistent with good operating and engineering practice. As a group, these actions are also effective measures for mitigating the consequences of SGTRs. Adoption of these actions by licensees would further reduce public risk and provide added assurance that risk will continue to be small. These actions have been designated as staff recommended actions and involve the following topics:

(1) secondary side visual inspections and improved QA/QC procedures for prevention and detection of loose parts

(2) inservice inspection of steam generator tubes: (a) full length tube inspections, (b) maximum steam generator inspection intervals

(3) secondary water chemistry program

(4) condenser inservice inspections

(5) primary to secondary leakage limits

(6) coolant iodine activity limits

(7) evaluation of safety injection reset

Details of the staff recommended actions and the staff's value-impact evaluation of these actions are provided in Section 2.

1.6.2 Potential Industry Actions Warranting Further Staff Study

Apart from potential industry actions which the staff has dispositioned as staff recommended actions, the staff has concluded that others of these actions merit further study by the staff (staff actions). As indicated in Table 1, these actions involve issues relating to supplemental tube inspections, inspecting dents in tubes, improving eddy-current inspection techniques for steam generator tubes, and controlling pressure in reactor coolant systems during steam generator rupture events. These potential actions and the bases for the disposition of these actions as staff actions are discussed in Section 2. In addition, these actions have been added to the total list of staff action items stemming from the integrated program for resolution of USIs A-3, A-4, and A-5, which is described in Section 1.8 below, and in additional detail in Section 4.

1.6.3 Deleted Potential Industry Actions

The staff has concluded that the remainder of the potential industry actions identified in Table 1 are not appropriate as generic staff recommended actions, nor do these actions warrant additional study as a staff action. The potential industry actions which have been deleted involve the areas identified below. These actions and the bases for the staff's disposition of these actions are discussed in further detail in Section 2. As appropriate, the staff may review individual plants relative to these issues. These issues are

(1) prevention and detection of loose parts (loose-parts monitoring systems)

(2) inservice inspection program (inservice inspections following shutdown for repair of leakage)

(3) upper inspection ports

(4) stabilization and monitoring of degraded tubes

(5) containment isolation and reset

1.7 Issuance of Generic Letter Regarding Staff Recommended Actions and Subsequent Follow-up Actions

As part of the technical resolution of USIs A-3, A-4, and A-5, the staff issued NRC Generic Letter 85-02 to all PWR licensees and applicants to inform them of the staff recommended actions. In addition, PWR licensees and applicants were requested to describe their overall steam generator programs and how these programs compare with the staff recommended actions.

Licensee and applicant letters responding to Generic Letter 85-02 are listed in Appendix A. The staff's assessment of these responses was reported to the Commission in an NRC memorandum, SECY 86-97, dated March 24, 1986. The staff concluded on the basis of this assessment that the large majority of licensees and applicants are following programs, practices, and/or procedures which are partially to fully consistent with or equivalent to the staff recommended actions. Cases where licensee programs appeared to fall short of being consistent with or equivalent to the staff's recommended actions were not considered indicative, in and of themselves, of significant risk or non-compliance with the regulations, and with one exception noted below for Oconee Units 2 and 3, and Arkansas Nuclear One, Unit 1 (ANO-1), none appeared to warrant regulatory action at this time.

It was stated in SECY 86-97 that the staff would inform licensees of its findings relative to their plants as part of Multi-Plant Action (MPA) C-16. Because this task has such low safety significance, the staff has dropped these plans.

It is implicit in the findings stemming from the integrated program herein that licensees must continue to be vigilant against new or unusual problems which may necessitate preventive, diagnostic, and/or corrective actions beyond the licensee's normal practice. The staff will continue to monitor steam generator operating experiences as an indicator of the effectiveness of licensee programs. As has been the case in the past, the staff may impose additional requirements on a site-specific or generic basis if such action is determined to be necessary on the basis of operating experience or the results of ongoing staff programs discussed in Section 1.8 and in Section 4 of this report to provide continued assurance of steam generator tube integrity in accordance with 10 CFR Part 50, Appendices A and B. Any new requirements would be subject to the provisions of 10 CFR 50.55a, paragraph (g)(6)(ii), or 10 CFR 50.109, as applicable.

In SECY 86-97, the staff indicated its concern that the existing Technical Specification limit on allowable primary to secondary leakage at Oconee Units 2 and 3 may not be a sufficiently effective limit for preventing tube ruptures.

Since issuing SECY 86-97, the staff learned that this concern was also applicable to ANO-1. Each of these three units has operating procedures which incorporate leakage limits that appear to be largely consistent with those recommended by the staff in Generic Letter 85-02. However, because of the importance of primary to secondary leak rate limits in ensuring tube integrity, the staff believes that appropriate limits should also be included in the Technical Specifications for these units. At the staff's request, the licensees for these units have recently submitted proposed Technical Specification limits which are under review by the staff.

Finally, the staff acknowledges that the industry has made significant progress in recent years in improving steam generator reliability. Industry-sponsored research by SGOG and EPRI has resulted in a number of improvements in steam generator and secondary system design and in the availability to utilities of improved operating practices, non-destructive examination (NDE) methods, and preventive and corrective measures pertaining to specific problems. Noteworthy achievements in this regard have included issuance of the SGOG/EPRI "PWR Secondary Water Chemistry Guidelines," Revision 1, June 1984, and the SGOG/EPRI "PWR Steam Generator Inspection Guidelines," Revision 1, July 1985. These improvements are gaining increasing acceptance and application throughout the industry, tending to further reduce risk at the affected plants and to provide added assurance that risk from steam generator-related causes will continue to be small.

1.8 Staff Actions and Studies

The integrated program has identified a number of staff actions and studies related to steam generator tube integrity, plant systems response, human factors considerations, radiological consequences, and organizational response to events. These staff actions are discussed in Section 4 and are summarized in Table 2. A number of these actions have been completed, as noted in Table 2. Other staff actions identified in Table 2 involve broad generic issues extending beyond strictly steam generator-related issues. These include issues being addressed by another USI program (USI-49, "Pressurized Thermal Shock") and by currently approved staff implementation plans for on-going generic issue reviews including "Improved Accident Monitoring" (NRC Generic Letter 82-33); "Reactor Vessel Inventory Measurement" (TMI Task Action Plan (TAP) II.F.2, NRC Generic Letter 82-28); "Guidance on Reactor Coolant Pump Trip" (TMI TAP II.K.3.5, NRC Generic Letter 82-33); "Control Room Design" (TMI TAP I.D.1, NRC Generic Letter 82-33); and "Improved Emergency Operating Procedures" (TMI TAP I.C.1, NRC Generic Letter 82-33). Completion of these broad generic tasks is considered to be outside the scope of the staff's integrated program to resolve USIs A-3, A-4, and A-5 regarding steam generator tube integrity.

The remaining staff actions identified in Table 2 and discussed in Section 4 involve other issues related to steam generators. As noted in Table 2 and discussed further in Section 4, a number of these remaining staff actions are relatively low priority tasks which will remain inactive pending completion of higher priority tasks and availability of staff resources. Others of these remaining staff actions, as indicated in Table 2, are actively being pursued as part of Generic Issue 135, "Steam Generator and Steam Line Overfill Issues," and/or the Steam Generator Group Project/Steam Generator Tube Integrity

Program sponsored by the NRC Office of Nuclear Regulatory Research. In view of the low risk estimates associated with SGTR events, the staff concludes that the resolution of USIs A-3, A-4, and A-5 is not contingent upon completion of these tasks. However, these tasks will help ensure that risk continues to be low and may lead to proposals for revising existing regulatory guidance and possibly requirements concerning steam generator tube inspections and repairs, revisions to the Standard Review Plan concerning the design basis SGTR, and resolution of the steam generator/steam line overfill issue. The potential regulatory and safety benefits and cost of implementation will be assessed for any proposals stemming from these activities. If justified by this cost/benefit analysis, additional or revised regulatory guidance or requirements may be issued.

Of special note is the comprehensive assessment of steam generator inspection programs, including inspection sampling strategies and eddy current test practices, being performed as part of the Steam Generator Group Project/Steam Generator Tube Integrity Program (SGGP/SGTIP) sponsored by the NRC Office of Nuclear Regulatory Research. There is increasing evidence from this program and from operating experience of deficiencies in the reliability of current field inspection practices, although the staff does not believe that significant risk to public health and safety is involved. The SGGP/SGTIP program is expected to lead to improved regulatory guidance which addresses these deficiencies. This program may also lead to new augmented inservice inspection requirements (pursuant to 10 CFR 50.55a) should it be determined from this program that added assurance of steam generator tube integrity is needed. In addition to staff efforts in this area, SGOG/EPRI will shortly be issuing Revision 2 to the "PWR Steam Generator Inspection Guidelines" to address inspection reliability deficiencies experienced to date.

1.9 Public Comments

A draft version of this report was issued for public comment in April 1985. The comment letters received are listed in Appendix A. Most of the comments received focused on the merits of the staff recommended actions issued in NRC Generic Letter 85-02. These comments were generally within the scope of earlier comments discussed in Section 1.4, which were considered by the staff in the development and issuance of the staff recommended actions. None of the comments received regarding the draft version of this report took issue with the staff's major findings; namely that (1) SGTRs do not contribute significantly to the risks of nuclear plant operation nor to the risks to which the general public is routinely exposed and (2) USIs A-3, A-4, and A-5 can be considered resolved.

One utility, Carolina Power and Light Company, expressed the concern that the draft version of this report could be interpreted to mean that implementation of the staff recommended actions in Generic Letter 85-02 is necessary in order to comply with 10 CFR Part 50, Appendices A and B (letter dated July 18, 1985). Such an interpretation would be contrary to the staff's intent as is now explained in Section 1.7.

1.10 Implications of July 15, 1987 SGTR Event at North Anna Unit 1

The material in this report generally predates the most recent SGTR event which occurred on July 15, 1987 at North Anna Unit 1. That failure has been attributed to a rapidly propagating fatigue crack caused by flow-induced vibration. The

North Anna event was addressed in NRC Augmented Inspection Team (AIT) Report Nos. 50-338/87-24 and 50-339/87-24 and in the staff's safety evaluation (letter, December 11, 1987) authorizing North Anna Unit 1 to operate at 100 percent of licensed power. The AIT report includes a description of the event and staff findings pertaining to the systems response, operator response, and radiological consequences. The safety evaluation addresses the causes of the failure and the corrective actions taken to prevent a recurrence.

Generic implications of the North Anna event have been addressed in NRC Bulletin 88-02. The bulletin requests that licensees and applicants perform specified inspections and analyses to determine whether their plants are susceptible to rapidly propagating fatigue cracks and that they implement corrective actions if necessary. These actions will ensure that steam generator tube integrity will continue to be maintained in accordance with 10 CFR Part 50, Appendices A and B, and that risk from SGTR related causes will continue to be low. Thus, the conclusions of this report, as stated in Section 1.11 below, remain valid.

1.11 Conclusions Stemming from the Integrated Program

(1) SGTRs do not contribute a significant fraction of the early and latent cancer fatality risks associated with reactor events at a given site. The increment of risk associated with SGTR events is a small fraction of the accidental and latent cancer fatality risks to which the general public is routinely exposed. This finding is considered to be indicative of the effectiveness of licensee programs and regulatory requirements for ensuring steam generator tube integrity in accordance with 10 CFR Part 50, Appendices A and B.

(2) The Commission's current rules and regulations (i.e., 10 CFR Part 50, Appendices A and B; 10 CFR 50.55a; 10 CFR 50.109; and 10 CFR Part 100) provide the staff with adequate authority to ensure that licensees are implementing programs relating to steam generator tube integrity which provide adequate protection to public health and safety.

(3) The staff has identified staff recommended actions which can further enhance the effectiveness of licensee programs for ensuring steam generator tube integrity and for mitigating the consequences of an SGTR. The staff has issued Generic Letter 85-02 to inform licensees and applicants of the staff recommended actions; however, these actions do not constitute NRC requirements.

(4) It is implicit in the conclusions stemming from the integrated program that licensees must continue to be vigilant against new or unusual problems that may necessitate preventive, diagnostic, and/or corrective actions beyond the licensee's normal practice. The staff will continue to monitor steam generator operating experiences as an indicator of the effectiveness of licensee programs. As has been the case in the past, the staff may impose additional requirements (pursuant to applicable regulations) to continue to ensure that licensees are implementing adequately effective programs where such action is determined to be necessary on the basis of operating experience or as a result of ongoing staff actions and studies.

(5) Section 4 of this report identifies a number of staff actions and studies involving steam generator issues that are being pursued to provide added assurance that risk from SGTR related causes will continue to be small.

(6) The staff concludes that with final publication of this report (NUREG-0844), USIs A-3, A-4, and A-5 are technically resolved.

Table 1 Disposition of potential industry actions

Item		Report Section	Disposition
1.	Prevention and Detection of Loose Parts		
	(a) Visual Inspection of Secondary Side and QA/QC Work Procedures	2.1.1	Staff Recommended Action
	(b) Loose-Parts Monitoring System	2.1.2	Dropped
2.	Steam Generator Tube Inservice Inspection		
	(a) Supplemental Tube Inspections	2.2.1	Staff Action
	(b) Full-Length Tube Inspections	2.2.2	Staff Recommended Action
	(c) Denting Inspections	2.2.3	Staff Action
	(d) Steam Generator Inservice Inspection Interval	2.2.4	Staff Recommended Action
	(e) Inspections Following Shutdown for Repair of Leakage	2.2.5	Dropped
3.	Improved Eddy-Current Test Techniques	2.3	Staff Action
4.	Upper Inspection Ports	2.4	Dropped
5.	Secondary Water Chemistry Program	2.5	Staff Recommended Action
6.	Condenser Inservice Inspection Program	2.6	Staff Recommended Action
7.	Stabilization and Monitoring of Degraded Tubes	2.7	Dropped
8.	Primary to Secondary Leakage Limits	2.8	Staff Recommended Action
9.	Coolant Iodine Activity Limit	2.9	Staff Recommended Action
10.	Reactor Coolant System Pressure Control	2.10	Staff Action
11.	Safety Injection Signal Reset	2.11	Staff Recommended Action
12.	Containment Isolation and Reset	2.12	Dropped

Table 2 Related staff actions and studies*

Item	Report Section	Action
1. Steam Generator Tube Integrity		
- Guidance for Sleeve Repairs	4.2.1	**
- Inspections for Denting	4.2.2	**
- Improved Eddy Current Techniques	4.2.3	Generic Issue 135 SGGP/SGTIP
- Category C-2 Inservice Inspection	4.2.4	Generic Issue 135 SGGP/SGTIP
2. Plant Systems Responses		
- Steam Generator Overfill	4.3.1	Generic Issue 135
- Reactor Coolant System Pressure Control	4.3.2	USI A-45 TMI TAP II.D.1
- Pressurized Thermal Shock	4.3.3	USI A-49
- Improved Accident Monitoring	4.3.4	Regulatory Guide 1.97 Programs, Generic Ltr. 82-33
- Reactor Vessel Inventory Measurement	4.3.5	TMI TAP II.F.2, Generic Ltr. 82-28
3. Human Factors		
- Guidance on Reactor Coolant Pump Trip	4.4.1	TMI TAP II.K.3.5, Generic Ltr. 82-33
- Control Room Design	4.4.2	TMI TAP II.D.1, Generic Ltr. 82-33
- Improved Emergency Procedures	4.4.3	TMI TAP I.C.1, Generic Ltr. 82-33
4. Radiological Consequences		
- Reassess Potential Consequences of SGTR	4.5.1	**
- Reassess Design-Basis SGTR	4.5.2	Generic Issue 135

See footnotes at end of table.

Table 2 (Continued)

Item	Report Section	Action
5. Improved Organization Response to Events		
- Seven actions are being taken by staff	4.6	6 of 7 complete

*These tasks are discussed in detail in Section 4.
**Not high priority. Will be scheduled pending availability of staff resources.

2 VALUE-IMPACT EVALUATION OF POTENTIAL INDUSTRY ACTIONS

This section discusses potential industry actions with respect to maintenance of steam generator tube integrity and mitigation of steam generator tube ruptures which were considered as part of the NRC integrated program. The basis for the consideration of these actions, the staff's value-impact findings concerning these actions, and the staff's disposition of these actions are also described. The staff's value-impact findings and the staff's disposition of the potential industry actions are summarized in Table 3.

2.1 Prevention and Detection of Loose Parts and Foreign Objects

Loose parts and foreign objects have caused two of the four domestic steam generator tube rupture (SGTR) events to date. In response, the staff identified for further consideration potential industry actions concerning (1) visual inspections of the secondary side of steam generators and quality assurance procedures governing all work performed within steam generators, and (2) loose-parts monitoring systems. As discussed below, the potential industry actions in item 1 above have been categorized as staff recommended actions. Given implementation of these actions, the staff finds there is insufficient justification to support item 2 as a staff recommended action.

2.1.1 Secondary Side Visual Inspections and Improved QA/QC Procedures

2.1.1.1 Staff Recommended Actions

Visual inspections of the steam generator secondary side and improved quality assurance/quality control (QA/QC) work procedures should be implemented for the prevention and detection of loose parts and foreign objects.

(1) Secondary-Side Visual Inspections

Visual inspections should be performed on the steam generator secondary side in the vicinity of the tube sheet, both along the entire periphery of the tube bundle and along the tube lane, for purposes of identifying loose parts or foreign objects on the tubesheet and external damage to peripheral tubes just above the tubesheet. An appropriate optical device should be used (e.g., mini-TV camera, fiber optics). Loose parts or foreign objects which are found should be removed from the steam generators. Tubes observed to have visible damage should be eddy current inspected and plugged if found to be defective.

These visual inspections should be performed (a) for all steam generators at each plant at the next planned outage for eddy current testing, (b) after any secondary-side modifications or repairs to steam generator internals, and (c) when eddy current indications are found in the free span portion of peripheral tubes, unless it has been established that the indication did not result from damage by a loose part or foreign object. PWR operating license applicants should perform such inspections as part of the preservice inspection.

For steam generator models where certain segments of the peripheral region can be shown to be inaccessible to an appropriate optical device, licensees and applicants should take alternative actions to address these inaccessible areas, as appropriate.

Licensees should take appropriate precautions to minimize the potential for corrosion while the tube bundle is exposed to air. The presence of chemical species such as sulfur may aggravate this potential, and may make exposure to the atmosphere inadvisable until appropriate remedial measures are taken.

(2) Improved QA/QC Procedures

QA/QC procedures for steam generators should be reviewed and revised as necessary to ensure that an effective system exists to preclude introduction of foreign objects into either the primary or secondary side of the steam generator whenever it is opened (e.g., for maintenance, sludge lancing, repairs, inspection operations, modifications). As a minimum, such procedures should include (a) detailed accountability procedures for all tools and equipment used during an operation, (b) appropriate controls on foreign objects such as eye glasses and film badges, (c) cleanliness requirements, and (d) accountability procedures for components and parts removed from the internals of major components (e.g., reassembly of cut and removed components).

2.1.1.2 Basis for Initial Consideration

Inspection methods and practices and material accountability controls at many PWR facilities have not proven sufficiently effective in ensuring that loose parts and foreign objects have been identified and removed before startup. For example, the accountability controls in use at Ginna (NUREG-0909 and NUREG-0916) during the removal/modification of the downcomer resistance plate in 1975, while generally consistent with NRC guidance and industry philosophy at that time, did not prevent parts of the plate from being left in the secondary side of the steam generator. Deficiencies included (1) failure to perform a post-maintenance accountability inspection of the removed resistance plate to account for all pieces, (2) no documentation to verify that an adequate barrier existed to keep material from dropping into the steam generator, and (3) failure to perform adequate post-maintenance inspection of the secondary side of the steam generator for foreign parts. Foreign objects or loose parts have also been found in the steam generators at Zion 1, Prairie Island 1, North Anna 1, San Onofre 1, Davis-Besse, Rancho Seco, Oconee 3, Point Beach 1, Cook 1, and Turkey Point 4. Several of these experiences are discussed in detail below.

Secondary-side visual inspections will also ensure that degraded conditions on the outer surface of peripheral tubes such as may be caused by loose parts or foreign objects have been adequately identified.

During the Ginna post-event activity, visual inspection with a remote TV camera revealed a number of foreign objects in the secondary side of the B steam generator. The largest object appeared to be part of the steam generator's downcomer flow resistance orifice plate which had been cut and removed in 1975 during a modification of the steam generator. This large foreign object most probably initiated the damage that led to the tube rupture. Post-rupture examination revealed that severe damage had occurred to 26 tubes in the periphery of B steam generator. These tubes were so extensively damaged that the licensee

had to remove them to protect sound tubes. In addition, portions of two fractured tubes found skewed between the tube bundle and the steam generator shell were also removed. Foreign objects were found in the A steam generator, although no tube damage occurred that was attributable to these objects.

On October 2, 1979, a tube ruptured in steam generator A of Prairie Island 1 (NUREG-0651) while the plant was operating at full power. The licensee estimated the leak rate at about 390 gpm. Visual and fiber optic inspections performed subsequent to the tube rupture incident revealed that the tube in Row 4, Column 1, had ruptured about 3 in. above the tube sheet. The rupture was a classical tube burst with a "fish-mouth" opening about 1-1/2 in. long with a maximum width of about 0.5 in. The edges of the break were observed to be worn to a "knife edge." The tubes in adjacent positions (Row 3, Column 1, and Row 2, Column 1) also showed signs of wear. All wear marks and the rupture were on the outer peripheral side of the tube bundle at approximately the same elevation. A steel coil spring, 8.5 in. long, 1.25 in. in diameter and of 3/32 in. wire diameter was found lying on the tube sheet adjacent to the defective tubes. One end of the spring was wedged between the tube sheet and a flow-blocking device (the flow-blocking device diverts flow away from the open tube lane and into the tube bundle); the other end was free to move. A visible wear pattern on the tube sheet indicated that the spring had moved back and forth during plant operation.

On February 25, 1982, while preparing for eddy-current testing of the 1B steam generator, Zion 1 station personnel discovered three pieces of a hinge about 30 in. long and 2 in. wide in the channel head plenum area of the steam generator. These fragments were later determined to have come from an aluminum nozzle cover left in the 1D steam generator during tube testing in March 1981. It is believed that the aluminum cover dissolved during reactor operation leaving behind two stainless steel hinges that had held the cover. One hinge section was found bent, but in one piece, in the 1D steam generator. The other hinge section was found in three pieces in the 1B steam generator. The licensee attributed the presence of the three pieces of hinge to the reverse flow that occurred in mid-February 1982 when reactor coolant pumps A and D were shut down. More than 1100 protruding tube ends on the inlet plenum of the 1D steam generator had been severely damaged by the loose parts necessitating extensive repairs.

Visual inspections at Turkey Point 4, following plant shutdown in July 1982 to repair a small tube leak, revealed that the leak was caused by damage to a tube at the periphery of the tube bundle by a loose part. The inspection was conducted with a fiber optic device and included the entire periphery above the tubesheet and the tube lane region. The loose part, identified as a check valve pin from the feedwater bypass line, measured 1 in. x 2-1/4 in. Damage was also observed on other peripheral tubes in all three steam generators. All but one of these other tubes had previously been plugged. Some of these tubes had leaked before being plugged in 1977. In addition to the pin, numerous other foreign objects were found (e.g., bars, pieces of metal plate, bolts, wire, weld rod).

2.1.1.3 Value-Impact

Visual inspections as defined in Section 2.1.1.1 would result in initial inspections of all steam generators (SGs) plus inspections each time the secondary side is opened for modifications or repairs. Assuming an average of three steam

generators per plant, initial inspections of all steam generators during the next eddy-current test (ECT) outage, a remaining lifetime frequency of opening the secondary side of all of a plant's steam generators for maintenance or repairs of once per five years, and an occupational radiation exposure of 5 to 10 person-rem/inspection of one steam generator, the staff's consultant, SAI, estimates this action to result in an estimated occupational exposure of from 90 to 180 person-rem over an assumed 24-year average remaining life of the plant.

For plants where an upgrade of existing QA/QC work procedures is needed in order to effectively preclude the introduction of foreign objects into the steam generators, SAI estimates that implementation of these procedures could increase occupational exposures by 120 to 360 person-rem per plant over the assumed 24-year average remaining life of the plant. Thus, the total ORE attributable to implementation of these actions is estimated by the staff to be from 210 to 540 person-rem per plant. SAI estimates on avoided occupational exposures due to implementation of the subject visual inspections and improved QA work procedures conservatively account only for the avoided dose attributable to preventing ruptures in steam generator tubes and does not include avoided dose that accrues from preventing other types of damage, which must also be repaired, from loose parts. When the avoided SGTR dose of 83 person-rem is considered, the net estimated ORE attributable to these two requirements is an increase of from 127 to 457 person-rem over 24 years or about 5 to 19 person-rem per plant per year. It should be noted, however, that these numbers are considerably smaller than the avoided occupational exposures, 1060 person-rem (plant with medium degree of degradation) to 7500 person-rem (severely degraded plant), which can be achieved through implementation of effective secondary water chemistry and condenser inspection programs, which are discussed in Sections 2.5 and 2.6.

SAI estimates that the cost required to implement these two actions (about $0.2M per plant) is more than offset by the economic savings (> $3.1M) resulting from implementation. Therefore, the staff finds that economic cost does not bar implementation of these actions.

These actions could potentially reduce loose-parts-related SGTRs by as much as an estimated 90%. Since two of the four SGTRs to date have been loose-parts related, this translates to a 45% reduction in the overall SGTR frequency.

This reduction in SGTR frequency produces a corresponding reduction in the probabilities of core melt and significant non-core-melt releases. Using the criteria given in Table 3, these reductions correspond to a "low to medium" benefit in terms of reduced core-melt probability and a "high" benefit in terms of reduced probability of significant non-core-melt releases.

The following comments received from the SGOG (letter, August 25, 1983) were typical of many comments received from industry on this issue.

a. A one time visual inspection of the secondary side of a steam generator through exisiting access ports is a reasonable method for finding loose parts or foreign objects, providing the following points are recognized.

   (1) There are differences in steam generator geometry and access; therefore, the scope and type of visual inspection must be tailored to the specific steam generator design.

(2) Inspection should be balanced with awareness of the potential for tube corrosion when a steam generator is drained.

b. Subsequent visual inspections of the secondary sides of steam generators should be performed only when the specific situation warrants, e.g., when nondestructive examination suggests the presence of a foreign object or when QA/QC or cleanliness procedures employed during maintenance are judged to have been insufficient. When conducted, such a subsequent inspection should be restricted in scope and duration to the minimum required to resolve the specific question that prompted it.

Comments a.(1) and a.(2) above are considered to be consistent with the intent of the staff recommended actions. The staff also agrees in principle with SGOG's comment b. above; specifically, that followup inspections should be performed only when the specific situation warrants. The staff believes that the staff recommended actions are consistent with this goal, and are an acceptable approach to ensuring against loose-parts induced damage.

Consumers Power Company (letter, September 1, 1983) and Duke Power Company (letter, January 6, 1983) expressed concerns regarding the potential for corrosion while the steam generators are drained and the tube bundles are exposed to the atmosphere. Consumers Power Company stated that it experienced damage requiring extensive tube plugging during a "dry-layup" condition similar to what would exist during the proposed visual inspection, and that recent corrosion events at Oconee (following auxiliary feedwater system modifications) and Arkansas 1 underscore the apparent sensitivity of steam generators to air. Consumers Power also commented that work by the Electric Power Research Institute (EPRI) also supports avoidance of a dry, moist layup environment for steam generator tubes, and concluded that proper followup of eddy current indications which are indicative of potential tube wear as well as appropriate procedural controls and QA/QC is sufficient for the prevention and detection of loose parts.

The staff acknowledges the desirability for minimizing exposure of tube bundles to air. This is particularly important in cases where chemical species such as sulfur (which may be highly aggressive in the presence of oxygen even under ambient conditions) are present in the steam generator. Regardless of the circumstances under which the steam generator is being drained (e.g., for purposes of performing maintenance, repairs, modifications, and/or visual inspections), precautions must be taken to ensure that the potential for corrosion is minimized, and that the steam generators are restored to a wet layup condition as quickly as possible. The staff agrees that in certain cases, such as when significant amounts of sulfur are present (as was apparently the case at Arkansas 1), exposing the tube bundle to air may be inadvisable until appropriate remedial measures are taken.

Visual inspections consistent with the staff recommended actions should not result in significant increases in exposures of the secondary side to the atmosphere. The staff recommended actions involve a single baseline inspection of each steam generator, with followup inspections only if modifications or repairs are made to the SG internals (which typically occur only once every five years) or when ECT indicates evidence of loose-parts-induced damage. Wisconsin Electric Power Company, which has already performed such inspections, estimates approximately 2 days are required to inspect each steam generator (letter, August 10, 1983).

With appropriate precautions, and remedial measures if necessary, visual inspections in accordance with the staff recommended action are not expected to result in a significant detrimental impact on the steam generator tubes. However, because of concerns related to corrosion, some licensees may elect to implement alternatives to visual inspections, including installation and operation of a loose-parts-monitoring system as discussed in Section 2.1.4. Any such alternative approach should include criteria for determining when appropriate remedial measures should be taken to address any suspected presence of loose parts or foreign objects.

Duke Power Company also expressed the concern that visual inspections could themselves increase the potential for leaving foreign objects in the steam generators. The staff disagrees with this comment since the staff recommended actions also call for improved QA/QC procedures in addition to visual inspections to preclude the source of Duke Power Company's concern.

2.1.1.4 Conclusions

Given that two of the four SGTR events to date have been caused by damage caused by loose parts/foreign objects, effective licensee programs to prevent and detect loose parts/foreign objects are an important element of overall licensee programs intended to ensure the integrity of the steam generator tubes. The staff concludes that visual inspections and improved QA/QC work procedures, as identified in Section 2.1.1.1, would be effective measures for the prevention and detection of loose parts and foreign objects, and has therefore adopted these items as staff recommended actions. Apart from benefits in the areas of reduced SGTR frequency and the associated probabilities of core-melt and significant non-core-melt releases, the staff's value-impact analysis indicates that these actions will be cost effective. The net ORE impact of 127 to 457 person-rem per plant associated with these actions is more than offset by the estimated ORE reductions (1000 to 7500 person-rem) which can be achieved through implementation of effective secondary water chemistry and condenser inspection programs (Sections 2.5 and 2.6).

2.1.2 Loose-Parts-Monitoring Systems

In the event that loose parts or foreign objects are introduced into the steam generators, operation of a loose-parts-monitoring system (LPMS) will increase the probability of prompt detection. The staff considered as a potential industry action that all PWRs should install and operate an LPMS. Such a system should be capable of monitoring the steam generator primary and secondary sides, and should conform to Regulatory Guide 1.133. In addition, sufficient sensors should be provided in acoustically coupled regions of the steam generator to ensure adequate LPMS sensitivity for the detection of loose parts in the secondary side and in the channel head.

It is likely that of the two SGTRs experienced to date that were attributed to loose parts, either visual inspection after maintenance or improved QA accountability would have detected the causes of one of the SGTRs before it occurred and either visual inspection, QA, or LPMS would likely have detected the cause of the other SGTR before it occurred. SAI estimated a 70% effectiveness for implementation of an LPMS in detecting loose parts, compared to a 90% effectiveness for secondary-side visual inspections and QA accountability.

Given that two of the four SGTRs to date have been loose-parts related, visual inspections plus QA would be expected to reduce the overall baseline SGTR frequency by 45%. Implementation and operation of an LPMS would increase the amount of reduction to 48%. Thus, the incremental improvement that accrues from the addition of an LPMS, given the existence of inspection and QA accountability, is small.

The staff expanded on the SAI analysis to consider a range of effectiveness of 60% to 90% for steam generator visual inspection and QA/QC accountability and a range of 70% to 90% for LPMS.

Given the above ranges of effectiveness, the overall SGTR frequency is reduced between 30% and 45% by implementing visual inspections plus QA/QC. If, in addition an LPMS is implemented, the overall SGTR frequency is reduced between 44% and 50%. Given the implementation of visual inspections and QA/QC, the added reduction in the overall baseline SGTR frequency attributable to implementing an LPMS is between 3% and 18%. There would be a corresponding additional reduction in the probability of core-melt and significant non-core melt releases. Based upon the value-impact criteria defined in Table 3, implementation of an LPMS would provide an additional "low" benefit in terms of reduced probability of core melt, and an additional "medium" benefit in terms of reduced probability of significant non-core-melt releases. However, depending on the effectiveness of visual inspections and QA, this "medium" benefit in reducing the probability of significant non-core-melt releases may be only a small fraction of the corresponding benefits to be derived from visual inspections and QA/QC (Section 2.1.1) and from implementation of staff recommendations concerning improved secondary water chemistry control (Section 2.5) and condenser inspections (Section 2.6).

The net economic benefit of visual inspection plus quality assurance (QA/QC) is estimated by SAI at $2.9 million (M). The net economic benefit of visual inspection + QA/QC + LPMS was estimated to range from $2.2M to $2.6M where an LPMS must be installed. The net benefit of visual inspection + QA/QC + LPMS was estimated to range from $2.4M to $2.8M for plants having an acceptable LPMS.

The staff's consideration of a broader range of effectivenesses for the potential actions indicates a maximum net benefit of $1.9M from visual inspections + QA/QC, assuming these actions are 60% rather than 90% effective. Assuming a 90% effectiveness for an LPMS, the net cost benefit for visual inspection + QA/QC + LPMS is from $2.3M to $2.8M. Thus, for the range of parameters considered, the net cost saving attributable to an LPMS ranges between a negative $0.7M and a positive $0.9M.

The SAI study indicates that the ORE required to implement an LPMS (10 to 15 person-rem over plant life) is offset by the avoided ORE (6 person-rem over plant life). As with the economic impact, the staff has evaluated a broader range of possibilities, but has found that any net ORE savings would be minimal (maximum of 33 person-rem over an assumed 25-year remaining plant lifetime).

The SGOG stated that an LPMS should not be required on the secondary sides of steam generators because visual inspection, QA/QC and follow-up of ECT indications should be adequate and because signals from an LPMS currently available have proven difficult to interpret leading to difficulty in determining when action should be taken (letter, September 30, 1982). Wisconsin Public Service

Corporation (WPSC) stated that LPMSs have a low confidence level as illustrated by plant operating experience and are not reliable enough to justify purchase and installation (letter, October 4, 1982).

The SGOG comments on the necessity of an LPMS based on the adequacy of visual inspections + QA/QC are consistent with the staff's conclusions. The staff does not necessarily agree with the remaining SGOG comments and the WPSC comments because it is also apparent from operating experience that a properly designed, maintained, and operated LPMS can provide very useful information that can contribute to avoiding damage to a plant. However, the benefits do not include significant net ORE, risk, or other benefits not already accounted for by visual inspections + QA/QC.

Depending upon the effectiveness of visual inspections and QA/QC in preventing loose-parts-related failures, a secondary-side LPMS may provide only a small additional incremental reduction in SGTR frequency and in the probabilities of core-melt and significant non-core-melt releases. Any potential for net cost benefits is also dependent on the effectiveness of the visual inspections and improved QA/QC procedures. Future experience will indicate the actual effectiveness of the visual inspections and improved QA/QC work procedures and whether additional backup provisions, such as an LPMS, are necessary. Given the implementation of appropriate secondary-side visual inspections and improved QA/QC procedures, the staff concludes there is insufficient justification at this time to support implementation of a LPMS system as an additional staff recommended action. However, as discussed in Sections 2.1.1.1 and 2.1.1.3, some utilities may prefer to implement an LPMS in lieu of secondary-side visual inspections.

2.2 Inservice Inspection of Steam Generator Tubes

2.2.1 Supplemental Tube Inspections

2.2.1.1 Potential Industry Action

The current Standard Technical Specifications (STS) (NUREG-0103, NUREG-0212, and NUREG-0452) specify that inservice inspection of the steam generator tubes be performed at periodic intervals. The minimum required inspection sample is 3% of all SG tubes per plant. The results of this inspection sample are categorized as C-1, C-2, and C-3 depending on the severity of the results, with C-3 being the most severe. It was initially proposed that the definition of Category C-2 be revised to incorporate Categories C-2 and C-3 as presently defined in the STS. Specifically, Category C-2 would have been redefined to include inspection results where 1 or more tubes is found to be defective or where 5% or more of the tubes inspected are found to be degraded. The definition of Category C-1 would have remained unchanged.

For steam generators with Category C-1 results, no additional actions would have been required (unchanged from current STS). If steam generators with Category C-2 results were found, the following actions would have been required.

(1) In each steam generator where the results of the first sample inspection are Category C-2 (in accordance with the revised definition), additional tubes would be inspected. The sample would include either 100% of the remaining tubes in the steam generator, or a statistically based sample

which ensures with a probability of 0.95 that the number of defective tubes that could remain uninspected is less than the tolerable number of tube failures during design-basis accidents. Methods for determining these statistically based samples are detailed in NUREG/CR-1282. The tolerable number of tube failures would be determined by plant-specific analyses (a description of these analyses is provided in a draft NRC report, "Initial Staff Recommendations Stemming from Resolution of USIs Regarding Steam Generator Tube Integrity," which is enclosed with NRR memorandum, SECY 84-13 dated January 11, 1984). The statistical methods and systems analyses would be approved by the NRC before the results could be used to develop and implement a statistically based sampling inspection program.

(2) Supplemental sample inspections could be limited to a partial-length inspection of each tube, providing the inspection includes those portions of the tubes where imperfections were found during initial sampling.

(3) Notwithstanding any inspection rotation schedule, any additional steam generators not yet inspected during the current inspection shall be inspected in accordance with the requirements in the Steam Generator Tube Sample Selection and Testing portion of the Technical Specifications.

(4) Prompt notification of NRC, in accordance with the Technical Specifications, would be required.

Under the proposed potential industry action, the staff would have considered licensee proposals to change the Technical Specifications to permit supplemental sample inspections to be limited to subsets of tubes if it could be shown from previous inspection results or from unique design or phenomenological aspects that the degradation is limited to well-defined areas contained within these subsets of tubes.

Considering the results of the staff's value-impact analysis (described in Section 2.2.1.3), the staff has concluded that this potential industry action is not appropriate in its present form for inclusion as a staff recommended action. As discussed in Section 2.2.1.4, the staff will evaluate the supplemental tube inspection sampling issue as a staff action.

2.2.1.2 Basis for Initial Consideration

The current requirements for inservice inspection frequency and scope are based primarily on experience, engineering judgment, and practicality. The required frequency was based on the frequency of refueling outages so that regular ISI would not unnecessarily affect plant availability and incur needless expense. The required scope of ISIs also was established primarily on the basis of experience and judgment with the goal of achieving safe operation of steam generators by selecting a representative tube sample and minimizing personnel exposure. No analysis has been performed which included (1) a system and accident evaluation to establish the limiting number of defective tubes that can be tolerated to fail during design-basis accidents and (2) statistical determination of the required scope of inspection to ensure that no more than the limiting number of defective tubes will not be inspected. Under the current ISI requirements, a minimum 3% initial sample of the steam generator tubes must

be inspected. Although there is no theoretical basis for the initial 3% sample size, 3% inspection sampling in conjunction with primary to secondary leakage rate limits in the Technical Specifications have been generally successful in identifying the existence of tube degradation problems, and serving as a basis for determining whether additional sampling should be performed. This success has been due largely to the fact that the primary modes of degradation affecting operating steam generators are mechanistic in nature. They result either from adverse chemical conditions, improper mechanical design or materials selection, or a combination of these parameters. The result is that when such conditions occur, the degradation is not generally isolated but affects a large number of tubes. Thus, the initial 3% sample is sufficient to identify the steam generators which are experiencing general degradation. Because of this, the 3% inspection has also proved sufficient to determine if a steam generator tube leak was the result of an isolated incident or if it was the result of a significant mode of general degradation. Thus, the initial 3% inspection sample requirement would remain unchanged under this potential industry action.

The inspection results for the initial 3% sample are currently categorized in the STS as C-1, C-2, or C-3 depending upon the number of defective tubes (i.e., tubes with imperfections which exceed the plugging limit) and degraded tubes (i.e., tubes with imperfections greater than 20% of the tube wall thickness, but less than the plugging limit) found as described below:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

For results categorized as C-1, no additional sampling is required under the current STS. This would remain unchanged under the potential industry action.

For results categorized as C-2 (as currently defined in STS), the STS requires that an additional 6% sample (of the total number of SG tubes) be inspected. If the results of this additional sample are also categorized as C-2, then an additional 12% sample must be inspected. If the results of this third sample inspection are also categorized C-2, the current STS requires no additional sampling. The level of sampling required for Category C-2 has not been based on providing any specific statistical confidence level that requires that the number of uninspected tubes with flaws exceeding the plugging limit will be less than the maximum tolerable number of tube failures for postulated accident conditions.

To illustrate the limitations of the current requirement, one can consider a situation in which 1% of the SG tubes are defective, and that the defective tubes are uniformly distributed across the bundle. For a truly representative initial 3% sample, the inspection results categorization would be C-2 (as currently defined in the STS). If it is Category C-2, additional supplemental

samples ranging to a maximum additional 18% (6% + 12%) of the tube population would be inspected. Again, for a truly representative sample, the results of the supplemental inspection would also be STS Category C-2, and no additional sampling would be required. Under this situation, 1% of the remaining 79% of the tube population which was not inspected would be defective. This would amount to as many as 120 tubes (for a B&W steam generator) which would be defective but which would not be inspected.

Another limitation to be noted for this case is that under current requirements for C-2, the other steam generators would not have to be inspected. The STS permits the licensees to inspect the SGs on a rotating schedule, provided none of the SGs which are inspected are found to be Category C-3. Steam generators at a given plant often (but not always) behave in a similar manner. When one SG is found to be in Category C-2, it is reasonable to infer that the uninspected steam generators may be similarly degraded.

Under the potential industry action for Category C-2, the supplementary sample size would be either 100% of the remaining tubes or would be based on plant-specific analyses as discussed in Section 2.2.1.1. The inservice inspection program would also be extended to include the other steam generators, in the event that they are not already included in the inspection program. In addition, prompt notification of the NRC would be required if Category C-2 results are obtained.

For Category C-3 results (as presently defined in the STS), the current STS requires inspection of 100% of the tubes in the subject steam generator, extension of the inspection into the other steam generator(s), and prompt notification of the NRC. Under the potential industry action, Category C-3 results as currently defined in the STS would be redefined as Category C-2. However, the additional actions to be taken under the potential industry action for inspection results which are currently defined as Category C-3 would remain unchanged, except that a statistically based sampling plan could be employed in lieu of 100% inspection of the remaining tubes if justified by the statistical analyses and plant-specific systems analyses discussed in Section 2.2.1.1.

Having determined from the initial 3% sample that a steam generator is experiencing significant degradation, the intent of the potential industry action is to ensure that the number of uninspected tubes which may be defective is less than the tolerable number of tube failures during design-basis accidents. The tolerable number of tube failures would be based on (1) use of 10 CFR Part 100 to determine the maximum tolerable leak rate through failed steam generator tubes concurrent with a main steam line break (MSLB) outside containment, (2) use of the maximum containment design pressure limit to determine the maximum tolerable leak rate through failed steam generator tubes during an MSLB inside containment, and (3) use of the 2200°F peak cladding temperature limit established by 10 CFR 50.46 to determine the tolerable leak rate through failed steam generator tubes concurrent with a loss-of-coolant accident.

2.2.1.3 Value-Impact

Economic and ORE Value-Impact

The staff estimates the plant average total present worth costs to implement the potential industry action over an assumed remaining 24-year plant life to be as follows:

W:	$2,900,000
CE:	$3,540,000
B&W:	$8,260,000

The bases for these estimates are provided in Section 2.2.1.5. The difference in costs between the NSSS SG types reflects differences in the number of tubes per SG and the number of SGs per plant. These estimates assume that licensees would submit proposed changes to the Technical Specifications to permit supplemental inspections to be confined to subsets of tubes in which the degradation can be shown to be limited to these subsets. This assumption has reduced the estimated cost for implementing this action by approximately 50%.

These cost estimates are dominated by added costs resulting from extended outage times. These are plant average cost estimates. Depending on plant-specific circumstances, the implementation costs may be significantly higher at some plants. However, these costs do not consider steps that could be taken by utilities to shorten the necessary inspection times (e.g., development of multiple-probe inspection techniques and real-time ECT evaluation) since the feasibility of such steps have not been evaluated by the staff.

Based upon estimated avoided costs, the average cost benefit (impact) during the remaining plant life is as follows:

W:	$[1,600,000] to $2,500,000
CE:	$[2,240,000] to $1,860,000
B&W:	$[6,960,000] to $[2,860,000]

Note: Unbracketed figures represent net cost benefit (savings); bracketed figures represent net cost impact.

The average per year ORE is estimated as follows:

W:	5.2 person-rem
CE:	5.1 person-rem
B&W:	9.0 person-rem

These OREs are only partially offset by the estimated avoided ORE of from 1.3 to 6.3 person-rem. However, when compared to the average ORE for inspection, maintenance, and repairs of steam generators of about 150 person-rem as reported in NUREG-0886, the net ORE impacts are relatively small. On this basis, the staff concludes that ORE is not a major factor in this value-impact evaluation.

Potential Reduction in Core-Melt and Non-Core-Melt Release Probabilities

Based upon experience to date, the potential for reducing the baseline frequencies (Section 3) of tube rupture occurrences is estimated by SAI to be on the order of from 5% to 20%. This compares with an estimated 64% reduction from implementing the staff recommended actions for the prevention and detection of loose parts (Section 2.1), improved secondary water chemistry control (Section 2.5), and condenser ISI (Section 2.6). Assuming that these staff recommended actions are implemented, the percentage reduction in baseline frequency of rupture directly attributable to the potential industry action for supplemental inspection sampling may be no greater than 6%. This estimate is somewhat uncertain, but

does indicate a potential medium benefit (as defined in Table 3) in terms of reduced probability of significant but less than core-melt releases, but only a low benefit in terms of reduced probability of core melt.

These relatively low benefits reflect operating experience which has shown that when flaws escape detection during ISI sampling, the most likely consequence is a small leak. Allowable limits for primary to secondary leakage have been established in the plant Technical Specifications beyond which the plant must be shut down for appropriate corrective action, thus minimizing the potential for tube ruptures during normal and postulated accident conditions. It should be noted that the staff recommended action for PWRs to adopt the leak rate limits specified in the Standard Technical Specifications (Section 2.8) would provide added assurance of adequate tube integrity.

Industry Comments

This potential industry action was commented on extensively by industry. The industry comments were generally negative, both as to the need for this potential action and as to potential costs and ORE impacts.

Comments received from SGOG (letter, August 25, 1983) were generally representative of comments received from other industry representatives. Some of the major points made by SGOG included the following:

(a) While a 3% random sample is a reasonable, proven starting point for eddy current inspection of a steam generator, immediate escalation to inspection of all the tubes in the steam generator upon finding a single defective tube (or five percent degraded tubes) and inspection of all other steam generators are unwarranted and undesirable.

- The current step-wise progression from 3% to an intermediate sized sample before launching a 100% inspection has ensured that steam generators with higher levels of degradation have been inspected completely while those with isolated instances of tube degradation have been able to avoid unnecessary additional costs and radiation exposure of 100% inspections.

- Utilities fully understand the need for adequate eddy current inspections and will continue to perform them; however, the requirement that all tubes be inspected if one in a sample is found to be defective may provide a disincentive to inspect more than the minimum sample size.

- If eddy current inspection requirements are revised despite the lack of demonstrated need, the revised requirements should retain an intermediate step between the initial sample and inspection of 100% of the tubes.

(b) The need to inspect all other uninspected steam generators should be evaluated on a case by case basis. When a mode of tube degradation can be isolated to a single steam generator, costly and lengthy inspections of other steam generators are unnecessary.

(c) The cost estimates used in assessing the impact of the proposed actions appear to be low and unrealistic. They assume that the inspection can be performed off the critical path with no cost for replacement power. Additional unscheduled inspections will likely be in the critical path and replacement power would be required. The cost of eddy current inspection, including replacement power costs, may easily reach $500,000 to $800,000 per day. [Babcock & Wilcox (letter, February 10, 1983) and Duke Power Company (letter, January 6, 1983) noted that the impact on critical path outage time during unscheduled shutdowns to repair SG leakage would be particularly severe for plants with Babcock & Wilcox steam generators due to their large number of tubes.]

(d) Occupational radiation exposure due to performing steam generator eddy current inspections under existing requirements has been reported (NUREG/CR-1490) to be between 5 and 20 person-rem per steam generator. Occupational radiation exposure could be expected to increase substantially under the proposed requirements.

(e) Since inspection requirements and criteria will be defined, prompt notification of the NRC of results should not be required.

These comments and other similar comments from industry were considered in the staff's disposition of this potential industry action. Regarding comment (c) above, the staff acknowledges that consideration of additional outage time associated with this potential industry action was not included in the SAI value-impact analysis which was provided to industry for its review and comment. As discussed in Section 2.2.1.5, the cost estimates herein do consider the potential for increases in outage time for Westinghouse, Combustion Engineering, and Babcock & Wilcox steam generators, respectively. Regarding comment d) above, the staff estimates of occupational exposures (see Section 2.2.1.5) are consistent with NUREG/CR-1490.

2.2.1.4 Conclusions

Licensees should be aware of limitations of present supplemental inspection sampling requirements in the Technical Specification in cases where Category C-2 results are obtained during initial sampling. In such cases, licensees should carefully consider the need for additional inspections beyond minimum Technical Specification requirements as may be determined necessary to ensure that uninspected tubes will not be subject to rupture during normal operating or postulated accident conditions.

The limitation of the current requirements notwithstanding, the potential for further reducing the baseline SGTR frequency, and thus the probabilities of core-melt and significant non-core-melt releases, appears to be relatively small compared to the reductions that can be achieved through the implementation of visual inspection and QA for loose parts (Section 2.1), improved secondary water chemistry (Section 2.5), and condenser inservice inspection (Section 2.6). Considering this and possibly significant net cost impacts, the staff concludes that the potential industry action as described in Section 2.2.1.1 is not appropriate for inclusion as a staff recommended action.

As discussed in Section 4.2.4, the staff will undertake further evaluation of the supplemental tube inspection sampling issue as a staff action. This effort will investigate the need for alternative, more practical actions to upgrade the existing Technical Specification requirements pertaining to this issue which could be implemented on a case-by-basis as needed.

2.2.1.5 Cost and ORE Value-Impact Assumptions

This section describes the basis for the staff's cost and ORE value-impact evaluation for the potential industry action concerning supplemental tube inspections (Section 2.2.1.1). The staff's evaluation is based largely on the SAI unit cost and ORE estimates (letter, February 25, 1983 and SAI report, "Value-Impact Analysis").

The following assumptions were employed:

(1) Westinghouse (W) steam generators: 3300 tubes/SG, 4 loops
Combustion Engineering (CE) steam generators: 8500 tubes/SG, 2 loops
Babcock and Wilcox (B&W) steam generators: 15,500 tubes/SG, 2 loops

(2) The cost estimates herein assume a concurrent inspection of two steam generators. For W plants, the four SGs have been idealized as two SGs, with 6600 tubes/SG.

(3) For a given inspection, the staff assumed a 0.4 probability that one or more steam generators will be Category C-2 (as defined in current STS) based on an informal staff survey of plant data.

(4) Given that one SG is C-2, the other SG was assumed to have 0.5 probability of also being C-2.

(5) Given that an SG is C-2, the probability of having to perform 100% (or close to 100%) inspection of the SG tubes was assumed to be 0.5. This is a highly judgmental estimate. It assumes that licensees would propose amendments to Technical Specifications to permit the supplemental inspections to be limited to subsets of tubes in cases where it can be shown that the degradation is limited to well-defined groups of tubes because of unique design or phenomenological aspects. The effect of this assumption is to reduce the estimated costs for implementing this potential requirement by approximately half. Although not directly considered, the probability of performing 100% inspections could also be influenced by the use of statistically based sample sizes based upon the tolerable number of tube failures.

(6) Additional costs for 100% inspection were computed relative to cost of inspecting 21% of the tubes per the current requirement.

(7) It is assumed that tubes will be inspected at a rate of 36 tubes/hr/SG. This considers that 20% of the tubes will be inspected full length at 20 tubes/hr and 80% of the tubes over a partial length at 40 tubes/hr (see page 68 of the SAI report).

(8) From page 68 of the SAI report, ECT inspection costs are estimated to be $22,000/day for parallel inspection of two SGs with 4 crews in 10-hour shifts. Inspection costs are estimated to be $15,000/day for inspection of one SG with 2 crews in 10-hour shifts.

(9) Additional ORE is estimated to be 5 person-rem for each additional SG entry (2 additional entries assumed for W, 1 additional entry assumed for B&W and CE) plus 2×10^{-3} person-rem for each additional tube inspected (page 37 of the SAI report).

(10) The staff estimates that in 80% of the cases in which at least one SG at a plant is found to be Category C-2, the licensees are already inspecting all SGs. This estimate is based upon an informal staff survey of plant data.

Based on the above, the annual costs and ORE to implement the potential industry action are estimated to be as follows:

W:	$34,000	4.6 person-rem
CE:	$40,000	4.5 person-rem
B&W:	$68,000	8.0 person-rem

To the above costs must be added the costs of substitute power (during scheduled outages) or replacement power (during unscheduled outages) in the event that the potential action results in an extended outage. SAI estimates a range in cost difference for substitute power from $0 to $15/MW-hr or $0 to $360,000/day, assuming that the utility can meet the demand with power from another of its nuclear or coal plants (letter, February 25, 1983). If oil-fired plants are used, the cost difference is estimated to range from $25 to $45/MW-hr (Ibid). The cost estimates given here are based upon an average cost difference of $360,000/day for substitute power.

The additional time necessary to perform the proposed additional supplemental inspections is estimated to be 7.5, 9.4, and 17 days for W, CE, and B&W plants, respectively. If the scheduled outage time is extended by the additional time required to perform the additional supplemental inspections, then the cost for substitute power is estimated to be $2.7M for W, $3.4M for CE, and $6.15M for B&W. The additional annual cost for substitute power is determined by multiplying these costs by 0.4 (probability of being C-2) times the probability that the outage would be extended. SAI has estimated this latter probability to be between 0.1 and 0.2 considering the range in durations of refueling outages (Ibid). The SAI estimate was based upon 16 additional days being required to perform the inspections. Considering the staff estimates of additional inspection time (i.e., 7.5, 9.4, and 17 days for W, CE, and B&W, respectively), the staff assumed a 0.1 probability for W and CE plants and a 0.2 probability for B&W plants that the potential requirement will result in an outage extension. Thus, the annual cost of substitute power is estimated to be as follows:

W:	$54,000
CE:	$68,000
B&W:	$245,000

Thus, the annual total cost to implement the potential action during scheduled outages is as follows:

W:	$88,000
CE:	$108,000
B&W:	$314,800

If a plant is forced to shut down as a result of exceeding the Technical Specification primary to secondary leakage rate limit, an unscheduled SG inspection is required. The industrywide average probability for SG-related forced shutdowns is 0.188 per year (SAI report). Implementation of the secondary water chemistry and condenser inspection recommendations (Sections 2.5 and 2.6) would be expected to reduce this frequency by an additional 32%. The probability that one or more steam generators will be categorized as C-2 is again assumed to be 0.4. If C-2, the probability of having to perform 100% inspection is again assumed to be 0.5. Cost of replacement power, assuming the outage is extended, is estimated to be $475,000/day. On this basis, the plant's average annual costs and ORE to implement the potential industry action during unscheduled outages are as follows:

W:	$91,000	0.6 person-rem
CE:	$119,000	0.6 person-rem
B&W:	$215,000	1 person-rem

The total present worth costs to implement this potential action over an assumed 24-year remaining plant lifetime is obtained by increasing the "annual" figures (for scheduled and unscheduled outages) by a factor of 15.6 (letter, February 25, 1983) as follows:

W:	$2,900,000
CE:	$3,540,000
B&W:	$8,260,000

Present worth of avoided costs are estimated by SAI to be $1.3M to $5.4M. Thus, the present worth of the net savings (or costs) over a 24-year remaining plant lifetime is as follows:

W:	$(1,600,000) to $2,500,000
CE:	$(2,240,000) to $1,860,000
B&W:	$(6,960,000) to $(2,860,000)

2.2.2 Full-Length Tube Inspection

As discussed below, the potential industry action concerning full length tube inspections has been dispositioned as a staff recommended action.

2.2.2.1 Staff Recommended Action

The Standard Technical Specifications (STS) and Regulatory Guide 1.83, Part C.2.f, currently define a U-tube inspection as meaning an inspection of the steam generator tube from the point of entry on the hot-leg side completely around the U-bend to the top support of the cold-leg side. The staff recommends that tube inspections should include an inspection of the entire length of the tube (tube end to tube end) including the hot-leg side, U-bend, and cold-leg side.

This recommendation does not mean that the hot-leg inspection sample and the cold-leg inspection sample should necessarily involve the same tubes. That is, it does not preclude making separate entries from the hot- and cold-leg sides and selecting different tubes on the hot- and cold-leg sides to meet the minimum sampling requirements for inspection.

Consistent with the current STS requirement, supplemental sample inspections (after the initial 3% sample) under this staff recommended action may be limited to a partial length inspection provided the inspection includes those portions of the tube length where degradation was found during the initial sampling.

2.2.2.2 Basis for Initial Consideration

This recommended action involves a modified definition of a tube inspection such that the cold-leg side of the tubes from the upper tube support down to the tube outlet should also be included in the inspections. The basis for including the cold-leg sides of the tubes in the inspection is that operating experience has shown that the cold-leg side is also susceptible to a variety of degradation mechanisms (e.g., wastage, pitting, denting, and fretting-induced wear).

A substantial fraction of PWR licensees currently recognize the importance of cold-leg tube inspections since approximately 70% to 80% of the plants with U-tube-type steam generators are currently subjected to at least some cold-leg inspection during inservice inspections. Degradation (pitting attack) on the cold-leg side has been observed in hundreds of tubes at Indian Point 3 (meeting summary, September 28, 1982) and Millstone 2 (letter, March 5, 1982). Prairie Island 2 (NUREG-0886), Salem 1, and Zion 1 have recently experienced cold-leg corrosion-thinning degradation. New Westinghouse Model D steam generators experienced an early generic tube vibration problem in the preheater section on the cold-leg side which could potentially cause accelerated wear on the tubes at the baffle supports. Examples of forced shutdowns as a result of cold-leg leakage include Indian Point 3 and Ringhals 3 in the fall of 1981.

2.2.2.3 Value-Impact

In general, it will be possible to inspect the full length of tubing from either the hot- or cold-leg side. The staff estimates that a single-entry full length inspection of a 3% sample of tubes will increase ORE by 0.4 to 1.0 person-rem per plant per annum. This compares with avoided annual ORE of 0.3 and 3 person-rem for assumed reductions in forced outage frequency of 1% and 10%.

For approximately the inner five rows of tubes with small-radius U-bends, it will not be possible to insert a standard full-sized probe through the U-bend to the opposite leg. Smaller diameter probes can be used to inspect the inner row tubes on the opposite leg, but with some loss of sensitivity. Should circumstances arise where additional test sensitivity is needed for these tubes, special-purpose probes (e.g., probes utilizing surface riding coils) can be used. Alternatively, the licensee may elect to make a separate entry into the opposite leg to inspect with a full-sized standard probe. The licensee may also elect to make a separate entry into the opposite leg in cases where the results of the first sample inspection indicate that degradation on the opposite leg is confined to elevations below, say, the first support. A separate entry inspection will increase ORE by 1.6 to 12 person-rem.

The staff finds that separate entry inspections should generally not be necessary except perhaps in cases where degradation is found to be active in both legs. This being the case, licensees would eventually find it necessary to inspect the cold leg (as a result of leaks or ruptures), regardless of whether such inspections were a requirement. The staff concludes, therefore, that the staff recommendation for full length inspections by all PWR licensees will have little net effect on ORE.

The economic costs of cold-leg-side inspections ($140,000 to $234,000 over the remaining plant lifetime), even if performed from entries on the cold-leg side, are more than offset by the benefits ($300,000) for even a 1% reduction in forced outage frequency. Therefore, cost does not appear to be a significant factor in this value-impact evaluation.

None of the four SGTR events to date has involved the cold-leg side. However, it is difficult to quantify the potential reduction in SGTR frequency associated with implementation of cold leg inspections, since 70% to 80% of Westinghouse and Combustion Engineering licensees already perform cold-leg inspections to some degree. Considering that the staff recommended actions pertaining to the prevention and detection of loose parts and foreign objects (Section 2.1) and improved secondary water chemistry and condenser inspection programs (Sections 2.5 and 2.6) are estimated together to produce about a 64% reduction in the baseline SGTR frequency, the staff has considered that implementation of full-length inspections would most likely provide an additional reduction in the range of 1% to 10% where such inspections are not now being implemented. This corresponds to a low benefit (as defined in Table 3) in terms of reduced probability of core melt and to a medium benefit in terms of reduced probability of significant non-core-melt releases.

SGOG commented (letter, September 30, 1982) that inspection of cold-leg tubes is justified as noted by NRC; however, the scope should be flexible. Inspections should be plant specific with the extent and frequency based on each plant's history and experience with degradation in the cold leg. SGOG also commented that the hot-leg and cold-leg inspections should not have to be performed on the same tubes. The staff's recommendation on full-length tube inspections is consistent with these comments.

Alabama Power Company commented that it supports the inspection of tubes through the entire tube length (letter, January 11, 1983). TVA proposed that the first cold-leg inspection be considered a baseline inspection and not be used to classify the results of the general inspection. Tube degradation detected during the first inspection would be addressed by taking subsets to bound the affected tubes (letter, October 13, 1982). With respect to the TVA comment, the staff notes that extensive degradation problems have occurred on both the hot and cold legs. Thus, the staff believes that the cold leg should be inspected in the same manner as the hot leg.

2.2.2.4 Conclusions

Considering the effectiveness of cold-leg inspections in minimizing the potential for tube ruptures, a potential medium reduction in significant non-core melt releases, and the small change in ORE and absence of any significant cost impact, the staff concludes that full-length tube inspections are justified as a staff

recommended action for all PWRs with U-tube steam generators. This recommendation addresses an obvious limitation of the current ISI requirement and is already being implemented to varying degrees by much of the industry.

2.2.3 Denting Inspections

2.2.3.1 Potential Industry Action

Because denting has occurred in a number of steam generators, a proposal was developed to include criteria for denting inspections in all PWR Technical Specifications.

2.2.3.2 Basis for Initial Consideration

The basis for initial consideration of this potential industry action was that operating experience has shown that surveillance of tube denting is necessary to preclude leakage from stress corrosion cracking caused by denting. There has been one instance (Surry Unit 2 in 1976) in which denting led to high stress in the tube U-bend region resulting in an SGTR. Plant-specific criteria have been established for plants with extensive denting; however, generic or standardized criteria have not been developed. Generic implementation of this potential industry action would ensure that effective criteria for denting are implemented for all plants.

2.2.3.3 Value-Impact

On the basis of its review of the SAI analysis, the staff finds that the ORE and economic impacts are offset by the avoided ORE and costs, and, thus, ORE and economic costs are not major factors. Denting is a small to moderate contributor to the frequency of leakage (14 out of 140) and the largest single contributor (31%) to tube plugging rates. Although denting led directly to the tube rupture event at Surry 2, the potential for future occurrences of this type have been significantly reduced. This is because the precursor conditions that led to the Surry rupture are generally well understood, and licensees would be expected to recognize these conditions and to take appropriate corrective action in a timely manner (see Section 2.4.3). In addition, plant-specific denting criteria have been established for plants that have experienced extensive denting. Thus, the benefit of this potential industry action as a generic requirement may be relatively low in terms of reduced frequency of rupture and of significant releases compared with other potential industry actions considered by the staff.

The SGOG commented (letter, September 30, 1982) that inspection for denting is justified; however, (1) denting inspection requirements do not belong in the Technical Specifications and (2) the requirements proposed are too broad. The scope of inspection should really be based on the progression of denting. If denting has been arrested, a widespread inspection upon finding a few dented tubes is not warranted. TVA commented (letter, October 13, 1982) that denting inspections should be performed only on those tubes that would not allow passage of the standard ECT probe. Alabama Power Company commented (letter, January 11, 1983) that it supports some type of inspection for denting but that further evaluation is necessary before criteria are issued to licensees.

2.2.3.4 Conclusions

Generic implementation of generic denting criteria would not be expected to result in a significant reduction in SGTR frequency, core melt risk, or in the probability of significant non-core melt releases. However, as is discussed further in Section 4.2.2, the availability of generic denting criteria could result in a net cost savings to the NRC in terms of future review effort. Therefore, the staff will undertake further study and development of generic denting criteria as a staff action as discussed in Section 4.2.2.

2.2.4 Steam Generator Inservice Inspection Interval

As discussed below, the potential industry action concerning steam generator inservice inspection intervals has been dispositioned as a staff recommended action.

2.2.4.1 Staff Recommended Action

The maximum allowable time between eddy current inspections of an individual steam generator should be limited in a manner consistent with Section 4.4.5.3 of the Standard Technical Specifications and, in addition, should not extend beyond 72 calendar months.

2.2.4.2 Basis for Initial Consideration

The current Standard Technical Specifications (STS) and many plant Technical Specifications allow the regularly scheduled inspections to be limited to one steam generator on a rotating schedule if the results of the previous inspections indicate that all steam generators are performing in a like manner. The current STS inservice inspection frequencies require inspections at intervals from 12 to 24 months which may be extended up to 40 months if two consecutive inspections result in all inspection results falling into the C-1 Category or if two consecutive inspections indicate that previously observed degradation has not continued and no additional degradation has occurred.

For two-, three-, and four-loop plants, this could result in an interval of 80, 120, and 160 months, respectively, between required inspections on an individual steam generator. Operating experience indicates that steam generators at a given facility do not necessarily perform alike, and thus inspection results for one steam generator are not necessarily representative of the condition of each other steam generator. Although the steam generators may be performing in a like manner for some period of time following initial startup of the plant, new degradation mechanisms may develop that affect the steam generators in a non-uniform manner. To make the maximum allowed operating interval more consistent with actual degradation rates that have been observed in the field, the staff initially proposed that the maximum interval be limited to 48 months. This was subsequently increased to 72 months as discussed below.

2.2.4.3 Value-Impact

SAI estimates on the basis of plant data that steam generator inspection intervals average between 24 and 36 months and that implementation of a 48-month maximum limit on inspection intervals would impact only a few plants, approximately 5%. Beyond an initial adjustment of inspection intervals that might be

necessary at a few plants, generic implementation of this action would have a very small effect on the number of inspections being performed. SAI concludes, therefore, that although it is difficult to assess the exact cost and occupational exposure impacts and benefits associated with this potential industry action, they appear to be quite small.

After further evaluation, the staff has concluded that a 72-month maximum inspection interval would be consistent with the initial objective of precluding excessively long inspection intervals ranging up to 160 months and would further reduce potential cost or occupational exposure impacts.

The potential reduction in the baseline SGTR frequency, given generic implementation of this recommended action, was not specifically quantified by SAI, but is believed to be small relative to the potential reductions associated with the staff recommended actions for prevention and detection of loose parts and foreign objects (Section 2.1) and improved secondary water chemistry control and condenser inspections (Sections 2.5 and 2.6).

Industry comments generally supported a maximum 72-month inspection interval. SGOG commented there is general agreement with the proposed change to the maximum inspection interval (letter, August 25, 1983).

2.2.4.4 Conclusions

A maximum 72 month inspection interval per steam generator reflects accumulated operating experience, is consistent with good engineering judgment regarding the need for periodic inspections as part of an effective program to ensure steam generator tube integrity, and involves minimal adverse impacts; thus, it has been incorporated as a staff recommended action.

2.2.5 Inspections Following Shutdown for Repair of Leakage

2.2.5.1 Potential Industry Action

The current STS and many plant Technical Specifications do not require that unscheduled inspections be performed in the event of tube leakage unless the leak rate exceeds the allowable leak rate limits in the plant Technical Specifications. A proposal was made that this should be changed so that unscheduled inspections pursuant to the Technical Specifications should be conducted if the plant is shut down to repair a primary-to-secondary tube leak, regardless of whether or not it exceeds the Technical Specification leakage rate.

2.2.5.2 Basis for Initial Consideration

The current provisions of the Technical Specifications allow plants experiencing tube leakage below the limit to shut down, repair the leak, and return to service without conducting further inspections. The concern prompting consideration of this potential industry action was that since the occurrence of leaks during service may be indicative of new phenomena or accelerated rates of degradation, the corrective action to be taken upon shutdown should include tube inspections in addition to plugging the leaking tubes.

2.2.5.3 Value-Impact

SAI estimated that a generic requirement incorporating the subject potential industry action would result in a 17% increase in the number of required inservice tube inspections. ORE resulting from tube inspections would likewise increase by 17%. Economic costs would exceed 17% since a fraction of such required inspections will be in response to forced outages and the inspection will extend the required outage period. SAI estimates that the leakage tests performed as an industry practice to identify leaking tubes can usually be performed in one day; a complete ECT inspection requires 3.5 days. The additional 2.5 days would result in considerable cost (replacement power of $1.8M) whenever the inspection is on the critical path to plant restart. Accordingly, it would appear that this change has the potential to eliminate incentives for licensees to shut down to repair tubes that leak at less than the Technical Specification limits. SAI could not estimate potential averted costs and ORE associated with this potential action.

The staff finds that the net increase in the number of inspections as a result of uniform implementation of this potential action would be significantly less than 17% since licensees usually elect to perform some level of tube inspection, even when the leak rate limit has not been exceeded prior to plant shutdown. This would tend to reduce not only the net increase in cost and ORE associated with uniform implementation of the subject potential action, but also the potential benefits in the areas of averted cost and ORE.

Tube inspections during unscheduled plant outages to repair steam generator tube leaks serve to minimize the potential for tube rupture. Indeed as previously noted, licensees usually elect to inspect tubes during unscheduled outages to repair tube leakage, although tube sample sizes are sometimes less than what is called for by the subject potential industry action. Even if not inspected at that time, the steam generators would eventually be inspected anyway, pursuant to current requirements, at the next scheduled inspection. SAI estimates that steam generator inspection intervals average 24 to 36 months, and do not extend beyond 48 months in the vast majority (95%) of the cases. In addition, operating limits on allowable primary to secondary leakage (see Section 2.8) minimize the potential for SGTRs during the interim period prior to the next scheduled inspection. SAI could not quantify the expected reduction in SGTR frequency associated with generic implementation of this potential action; however, the staff believes the potential benefit to be relatively small compared to the potential benefits associated with the staff recommended actions for prevention and detection of loose parts and foreign objects (Section 2.1) and improved secondary water chemistry and condenser inspections (Sections 2.5 and 2.6).

SGOG stated (letter dated September 30, 1982) that full-scale ECT inspections should not automatically be required during an outage to repair any leak on the bases that (1) outages to repair tube leaks are all critical path time, and requiring a full-scale ECT during these outages penalizes a utility for conservative operating practice; (2) if the leak is associated with known generic degradation, extensive inspection is not necessary; and (3) if the leak is not associated with a known generic type of degradation, a minimum inspection should focus on whether other tube leaks are imminent. Similar comments were received from other industry sources.

2.2.5.4 Conclusions

In consideration of the fact that (1) tube inspections are usually performed by industry during unscheduled shutdowns, even in cases where the Technical Specification leak rate limit has not been exceeded, (2) generic and uniform implementation of the subject potential action would not be expected to result in any significant further reductions in the industry baseline SGTR frequency, and (3) potential cost and ORE benefits impacts could not be quantified, the staff concludes that the subject potential industry action should not be included as generic staff recommendation. The staff does believe, however, that licensees should continue to take appropriate action not only to repair observed leakage, but also any additional actions including inspections as needed to provide assurance that non-leaking tubes will not rupture before the next scheduled outage. In cases where the leak rate limits have not been exceeded, licensees should consider such factors as the nature of the degradation mechanism involved, "leak-before-break" characteristics associated with subject degradation mechanism, and the planned date for the next scheduled inspection in determining the need for an unscheduled inspection. "Leak-before-break" characteristics refers to the potential for the subject degradation mode to lead to tube rupture during normal or postulated accident conditions.

2.3 Improved Eddy-Current-Test Techniques

2.3.1 Potential Industry Action

To ensure that all licensees use appropriate methods and equipment in conducting eddy current tube inspections, a proposal was made for licensees to include several such practices in their eddy current test (ECT) program as follows:

(1) Eddy-current testing techniques or data evaluation techniques which are capable of eliminating tube support plate, tube sheet, denting, or other similar unwanted signal interferences and capable of discriminating among multiple defects shall be used.

(2) Eddy-current probes that can perform both absolute and differential coil inspections shall be used. Separate probes may be used to implement this dual capability.

(3) Eddy-current data from both the differential and absolute channels shall be evaluated as part of the overall data evaluation program.

(4) In addition to the calibration standards required by Article IV-3200 of Section XI of the Boiler and Pressure Vessel Code of the American Society of Mechanical Engineers (ASME Code), a standard shall be used with simulated wear or fretting-type flaws to ensure a conservative interpretation of signals for which fretting or wear may represent a possible source of signals. Typical examples include absolute signals over a significant axial length of the tube, absolute signals for which there has been little or no corresponding differential signal, and signals that can reasonably be inferred as possible fretting or wear flaws on the basis of experience (e.g., indications at the tube-to-baffle-plate intersections in the preheater sections of Westinghouse Model D steam generators). The simulated flaws shall be sufficiently tapered and smooth so that they produce little or no differential signal.

2.3.2 Basis for Initial Consideration

This potential industry action was proposed with the objective of improving the reliability and accuracy of ECT programs for purposes of detecting degradation in tubes. Regarding item (1) of the proposed industry action, laboratory experiments, and field experience have demonstrated the superiority of multiple-frequency ECT and other techniques to discriminate defect signals from background noise or interference signals. Sources of background noise include structural supports, tube diameter or geometry variation, and conductive deposits on the tubes. Multi-frequency or other equivalent techniques are essential to screen out these interference signals and thus permit accurate evaluation of the condition of steam generator tubing.

Regarding items (2), (3), and (4) of the potential industry action, eddy-current inspections, defect detection, and interpretation capabilities can be enhanced through the use of absolute mode inspections in addition to differential mode inspections. A wall-thinning flaw that is gradually tapered at its edges, as may be the case for fretting-type wear defects, may not produce a detectable signal on the differential channels. Such a fretting-type wear flaw will generally produce a signal on the absolute channels. A tapered, localized radial fretting or wear standard, as opposed to the hole standards specified in the ASME Code, may be necessary to correctly interpret the amplitude of the signal.

The tube that ruptured at Ginna in January 1982 as a result of a long fretting wear defect had been inspected in April 1981 by both the differential and absolute modes. This tube exhibited no differential signal in April 1981 but did exhibit an absolute signal approximately 5 inches long, which was not recorded at that time. This April 1981 signal can be interpreted as less than a 20% indication using the calibration hole standard as specified in Section XI of the ASME Code. However, this signal can be interpreted as a slightly greater than 40% indication if a fretting or wear calibration standard is used, which is greater than the 40% plugging limit for Ginna. An evaluation of the absolute signal in April 1981 using a fretting or wear standard may have resulted in the tube being plugged before the wear had proceeded sufficiently through the tube wall to cause the rupture.

Eddy-current testing has advanced significantly in recent years. Several aspects of this potential industry action, namely multifrequency ECT and use of absolute and differential mode inspections are already in widespread industry use. In addition, the industry has developed advanced technology, including specialized eddy-current probes and data evaluation techniques, that have been used at numerous plants in response to specific tube degradation problems that have challenged the detection capabilities of conventional ECT techniques.

2.3.3 Value-Impact

The SAI analysis indicated that the ORE and economic impacts are small and are more than offset by positive ORE and economic benefits. As discussed above, improved ECT procedures could potentially have averted one of the four steam generator tube rupture events to date; namely the tube rupture event at Ginna. Thus, the staff estimates that improved ECT techniques could potentially reduce the probability of rupture by up to 25% if implemented as a stand-alone action. Implementation of the staff recommended actions identified in Sections 2.1,

2.5, and 2.6 is expected to reduce the frequency of ruptures by a total of 64% as an industry average. Therefore, the additional potential incremental reduction in rupture frequency from improved ECT techniques is about 10%. Thus, improved ECT techniques are considered to have medium potential (as defined in Table 3) for reducing the probability of significant but less-than-core-melt releases.

SGOG stated the following (letter, September 30, 1982): ECT techniques to be applied to specific steam generators should be established in plant-specific programs prepared by utilities and submitted to NRC rather than through generic requirements uniformly applied. The factors that determine the proper ECT technique for a specific application are plant and sometimes steam generator specific. ECT is currently evolving. It is undesirable to require licensees to use more complex techniques than are necessary or to discourage experiments with new techniques as they are developed. SGOG also stated that use of a new "wear standard" should not be required. Special standards, where warranted, should be handled by plant-specific submittals. Development of new generic standards should be the result of actions by the appropriate ASME Section XI Code Committee.

Tennessee Valley Authority (TVA) recommended deletion of the portion of the ECT techniques proposal addressing the provision of ECT probes to provide the capability to perform both absolute and differential coil inspections (letter, October 13, 1982). TVA based its recommendation on its finding that the proposed actions should address the capability of the inspection system to detect types of defects but should not specify the method or technique to be used since a number of different techniques now exist and others will probably be developed in the future which may constitute an advancement in NDE techniques.

These comments are representative of comments received from other industry sources.

2.3.4 Conclusions

Use of appropriate ECT techniques as needed to detect defective tubes is a key element of an effective program for ensuring steam generator tube integrity. As noted by the SGOG, however, the factors that determine the appropriate ECT technique to be employed are often case-specific depending upon such factors as defect volume, orientation, and location and the presence of noise. Therefore, licensees should be aware of the limitations of the techniques they are employing such that more sensitive techniques are utilized as necessary in response to specific problems.

The staff has concluded that additional consideration of improved ECT techniques as a generic issue is warranted, but as suggested by the SGOG, this effort should be performed in parallel with ongoing ASME Code Committee activities to develop updated ECT procedures for incorporation into the ASME Code Section V for NDE and Section XI for ISI. Therefore, the staff has dispositioned the improved ECT issue as a staff action item which is addressed in Section 4.2.3.

2.4 Upper Inspection Ports

2.4.1 Potential Industry Action

A proposal was made that for all PWR applicants, upper inspection ports should be installed before issuance of an operating license so that the upper support plates and inner row U-bend tubes can be visually inspected. Operating plants were not included within the scope of this potential industry action based on a consideration of the ORE and economic impacts of installing ports in an operating plant's steam generator.

2.4.2 Basis for Initial Consideration

A primary motivation for initial consideration of this potential industry action is that upper inspection ports provide a direct means for monitoring the state of deformation in the upper support plate which is caused by the buildup of a hard corrosion product (magnitude) in the annular regions between the support plate and tubes. This buildup of corrosion product is generally referred to as denting (NUREG-0886). As denting becomes more advanced, it causes rectangular flow slots in the support plate, located between the legs of the inner row tube U-bends, to deform into an hourglass shape. This "hourglassing" in turn causes the legs of the inner row tube U-bends to displace toward each other, thereby leading to increased tube stress at the apex of the U-bend. This increased stress creates the potential for stress corrosion cracking and ultimately rupture of the inner row tubes. This mechanism was the cause of the SGTR event at Surry Unit 2 in 1976.

Steam generators are generally equipped with inspection ports located between the tube sheet and lower (first) support plate. These existing inspection ports provide only limited means for monitoring deformation of the upper support plate, including hourglassing of the upper support plate flow slots, due to the fact that physical access and/or line of sight from the existing inspection port to the upper support plate flow slot is through the flow slots of the lower five or more support plates.

Remote optical or camera techniques could be adapted to provide for improved monitoring of the upper support plate from the existing inspection port. However, experience indicates that denting generally tends to cause hourglassing in many of the lower support plate flow slots before it occurs in the upper support plate. Thus, as denting becomes more advanced, it may not be feasible to visually monitor upper support plate deformation directly.

Installation of upper inspection ports, located at one end of the tube lane just above the upper support plate, would enhance the capability to effectively and directly monitor the condition of the upper support plate, particularly for any signs of early hourglassing of the upper support plate flow slots which would indicate the need for taking appropriate preventive actions to preclude rupture of the inner row U-bends.

Apart from providing a means for visual monitoring of the upper support plate, upper inspection ports also provide access to the inner row tube U-bends to facilitate the removal of U-bend tube specimens for laboratory investigation. Laboratory examination of removed U-bend tube specimens has been performed for

a few plants to assist the licensees in their assessment of the nature and causes of stress corrosion cracks in the U-bends.

2.4.3 Value-Impact

The above discussion provides the initial basis for consideration of this potential industry action. The staff's value-impact analysis indicates, however, that generic implementation of this action would not be expected to reduce the frequency of SGTRs, nor the probabilities of core melt or significant non-core melt releases. The precursor conditions which ultimately led to the tube rupture at Surry Unit 2 are now well understood. Alternative means are available for detecting the onset of these precursor conditions, permitting timely implementation of preventive and/or corrective measures. Preventive measures could include the plugging of inner row tubes which are the tubes most susceptible to denting-induced rupture.

Eddy current testing, tube gauging, and profilometry techniques are capable of detecting very early stages of denting, before deformation of the support plate flow slots would even be observable. As denting becomes more advanced, the state of deformation of the lower support plates can be directly observed from the existing "lower" inspection ports. Experience has shown that any significant "hourglassing" of the upper support plate flow slots is generally accompanied by flow slot hourglassing of the lower support plates which can be monitored from the lower inspection port.

Once early signs of denting have been detected, installation of upper inspection ports is one of the options licensees will have in terms of ensuring that the appropriate preventive measures are implemented on a timely basis. However, it is the staff's judgment that eddy-current testing, tube gauging and/or profilometry, and lower inspection ports can also be effectively utilized for this purpose. In addition, in view of the industrywide trend toward more effective secondary water chemistry programs, and the ongoing industry development of remedial measures (e.g., boric acid treatments) to control and/or reduce rates of denting, it is unlikely that most PWRs will be confronted with severe denting problems.

Costs for installing upper inspection ports have been variously estimated to be in the $100,000 to $200,000 range by the SGOG (letter, September 30, 1982) and to be in the $300,000 to $450,000 range by SAI. There is no ORE impact associated with the installation of upper inspection ports in a preoperational steam generator. There are no offsetting cost or ORE benefits except for those plants where licensees install such ports in response to specific problems. SAI estimates the ORE associated with installation of these ports in an operational steam generator to be about 100 person-rem. As previously noted, however, there is little evidence that there will be a widespread need for such ports in the future.

SGOG commented that a generic requirement for upper inspection ports is not warranted for operating plants or plants under construction for the following reasons (letter, September 30, 1982):

(1) Visual inspection of the uppermost support plate or inner-row U-bends is not normally necessary. Denting could be detected earlier lower in the tube bundle and can be adequately characterized by eddy-current

inspection or profilometry of tubes. Tube cracking cannot be detected visually from the OD of tubes even if it does occur in the inner-row U-bends. Again, inspections from the tube ID are more useful.

(2) Ports are useful for removing sections of tubes or other steam generator internals to determine causes of degradation. For a given problem, sections are required from only a few steam generators. Moreover, samples of U-bends have already been removed from steam generators to evaluate tube cracking, and upper support plate samples have already been removed to evaluate denting.

(3) Tube samples may well be required from selected steam generators in the future to evaluate other types of degradation. However, the area of interest will not necessarily, or even likely, be the uppermost supports. Additional ports installed now may well be in the wrong place or of the wrong size to be useful later.

(4) In general, it is desirable to minimize the number of penetrations in vessels and the number of mechanical closures that may leak. Moreover, adding a penetration provides the opportunity to introduce foreign objects. These considerations argue against adding penetrations unless there is a supportable use for them.

(5) The cost of adding ports in the field is estimated to be between $100,000 and $200,000 per steam generator. As noted above, there are no particular generic benefits. Experience has shown that ports can be added later, if, when, and where they are needed.

(6) The need for additional inspection ports in a steam generator should be evaluated individually for each case. Additional ports should not be required unless there is a demonstrated need, e.g., for use in solving or determining the cause of a problem.

TVA commented that generator internals can best be monitored by one or a combination of the following methods (letter, October 13, 1982): (1) eddy-current test data analysis, (2) profilometry data analysis, and (3) flow slot measurements and remote TV camera inspection. If a sample has to be removed at an operating plant that has preinstalled inspection ports, the probability is low that the existing ports would be of the correct size and at the correct location.

WPSC commented that upper inspection ports constitute a costly investment that is not warranted. WPSC also commented that ports are not necessary if secondary water chemistry and condenser inspection programs are in effect as part of a total management control program (letter, October 4, 1982).

These comments are representative of comments from other industry sources and are generally consistent with the results of the staff's value-impact analysis.

2.4.4 Conclusions

Generic installation of upper inspection ports on preoperational steam generators would not be expected to produce reductions in SGTR frequency, the probabilities of core-melt and significant non-core-melt releases, or cost. Although implementation of this action could provide ORE benefits of about 100 person-rem in

cases where licensees later decide to install upper inspection ports in an operating steam generator, such benefits will likely be limited to a small number of plants. Thus, potential ORE reductions do not appear to be an important generic consideration. For these reasons, the staff concludes that this potential industry action should not be included as one of the generic staff recommended actions.

2.5 Secondary Water Chemistry Program

Based on the staff's value-impact evaluation, this potential industry action has been dispositioned as a staff recommended action.

2.5.1 Staff Recommended Action

Licensees and applicants should have a secondary water chemistry program (SWCP) to minimize steam generator tube degradation. The specific plant program should incorporate the secondary water chemistry guidelines in SGOG Special Report EPRI-NP-2704, "PWR Secondary Water Chemistry Guidelines," October 1982, and should address measures taken to minimize steam generator corrosion, including materials selection, chemistry limits, and control methods. In addition, the specific plant procedures should include progressively more stringent corrective actions for out-of-specification water chemistry conditions. These corrective actions should include power reductions and shutdowns, as appropriate, when excessively corrosive conditions exist. Specific functional individuals should be identified as having the responsibility/authority to interpret plant water chemistry information and initiate appropriate plant actions to adjust chemistry, as necessary.

2.5.2 Basis for Initial Consideration

Secondary-side corrosion problems with steam generators have affected a large number of PWRs to date. A description of the kinds, causes, and extent of corrosion problems which have been experienced have been documented in NUREG-0886 and NUREG-1063. These corrosion problems have caused substantial cost to the industry as a result of needed steam generator maintenance, repair, and replacement activities, and increased plant unavailability, and have resulted in significant occupational radiological exposure to workers. Two SGTR events, Point Beach 1 in 1975 and Surry 2 in 1976, are directly attributable to secondary-side corrosion problems. NUREG-0651 provides a description of these events. Improved secondary water chemistry control has been recognized by the industry in general and by the staff as an important factor in reducing corrosion in steam generators. The referenced SGOG guidelines were prepared by the Steam Generator Owners Group Water Chemistry Guidelines Committee and represent a consensus of a significant portion of the industry for state-of-the-art secondary water chemistry control.

2.5.3 Value-Impact

See Section 2.6.3

2.5.4 Conclusions

See Section 2.6.4

2.6 Condenser Inservice Inspection Program

Based on the value-impact evaluation in Section 2.6.3, the following potential industry action has been dispositioned as a staff recommended action.

2.6.1 Staff Recommended Action

Licensees and applicants should have a condenser inservice inspection program that addresses the following:

(1) procedures to implement a condenser inservice inspection program that will be initiated if condenser leakage is of such a magnitude that a power reduction corrective action is required more than once per three-month period

(2) identification and location of leakage source(s), either water or air

(3) methods of repairing leakage

(4) methodology for determining the cause(s) of leakage

(5) a preventive maintenance program

2.6.2 Basis for Initial Consideration

Condenser operating experience was summarized in EPRI-NP-481, "Steam Plant Surface Condenser Leakage Study," and EPRI-NP-2062 "Steam Surface Condensers Leakage Study Update." The studies assessed the leakage integrity of the condenser and the reliability and operability of the downstream components to the contamination introduced from the recirculation water. Air and water inleakage through the failed condenser tubing can contaminate the condensate, feedwater, steam generator water, and steam, which, in turn, degrades the structural integrity of the steam generator tubes, reheater tubes, turbine, and other components in the cooling system. The tolerance to a given leak in a given plant is a function of the impurity content of the recirculation water, the presence or absence of condensate demineralizers, and the materials in the condenser and feedwater trains. Many undesirable contaminants enter the secondary system through condenser leaks, and condenser integrity is essential to maintaining good water chemistry. Condenser tubes in the impingement, condensing, and air-removal sections of the condenser are subject to different failure rates and failure mechanisms. To some extent, failures resulting from vibration are related to operating conditions. Tubes in the impingement sector are susceptible to erosion by steam and to severance by missiles. Likewise, when ammonia-sensitive alloy tubes are located adjacent to the air-removal section of the condenser, a high incidence of ammonia-induced failures can be anticipated with all-volatile treatment (AVT) coolant water control. Localized concentrations of ammonia can be orders of magnitude greater in the vapor phase than in the bulk condensate. A high concentration of ammonia in the condensate may induce failure of copper alloys by stress-corrosion cracking.

Air inleakage into the condenser can cause corrosion of copper-containing condenser tubes and feedwater heater materials. When ammonia is also present, stress-corrosion cracking of copper-based alloys, such as aluminum brasses or admiralty bronzes can also occur. The copper-nickel alloys are more resistant

to ammonia cracking, but can still be a source of copper ions. Copper ions entering the feedwater from these sources can trigger denting reactions in the steam generators. The utilities are taking steps to eliminate the use of ammonia-sensitive alloys from the air-removal section of the condensers and to replace them with more ammonia-resistant alloy tubing. Where denting is a concern, steps are being taken to eliminate all copper alloys from the condensers, by using such materials as stainless steels (for fresh-water service), Allegheny-Ludlum 6X, or titanium. Clearly, maintenance of a tight condenser will eliminate the primary source of the oxygen and chloride ions in the system and help to control denting in the steam generators.

2.6.3 Value-Impact

This subsection addresses the staff's value-impact evaluation of staff recommended actions pertaining to SWCP and condenser inservice inspection programs (CISIPs). Because an effective CISIP is an integral element of an effective SWCP, the values and benefits estimated for improved SWCP includes those benefits to be derived from an improved CISIP.

SAI divided existing plants into three groups to evaluate the potential effect of improved SWCP on the probability of steam generator related forced outages, ruptures, and tube plugging, and steam generator replacement.

(1) Severe category - plants with significant corrosion-induced degradation of the steam generator tubes

(2) Clean category - plants with little corrosion-induced degradation of the steam generator tubes

(3) Medium category - the rest of the plants

SAI estimated that approximately one-sixth of the operating units were considered to be in the severe category, one-half in the medium category, and one-third in the clean category. Units were grouped according to their history of plugged tubes as of 1982. Units in the severe category had multiple hundreds of tubes plugged; units in the medium category had around 100 tubes plugged; and units in the clean category generally had in the low tens of tubes plugged (after 6 to 8 years of service).

SAI estimated the following percentage reductions in SGTR, forced outage, and tube plugging frequencies associated with implementation of improved SWCP:

EVENT FREQUENCY REDUCTIONS

Event	Industry Average Plant	Severe Plant
Corrosion-related SGTRs	38%	66%
All SGTRs	19%	33%
Forced outages	46%	68%
Tube plugging	71%	75%

The estimated reductions in overall SGTR frequency would result in corresponding reductions in the probabilities of core-melt and significant non-core-melt

releases. Using the value-impact criteria defined in Table 3, these correspond to a low benefit (industry average plant) and a low to medium benefit (severe plant) in terms of reduced probability of core melt, and a medium to high benefit (industry average and severe plants) in terms of reduced probability of significant non-core-melt releases.

The SAI analysis indicates that the occupational radiation exposure that would result from implementing the staff-recommended SWCP would be negligibly different from that incurred in present secondary water chemistry testing activities. SAI estimates that up to 7500 person-rem/plant can be avoided over an assumed 24-year remaining plant lifetime for plants in the severe category as compared to an estimated 1060 person-rem for plants in the medium category due to reduced or avoided SG inspection, maintenance, repair, and replacement. Thus, the staff recommendations pertaining to SWCP and CISIP appear to offer significant benefits in the area of reduced ORE.

SAI estimates the average plant lifetime costs to implement the proposed SWCP to be $1.3M. Implementation of an improved CISIP would not add significantly to this cost. Avoided lifetime costs are estimated to range from $1.3M to $12M for plants in the medium category to between $210M and $260M for plants in the severe category. Thus, implementation of an improved SWCP and CISIP appears to be very cost effective.

The SGOG stated that there is general agreement on the desirability of a SWCP (letters, September 30, 1982 and August 25, 1983). The SGOG also noted that the EPRI guidelines for SWCP (which have been incorporated into the subject staff recommendation) are indeed guidelines and that strict adherence will not guarantee that steam generators will be corrosion free and also that exceptions to the guidelines may not lead to corrosion. Moreover, the guidelines are subject to change as experience and more information are obtained. The guidelines were prepared by an SGOG committee for consideration and use by SGOG members, some of whom disagree with some sections because of plant-specific considerations. Application of the guidelines must be flexible enough to consider plant-specific design features, operating requirements and philosophy, and steam generator history. The staff acknowledges the validity of these comments and concludes that they are consistent with the staff conclusions in Section 2.6.4.

The SGOG also commented that generic requirements for a CISIP are not warranted and should not be a licensing condition on the following bases:

(1) Condenser inspection and leakage are not safety issues.

(2) Maintenance of secondary water chemistry provides utilities with a strong incentive to prevent excessive condenser leaks.

The SGOG also stated that utilities should remain free to establish the condenser maintenance plans best suited for their plants. The frequency, extent, and type of inspections can be based on:

(1) history of condenser operation

(2) the presence of on-line leak surveillance techniques, e.g., cation conductivity monitors

(3) plant design features, e.g., the role of polishers during cooling water inleakage

(4) economic considerations

Section 2.6.2 addresses the importance of maintaining the leak-tightness of the condensers from the standpoint of ensuring adequate secondary water chemistry control. The staff continues to believe that the subject CISIP should be implemented to ensure the leak-tightness of the condensers as part of a successful SWCP.

Other industry sources, including Duke Power Company (letter, January 26, 1983), Florida Power Company (letter, January 10, 1983), Alabama Power Company (letter, January 11, 1983), and Wisconsin Public Service Company (letter, October 4, 1982) stated their agreement with the value of a secondary water chemistry program and condenser ISI program. However, there were several comments that such items should not be the subject of regulatory requirements. WPSC stated that (1) the SWCP does not warrant a license condition, (2) a firm management commitment such as that at WPSC can ensure a successful control program, and (3) it is prudent management to have an operational chemistry program, which management supports, to protect the company's investment.

WPSC's comments on the condenser inservice inspection program are similar to its comments on the SWCP with the addition that, because of the costs associated with a forced outage to repair a steam generator, management should consider implementing this requirement on its own; no NRC requirement is necessary. A similar comment was provided by Alabama Power Company. The staff's response to these comments is the same as the response to the SGOG CISIP comments.

Westinghouse commented that the costs associated with reduced power operation, including shutdown, while chemistry is being corrected should be considered (letter, February 15, 1984). Further, the SAI estimate of $1M for hardware update does not consider that many plants will require significant condenser repair or replacement. The Power Authority of the State of New York (PASNY) has commented that while it is endeavoring to reduce the concentrations of impurities (at Indian Point 3) to levels within those of the SGOG guidelines, it is apparent that major plant modifications will be required to reduce all parameters to the desired levels. PASNY concludes that the costs for these modifications should be considered (letter, February 15, 1983).

The staff acknowledges that these costs have not been directly considered. However, those plants that must perform frequent power reductions or shut downs to correct out-of-specification secondary water chemistry, or that must perform extensive condenser modifications in order to avoid power reductions or shutdowns, are precisely the plants that stand to benefit the most in terms of avoided economic cost, ORE, and tube ruptures. The staff further notes that for these plants, condenser modifications should and are likely to be taken eventually as a matter of economic necessity. The staff concludes that direct consideration of these costs would not have a significant effect on its value-impact findings concerning the cost effectivenss of an improved SWCP and CISIP.

2.6.4 Conclusions

The potential industry actions concerning secondary water chemistry control (Section 2.5.1) and condenser inservice inspection programs (Section 2.6.1) can provide a 19% to 33% reduction in overall SGTR frequency, a low to medium benefit (as defined in Table 3) in terms of reduced probability of core-melt, a medium to high benefit in terms of reduced probability of significant non-core-melt releases, and substantial benefits, 1060 to 7500 person-rem, in terms of avoided occupational radiological exposures. In addition, these actions are cost effective. The staff concludes that these potential industry actions should be incorporated as staff recommended actions.

2.7 Stabilization and Monitoring of Degraded Tubes

2.7.1 Potential Industry Action

A proposal was made that licensees should conduct a study to develop criteria and procedures for plugging tubes which contain provisions for (1) the monitoring of further degradation in plugged nonleaking tubes for which the rate of further degradation cannot be reliably predicted and (2) the stabilization of degraded tubes that may be subjected to progressive degradation mechanisms having the potential to cause the tube to sever, subsequently damaging adjacent tubes.

2.7.2 Basis for Initial Consideration

A plugged tube may continue to degrade after plugging so that it can become completely severed and subsequently cause damage to adjacent tubes. The most important types of degradation, in this regard, are those that can potentially affect the entire circumference of the tube. Some of the more obvious examples are fatigue-induced circumferential cracking and fretting wear from flow-induced vibration. Monitoring the plugged tube's integrity would provide a warning of further degradation before severance or would prevent severed tubes from damaging neighboring tubes.

Implementation of techniques beyond the current conventional inservice inspection practices to monitor the integrity of plugged tubes is less important for well understood and predictable degradation mechanisms than it is for newly encountered or unpredictable degradation mechanisms. An example of a recently encountered degradation mechanism that may benefit from monitoring is the tube fretting wear from flow-induced vibration in the preheater section of Westinghouse Model D steam generators. Such wear has led to a tube leak in the Ringhals 3 plant. Operators at the Ringhals 3 plant chose to install limited leakage plugs in tubes requiring plugging. Plant operators found that the tube wear rate and modes of plant operation causing excessive wear were well defined. However, the use of the limited leakage plugs was intended to provide an earlier indication than might otherwise be gained of accelerated tube wear. (Corrective modifications to the steam generator feedwater inlet were subsequently installed at Ringhals 3 and at other Westinghouse Model D units to eliminate the source of the vibration problems.) The use of limited leakage plugs would also appear to be of interest in cases where there is uncertainty about the continued integrity of plugged tubes.

The implementation of techniques to stabilize tubes becomes more important in cases in which the potential exists for complete and/or rapid circumferential cracking. Such degradation mechanisms may be driven solely by flow-induced vibration phenomena or by corrosion assisted by fatigue. An example of circumferential cracking propagated by fatigue because of vibration induced by high fluid flows across the tubes has been encountered in the once-through steam generators (OTSGs) for tubes adjacent to the inspection lane in the vicinity of the 15th tube support plate. It has been the practice to stabilize such tubes with pluggable indications by inserting a rod inside the affected tube. The rod is attached to the plug, which is installed in accordance with conventional practices.

2.7.3 Value-Impact

SAI estimates the cost of performing this study to be about $1M. Since much of the burden of conducting this study could be shared among owners groups, the costs per plant are likely to be substantially less than this figure.

Additional cost and ORE would accrue if these studies were to lead to installation of stabilizing or monitoring devices based upon criteria derived from these studies.

The SGOG comments (letter, September 30, 1982) are summarized as follows:

(1) Of the large number of plugged tubes cited by the NRC, there has been only one isolated case of plugged tubes later causing damage to adjacent tubes. This is because (a) there are few damage mechanisms that can cause a tube to sever where it is not restrained and then damage adjacent tubes and (b) when such mechanisms exist, they usually have been recognized and accounted for in corrective actions. Any proposals aimed at controlling a situation that is already rare need to be carefully focused and reviewed to ensure they will not create more problems than they are likely to prevent.

(2) Monitoring the continued degradation of nonleaking plugged tubes may provide research data, but special actions to do so with the objective of preventing tube leaks are not warranted.

(3) Limited-leakage plugs allow internal pressurization and slight internal heating of a tube, conditions that support tensile stress and continued tube corrosion, respectively. Leaks from these plugs could not be distinguished from other small leaks. Use of such plugs would mean that some tubes might have to be plugged twice, with the attendant increase in radiation exposure.

(4) Stabilization of a degraded tube should be undertaken only when the damage mechanism could cause the tube to sever in an unrestrained region and damage adjacent tubes, and then only after the case has been individually evaluated.

(5) The reporting proposal is open ended in requiring identification of the progressive degradation mechanisms "likely to occur" as well as those that have occurred.

The SGOG comments are generally representative of other comments from the industry.

2.7.4 Conclusions

The staff has considered the industry comments on this issue. In particular, the staff agrees that there is little evidence that severence of plugged tubes and resulting damage to adjacent live tubes is a widespread industry problem. The Ginna tube rupture event did serve to point out the potential for large foreign objects, in conjunction with high cross-flow velocities, to cause tubes to sever. Increased industry awareness of the circumstances of the Ginna failure and of the need to have effective programs for the detection and prevention of loose parts is expected to minimize the potential for further occurrences of this kind. In addition, the industry has, on its own initiative, installed tube stabilizing and monitoring devices in cases in which the potential exists for flow-induced vibration to cause tubes to sever after they have been plugged. On the basis of these considerations, the staff finds there is insufficient basis for a staff position that the industry study this issue further. The staff will continue to monitor industry practice in dealing with the severed-tube issue and will take action on either a plant-specific or generic basis should it later be determined to be appropriate.

2.8 Primary-to-Secondary Leakage Limits

Based on the value-impact evaluation in Section 2.8.3, this potential industry action is categorized as a staff recommended action.

2.8.1 Staff Recommended Action

All PWRs that have Technical Specifications (TS) limits for primary-to-secondary leakage rates which are less restrictive than the Standard Technical Specification (STS) limits should implement the STS limits.

2.8.2 Basis for Initial Consideration

The STS and many plant Technical Specifications limit the primary-to-secondary leakage through all steam generators not isolated from the reactor coolant system as well as the leakage through any one steam generator not isolated from the reactor coolant system. These limits are based on two considerations.

(1) The total steam generator tube leakage limit of 1 gpm for all steam generators ensures that the dosage contribution from tube leakage will be limited to a small fraction of 10 CFR Part 100 limits in the event of a single SGTR or steamline break. This limit is consistent with the assumptions used in the design-basis analysis of this accident.

(2) The 500-gpd (0.35-gpm) leakage limit per steam generator provides added assurance that steam generator tube integrity will be maintained in the event of a postulated main steamline break (MSLB) or loss-of-coolant accident (LOCA). Permitting operation with leakage in excess of these limits increases the potential that steam generators may be vulnerable to tube ruptures during postulated accidents such as an MSLB or LOCA.

The 500-gpd limit was originally developed on the basis of leak rate and burst test data for 0.875-in.-diameter x 0.050-in.-thick Westinghouse tubes, and has been shown to be a conservative limit for smaller diameter and smaller thickness tubes utilized in later model Westinghouse steam generators. The numerical value of the STS limit is intended to ensure that tubes with through-wall cracks which are leaking at less than the leak rate limit during normal operation have sufficient residual integrity to sustain postulated accident loadings without rupture.

The leakage rate limits provide a very important indication of the existence or rate of steam generator tube degradation. Experience has shown that some forms of degradation can develop in a period of time that is shorter than the routine inspection intervals or may be difficult to detect with current ECT techniques. If such degradation occurs, the leakage rate limits act to indicate when plant shutdown, ISI, and corrective actions to ensure tube integrity should be taken.

2.8.3 Value-Impact

The STS limits are effective in minimizing both the likelihood and magnitude of offsite releases by minimizing the probability of the rupture and by limiting the transport of radioactivity into the secondary system. In addition, implementation of the STS limits provides added assurance that the steam generators will not be operated in a condition in which they may be vulnerable to single or multiple SGTRs during pressure transients, such as an MSLB.

SAI estimates that implementation of the STS limits at plants not currently implementing these limits could potentially reduce the overall PWR (baseline) frequency of SGTRs by 15% if considered as a stand-alone improvement. Assuming a 64% reduction in this SGTR frequency associated with implementation of the staff recommended actions concerning detection and prevention of loose parts and foreign objects (Section 2.1), improved secondary water chemistry programs (Section 2.5), and condenser inspection programs (Section 2.6), the staff estimates that the additional incremental reduction in SGTR frequency attributable to implementation of the STS limits to be approximately 5%. This corresponds to a low benefit (as defined in Table 3) in terms of reduced probability of core melt, and a medium benefit in terms of reduced probability of significant, non-core-melt releases.

Net cost impacts for plants not currently performing to the STS appear to be relatively low. SAI estimates that lifetime implementation costs could range to a maximum of $1.3M for those plants for which it would be necessary to incorporate revised sampling and analysis procedures in order to implement the STS limits. Lifetime avoided costs would accrue due to the reduced potential for SGTRs. SAI has estimated a potential benefit of $1.4M for affected plants, assuming implementation of the STS limits to be a stand alone improvement and assuming that SGTR repairs will involve a 60-day plant outage. With implementation of the staff recommended actions concerning loose parts and foreign objects, secondary water chemistry, and condenser inspections, however, that actual benefit would not be expected by the staff to exceed $0.5M.

SAI estimates that the ORE required to implement the STS limits are negligible.

SGOG stated that there was general agreement with the proposal for implementing consistent primary-to-secondary leakage limits for all PWRs (letter, September 30, 1982). Wisconsin Public Service Corporation (WPSC) stated that Kewaunee is already in compliance with the proposed limits. Alabama Power Company stated that it supports the STS limits but that these should not be mandated for all plants without considering the past history and the design-basis-event analysis (letter, January 11, 1983).

The Sacramento Municipal Utility District (SMUD) commented that the STS limit of 0.35 gpm is based upon data for Westinghouse tubes, and that these data are not applicable to the smaller B&W tubes (February 5, 1983). The staff agrees that the STS leak rate limit was developed on the basis of data for Westinghouse tubes, but believes that these limits can be reasonably applied to the B&W tube geometry. The staff notes, however, that limits higher than 0.35 gpm could be justified if backed up by appropriate test data indicating that such limits adequately ensure the integrity of leaking tubes during normal operating and postulated accident conditions.

2.8.4 Conclusions

The staff finds STS leakage limits are an effective means for ensuring that the dosage contribution from tube leakage will be limited to a small fraction of 10 CFR Part 100 limits in the event of either a design-basis SGTR or a design-basis MSLB. In addition, the STS 500 gpd limit/SG is an effective measure for minimizing the probability of SGTR as a consequence of an MSLB. In consideration of the above, and the medium potential to reduce the probability of significant but less-than-core-melt releases, the staff has incorporated the STS limits on allowable primary to secondary leakage as a staff recommended action.

2.9 Coolant Iodine Activity Limit

Based on the value-impact evaluation in Section 2.9.3, this potential industry action is categorized as a staff recommended action.

2.9.1 Staff Recommended Action

PWRs that have Technical Specification limits and surveillance requirements for coolant iodine activity that are less restrictive than the Standard Technical Specifications (STS) should implement the STS. Those plants identified above that also have low-head high-pressure safety-injection pumps should either: (1) implement iodine limits that are 20% of the STS values or (2) implement reactor coolant pump (RCP) trip criteria which will ensure that if offsite power is retained, no loss of forced reactor coolant system flow will occur for SGTR events up to and including the design-basis double-ended break of a single steam generator tube, and implement iodine limits consistent with the STS.

2.9.2 Basis for Initial Consideration

The basis for the recommendation that all PWRs should be consistent in adopting the STS derives from the staff's position that the STS coolant activity limits coupled with the STS surveillance requirements provide reasonable assurance that coolant activity will not contribute unacceptably to offsite doses from a

steam generator tube rupture as severe as a design-basis event, thus ensuring that offsite doses from a design-basis SGTR remain within acceptable limits. For example, 11 PWRs do not have specific limits on radioiodine but do have limits on total gamma activity. Although the total primary coolant activity might remain substantially below the total Technical Specification activity shutdown value, the actual radioiodine levels could be very high. Furthermore, the potential for iodine spiking must be considered.

The basis for the staff position that some plants should adopt 20% of the STS activity limits derived from the Ginna experience. As stated in NUREG-0916, the amount of primary-to-secondary leakage and the total amount of water and steam released to the environment during the Ginna SGTR event were larger than would normally be predicted because of valve malfunctions and operator actions. The staff found that the potential exists for doses to exceed 10 CFR Part 100 guidelines from a design-basis SGTR accident, and that these doses would occur only if a certain set of circumstances existed. These circumstances would be (1) primary coolant with iodine concentration at the STS coolant iodine concentration spiking limit of 60 μCi/g dose-equivalent iodine-131, (2) maximum flow rate through a double-ended tube rupture, (3) flow through the tube rupture prolonged for 2 or more hours, (4) filling of the steam generator and steam line of the affected steam generator, (5) releases through the affected steam generator's safety or atmospheric dump/relief valves as a two-phase mixture, and (6) conservative atmospheric dispersion factors. The actual radiological consequences of the Ginna accident were not severe because the reactor coolant's iodine concentration was very low, 0.057 μCi/g dose equivalent iodine-131 (about 2% of the plant's Technical Specification limit), and because the meteorologic conditions were far more favorable, with respect to offsite doses, than the conservative assumption used in the prior analyses.

The problems encountered with controlling and reducing reactor coolant system pressure following SGTRs appear to be more significant in plants at which the reactor coolant pumps would be manually tripped by the operator upon indication of an SGTR of the magnitude of a double-ended guillotine break. Since present SGTR emergency operating procedures proposed by many licensees require manual RCP trip when pressure drops to a predetermined plant-specific value, plants that have low-head high-pressure safety-injection pumps (HPSIPs) are more likely to require RCP trip following an SGTR than are plants with high-head pumps. Therefore, plants with low-head HPSIPs and using the present RCP trip criteria are more likely to have void formation, sustained leakage, and potentially, steam generator overfill following an SGTR.

2.9.3 Value-Impact

As part of the final safety analysis report (FSAR) safety analyses, all plants have been evaluated to ensure that a small fraction of 10 CFR Part 100 limits are not exceeded during design-basis accidents. The subject proposal will provide added assurance that coolant iodine activity will not contribute unacceptably to offsite dose during SGTR events as severe as a design-basis SGTR event. However, the SAI analysis has indicated no significant risk reduction potential for this proposal.

A small increase in ORE will probably result from increased primary coolant sampling in approximately four plants which must upgrade their surveillance programs. With the application of ALARA (as low as reasonably achievable) techniques, this ORE increase is not expected by SAI to be significant.

An increase in ORE would result if imposition of the limit required additional shutdowns to replace leaking fuel elements. A shutdown and core unloading and reloading is estimated by SAI to result in from 25 to 60 person-rem. It is not likely that such additional shutdowns would be required to achieve compliance with the STS limits; however, it is likely that earlier shutdown and fuel replacement would be required for some of the low-head HPSIP plants to meet 20% of the STS limits. The SAI analysis indicated no identifiable benefit in terms of averted ORE because of the lower iodine limits. Therefore, the staff finds that ORE is not a significant factor for the STS limits but may be a significant factor for the 20%-of-STS limits for the low-head HPSIP plants.

Minor plant lifetime costs of $400,000 are associated with expanded surveillance programs for affected plants. A significant increase in costs would result if additional shutdowns to replace leaking fuel were required. As discussed above, it is likely that such shutdowns would not be required by adoption of the STS limits; however, it is very likely that such shutdowns may be required by imposition of 20% of the STS limits. Therefore, costs are not a factor for the STS limits but may be for the 20%-of-STS limits.

ORE and cost impacts associated with 20%-of-STS limits would be unnecessary if changes in RCP trip criteria are implemented so that RCP flow is maintained during SGTRs, and the 20% limit would not be applicable. The development of reactor coolant pump trip criteria is being addressed as part of the resolution of TMI Task Action Plan Item II.K.3.5 of NUREG-0737, "Automatic Trip of Reactor Coolant Pumps During Loss of Coolant Accidents." TMI TAP II.K.3.5 is being implemented as Multi-Plant Action (MPA) G-1 and is discussed in additional detail in Section 4.4.1.

SGOG (letter, September 30, 1982) stated that it had no comments on limiting coolant iodine activity and STS limits are a good starting point; however, there may be plant-specific reasons for exceptions. Such exceptions should be considered on a case-by-case basis.

WPSC (letter, October 4, 1982) stated that it did not believe that a generic requirement was necessary; rather a program designed to maintain fuel cladding integrity will attack the problem at its source.

Rochester Gas and Electric Corp. (RG&E) commented that it submitted an analysis by letter dated November 22, 1982 which demonstrated that the STS values for iodine are acceptable for a design-basis incident under the actual Ginna thermal hydraulic transient, and, thus, the STS limits are acceptable for low-head high-pressure plants (letter, dated January 24, 1983).

The staff finds that the SGOG comment is not inconsistent with the staff's disposition of this item as a staff recommended action for plants with less restrictive Technical Specifications than the STS. The staff also agrees with WPSC that licensees should be implementing effective programs to maintain fuel cladding integrity. However, the staff recommends that all PWRs should implement the STS limits and surveillance requirements for the reasons previously stated. Regarding the comment from RG&E, the staff has requested RG&E to resubmit its analysis using more realistic assumptions regarding operator action time.

2.9.4 Conclusions

This potential industry action does not involve significant risk potential, but would provide added assurance of compliance with 10 CFR Part 100 guidelines. The staff concludes that the potential industry action concerning coolant iodine activity (Section 2.9.1) should be incorporated as a staff recommended action.

The staff acknowledges the possibly significant ORE and cost increases associated with the potential for additional refueling outages at plants implementing 20% of the STS limits in accordance with the staff recommended action. These impacts can be avoided at the subject plants by implementing appropriate reactor coolant pump trip criteria, in lieu of the 20%-of-STS limit, such that RCP trip for SGTRs up to the design basis would not be required. Appropriate reactor coolant pump criteria are being developed and implemented as part of TMI Action Plan Item II.K.3.5 and Multi-Plant Action (MPA) G-1 as discussed in Section 4.4.1.

2.10 Reactor Coolant System Pressure Control

2.10.1 Potential Industry Action and Bases

Each of the four domestic SGTRs have resulted in longer times to depressurize the reactor coolant system (RCS) to below the secondary-side pressure than was previously assumed in plant analyses. In response, the staff considered a potential requirement for licensees to evaluate further means of optimizing RCS pressure control with the objective of minimizing primary-to-secondary leakage.

2.10.2 Value-Impact

There were no ORE changes attributable to this potential action since it proposed only that a study be conducted with emphasis on the use of existing equipment. Likewise, there is no potential for a reduction in significant but less-than-core-melt releases attributable to a study. There would likely be changes in ORE and potential for significant but less-than-core-melt releases if beneficial results of such studies could be identified and were implemented. However, the value-impact of such actions would be conducted at that time as a separate action beyond the scope of this potential action for an RCS pressure control study.

SAI estimates the economic cost per plant to perform such a study to be from $30,000 to $100,000. An assessment of the cost per plant indicates that it may be more cost effective to perform a smaller number of studies which would bound all PWRs.

SGOG stated that this potential industry action could result in an extensive analytical and procedure revision effort which is not warranted (letter, September 30, 1982). SGOG also stated that the owners groups are currently evaluating means of controlling reactor coolant system pressure during a steam generator tube rupture and that NRC should not issue specific requirements until these owners group efforts are completed and reviewed.

2.10.3 Conclusions

The issue of RCS pressure control during an SGTR has been incorporated as an ongoing staff action item as discussed in additional detail in Section 4.3.2.

2.11 Safety Injection Signal Reset

Based on the value-impact evaluation in Section 2.11.3, this potential industry action is categorized as a staff recommended action.

2.11.1 Staff Recommended Action

The control logic associated with the safety-injection (SI) pump suction flow path should be reviewed and modified as necessary, by licensees, to minimize the loss of safety function associated with safety-injection reset during an SGTR event. Automatic switchover of safety-injection pump suction from the boric acid storage tanks (BAST) to the refueling water storage tanks (RWSTs) should be evaluated with respect to whether the switchover should be made on the basis of low BAST level alone without consideration of the condition of the SI signal.

2.11.2 Basis for Initial Consideration

During the Ginna event, a potential problem became apparent when the high head safety-injection pump suction had to be manually switched from the nearly depleted BAST to the RWST after the SI signal had been reset. The safety-injection logic was such that if the SI signal had not been reset, the pump suction would have been automatically switched from the BAST to the RWST upon low BAST level. However, if the SI signal has been reset, then manual operator actions are necessary to ensure that suction from the high-head SI pump is not lost. Should the operator fail to effect this changeover, the SI pump could be damaged.

An improved design may be achieved if automatic transfer from the BAST to the RWST is provided on low BAST level under all operating conditions. This is a desirable feature since in the event of a tube rupture, the contents of the BAST may not be reduced to the low-level switchover set point for 20 to 30 minutes, during which time the operators are precluded by procedures from resetting the SI signal. SI must be reset before the containment isolation (CI) signal can be reset. Resetting CI allows operation of equipment and systems that can aid in mitigating the consequences of an SGTR.

2.11.3 Value-Impact

No significant ORE changes were identified by SAI to implement the staff recommended action. SAI estimates the total economic cost per plant to be $100,000.

Few comments relative to this proposed action have been received from industry. SGOG stated that the specific example of safety injection pump suction is of such limited applicability that a generic requirement does not apply. The staff estimates that fewer than 10 plants would likely find that physical modifications are needed.

The value of the changes made pursuant to the staff's recommended actions are as follows:

(1) Since the probability of core melt as a result of SGTRs is relatively low, improvements in the safety injection logic are not warranted based solely

on core-melt probabilities. However, it has not been shown that, from an accident mitigation standpoint, acceptable plant and offsite consequences would result from an SGTR without the high-head safety-injection pumps (HHSIPs). Current final safety evaluation report (FSAR) evaluations are conducted assuming the HHSIPs are available and injecting into the RCS to control and then regain adequate RCS inventory. The HHSIPs are then throttled, or secured, as the plant is cooled and depressurized to stop the leak. No analyses exist to support adequate plant and offsite consequences without the HHSIPs, which could happen if the operator failed to properly align suction after the safety-injection actuation signal has been reset.

(2) The staff's recommendation derives from the Ginna SGTR in which safety-injection flow was maintained after the termination criteria had been met because of operator concerns about core recovery. In the other SGTRs, elevated RCS pressure because of prolonged safety injection seems to be the rule rather than the exception. Therefore, SGTRs have resulted in situations in which damage to the HHSIPs (on plants with the logic in question) has an increased likelihood.

(3) From the standpoint of operator action, the SGTR event is a most challenging accident since a variety of diagnoses and manual actions must be effected in a relatively short time. The SGTR is also one of the more frequent accidents. From the standpoint of reducing the challenges to plant operators, the safety-injection system (SIS) logic should be improved so the operator would not have to take actions to protect the most vital RCS makeup capability in the plant.

2.11.4 Conclusions

The staff concludes that the subject actions will constitute an effective approach to ensuring that plants are in compliance with GDC 21, 23, and 35, and ensuring that plants do not have design features that will, absent proper and timely operator action during an SGTR event, result in damage to the safety injection system. In view of the minimal ORE and cost impacts, the relatively high frequency of SGTRs, and the complex operator challenges associated with this type of event, and the importance of maintaining defense-in-depth, the staff has incorporated the subject potential industry action as a staff recommended action.

2.12 Containment Isolation and Reset

2.12.1 Potential Industry Action

A proposal was made that all licensees should review and evaluate the response of the letdown system to containment isolation and reset signals. Specifically, licensees should evaluate the containment isolation systems to ensure isolation of the low-pressure portion of the letdown system inside containment (and its relief valve), thereby avoiding an unnecessary RCS leak during the event.

2.12.2 Basis for Initial Consideration

During the Ginna event, the RCS letdown containment isolation valve closed, as designed, on a containment isolation signal. However, as pressurizer level

recovered later in the event, the selected letdown orifice isolation valve and the level control valve reopened as designed. Consequently, the letdown line was communicating with the reactor coolant system while the downstream portion of the letdown line remained isolated and the relief valve on the letdown line opened at a set point pressure of 600 psig. This valve relieves to the pressure relief tank and was the major contributor to the pressure relief tank level. The Ginna containment isolation design therefore caused an unnecessary and undesirable leak during an already complex event.

2.12.3 Value-Impact

SAI estimates that the cost to utilities to evaluate their containment isolation systems to be about $40,000/plant. Modifications, if found to be needed, could run as high as $400,000. The potential cost savings associated with not having to replace the rupture disk, as a consequence of overfilling the pressure relief tank and bursting the rupture disk, is estimated to be minor in comparison to the cost of implementing any necessary modifications. Similarly, ORE associated with containment cleanup activities at Ginna was estimated to have been less than 0.6 person-rem. Thus, the proposed industry action would not appear to have significant ORE benefits. Although the proposed industry action could reduce the complexity of the plant response during an SGTR, it is not estimated to result in any significant reduction in the probabilities of core-melt or significant non-core-melt releases.

2.12.4 Conclusions

In the absence of identifiable benefits in the areas of reduced probabilities of core-melt or significant non-core-melt releases, ORE, or cost, the staff concludes that this potential industry action should not be incorporated as a staff recommended action.

Table 3 Summary of value-impact evaluation

Item	Benefit in reducing probability of core melt [1] [2]	Benefit in reducing occupational radiation exposure [1]	Net economic benefit [1]	Benefit in prevention of significant non-core-melt releases [1] [3]	Remarks	Disposition
1. Prevention & detection of loose parts						
(a) Secondary-side visual inspections and QA/QC work procedures	Low to medium	Negative (medium)	Medium	High	Can prevent 45% of SGTRs	Staff recommended action
(b) Loose-parts monitoring systems (LPMS)	Low	Low	Negative (low)	Medium	Assumes secondary-side inspections are 90% effective; LPMS is 70% effective	Deleted
2. Inservice inspection of steam generator tubes						
(a) Supplemental tube inspections	Low	Negative (low to medium)	Marginal (potentially medium impact)	Medium		Staff action
(b) Full-length tube inspections	Low	Low	Low to medium	Medium	Eliminates obvious deficiency of current TS	Staff recommended action
(c) Denting inspections	Low	Low	Medium	Low to medium		Staff action

See notes at end of table

Table 3 (Continued)

Item	Benefit in reducing probability of core melt [1 2]	Benefit in reducing occupational radiation exposure [1]	Net economic benefit [1]	Benefit in prevention of significant non-core-melt releases [1 3]	Remarks	Disposition
(d) Steam generator ISI interval	Low	Low	Low	Low to medium	Precludes excessively long intervals without inspections	Staff recommended action
(e) Inspections following shutdown for repair of leakage	Low	Probably negative (low)	Probably negative (low to med.)	Low to medium		Deleted
3. Improved ECT techniques	Low	Medium	Medium	Medium		Staff action
4. Upper inspection ports	Low	Low	Low	Low		Deleted
5& 6. Secondary water chemistry and condenser inservice inspections	Low to medium	Medium to very high	Medium to high	Medium to high	Can prevent 19 to 33% of all SGTRs	Staff recommended action
7. Stabilization and monitoring of degraded tubes	N.A.	N.A.	N.A.	N.A.		
8. Primary/secondary leakage limits	Low	Low	Low (possibly low impact)	Medium	Effective in preventing SGTR during MSLB and in mitigating radiological consequences of SGTRs	Staff recommended action

Table 3 (Continued)

Item	Benefit in reducing probability of core melt [1 2]	Benefit in reducing occupational radiation exposure [1]	Net economic benefit [1]	Benefit in prevention of significant non-core-melt releases [1 3]	Remarks	Disposition
9. Coolant iodine activity limit						
- STS for all plants	Low	Negative (low)	Negative (low)	See next column	Effective in mitigating radiological consequences of SGTRs	Staff recommended action
- 20%-of-STS for selected plants	Low	Negative*	Negative*	See next column	Effective in mitigating radiological consequences of SGTRs	Staff recommended action**
10. RCS pressure control	N.A.	N.A.	N.A.	N.A.		Staff action
11. Safety injection signal reset	Low	None	Negative (low)	See next column	Effective in preventing loss of HHSIPs during SGTRs	Staff recommended action
12. Containment isolation and reset	N.A.	N.A.	N.A.	N.A.		Deleted

N.A. - Not Applicable, study only
* - Impact can be avoided by changing reactor coolant pump (RCP) trip criteria so that RCP flow is maintained during SGTR.
** - If plants with low-head HPI pumps cannot ensure RCPs won't be tripped during design-basis SGTRs where off-site power is retained.

Notes (1), (2), and (3) are on next page.

Table 3 (Continued)

Notes:

1 Low, Medium, and High are defined as follows:

	Low	Medium	High
Reduction in Core Melt Probability/RY	$< 10^{-6}$	10^{-4} to 10^{-6}	$> 10^{-4}$
Reduction in Significant Non-Core Melt Releases/RY	$< 10^{-6}$	10^{-4} to 10^{-6}	$> 10^{-4}$
Reduction in ORE (person-rem/RY)	< 5	5 to 60	> 60
Net Economic Benefit ($ Million over Plant Life)	< 1	1 to 10	> 10

2 From Table 7 in Section 3, the baseline probability of core melt from SGTR-related causes is estimated to be 5.1×10^{-6}/RY for B&W plants and 3.6×10^{-6}/RY for W and CE plants. Single SGTRs which occur as initiating events, and whose frequency is reasonably well established from operating experience (1.5×10^{-2}/RY), contribute approximately 1.1×10^{-6}/RY to these baseline core melt estimates. The balance of the baseline core melt probability estimates derive from SGTR events (including multiple SGTRs) for which only highly judgmental event probabilities are available and which may be very conservative.

Implementation of all the potential industry actions which have been dispositioned as staff-recommended actions would be expected to produce a low benefit (as defined in Note 1) given a baseline core melt probability of 1.1×10^{-6}/RY, and a medium benefit given a baseline core melt estimate of 5.1×10^{-6}/RY for B&W plants and 3.6×10^{-6}/RY for W and CE plants. The benefits shown in this table are the incremental benefits for each potential industry action.

3 The baseline probability of significant but less than core melt releases is given as 4.9×10^{-4}/RY for B&W plants and 2.3×10^{-4}/RY for W and CE plants in Table 10 of Section 3. Single tube ruptures as initiating events contribute approximately 1.9×10^{-4}/RY to the probability of these releases. Implementation of all the potential industry actions which have been dispositioned as staff-recommended actions would produce a high benefit per the definitions given in Note 1. The benefits shown in this table are the incremental benefits for each potential industry action.

3 SUMMARY OF RISK ANALYSES FOR STEAM GENERATOR TUBE RUPTURE (SGTR) EVENTS

This summary of the risk analyses addressing rupture of steam generator tubes was developed in the following manner. First, the staff's consultant, Science Applications, Inc. (SAI), performed a preliminary analysis of the risk associated with all events involving single tube ruptures. The staff reviewed that preliminary analysis as input to the final staff analysis. In addition, the staff developed independent analyses of events involving ruptures of single and multiple tubes. The SAI and staff analyses were then combined and subjected to detailed review by a team of reviewers at SAI, by the staff's Reliability and Risk Analysis Branch of the Division of Safety Technology, and by the Division of Risk Analysis of the Office of Nuclear Regulatory Research (RES). Various licensees and NSSS vendors also commented on the SAI analysis in response to NRC Generic Letter 82-02. The following analysis considered the above analyses, reviews, and comments. Although there will continue to be a diversity of views on many of the details of the analysis, there appears to be a general consensus on the significant contributors to risk, and there is agreement that the risk of core melt from events involving steam generator tube ruptures is a relatively small fraction of the overall risk of core-melt accidents.

Section 3.1 provides an assessment of SGTR event probabilities involving single and multiple tubes. Various accident sequences involving SGTRs are examined in Sections 3.2, 3.3, and 3.4. Section 3.2 discusses SGTR events challenging the reactor trip and decay heat removal functions. Section 3.3 discusses SGTRs that occur during loss-of-coolant accidents. Section 3.4 discusses SGTRs that occur concurrent with a loss of secondary system integrity. The overall probabilities, consequences, and risks associated with SGTR accident sequences leading to core melt are discussed in Section 3.5. The probabilities, consequences, and risks associated with non-core-melt releases during SGTRs occurring in conjunction with a loss of secondary system integrity are discussed in Section 3.6.

3.1 Single and Multiple SGTR Probabilities

In order to estimate the probabilities of various SGTR accident sequences, estimates of the probabilities of single and multiple steam generator tube ruptures must be developed.

3.1.1 Initiating Event Probabilities

For purposes of this analysis, the staff has assumed an SGTR frequency of 1.5×10^{-2}/RY as an industry average value. This is consistent with actual operating experience for Westinghouse plants; namely, four SGTR events during approximately 300 "mature" reactor years (i.e., reactor operating years after the first two years of reactor life through mid-1986). Although Combustion Engineering (CE) and Babcock and Wilcox (B&W) plants have not experienced actual SGTRs to date, the staff has assumed the above SGTR estimate for Westinghouse

plants to be applicable to these plants as well.* This is judged to be reasonable in view of the limited number of mature operating years accumulated at CE and B&W plants to date (i.e., 77 and 66 reactor years, respectively) and in view of the fact that extensive degradation problems have affected steam generators supplied by each of the NSSS vendors.

Each of the four SGTR events to date occurred as an "initiating" event. That is to say that each of the SGTR events occurred randomly while the reactor was being operated in a normal steady-state condition rather than occurring as a consequence of a plant transient or accident. In each case, the rupture occurred when the pressure-retaining capability of the subject tube degraded to a value less than the 1300-psid differential pressure across the tubes under normal operating conditions.

Each of the SGTRs to date involved a rupture of a single tube. It is highly improbable that two or more tubes could rupture simultaneously as a true "initiating" event during normal steady-state operation in view of random differences in flaw geometries, and therefore in pressure-retaining capabilities, which exist from tube to tube. Rupture of two or more tubes are credible only as a consequence of a plant transient or accident when the loading on the tubes becomes more severe. However, as is discussed in Section 3.1.2.2, multiple tube SGTRs involving certain initiating plant transients can be idealized as initiating events for purposes of evaluating the corresponding potential for significant radiological releases and core melt. The potential for SGTRs as consequential events is discussed in Section 3.1.2.

3.1.2 Probability of SGTRs as Consequential Events

3.1.2.1 Conditional Event Probabilities

SGTRs can potentially occur as a consequence of plant transients or accidents when loadings on the steam generator tubes are increased above normal operating loads. Although there have been no SGTRs as consequential events to date, there have been several instances in which steam generator tubes are known to have been sufficiently degraded such that they were vulnerable to rupture, given the occurrence of a severe plant transient or accident. These periods of vulnerability can be inferred from the subsequent occurrence of SGTR events at the subject plant during normal operating conditions. For a tube to be sufficiently degraded to burst under normal operating conditions when the differential pressure across the tubes is between 1300 and 1500 psid, it must first be degraded to the point where it is not capable of withstanding differential pressure loadings ranging to as much as about 2600 psid for the spectrum of plant transients and postulated accidents such as a main steamline break (MSLB). The pressure retaining capacity of a virgin, undegraded tube is generally between 9000 and 10,000 psid, depending on the tube diameter and wall thickness. During the

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*CE and B&W plants have experienced three tube failures involving relatively high primary-to-secondary leakage rates, but not sufficiently high to be classified as SGTR occurrences. These incidents involved Fort Calhoun in May 1984 (letter, June 22, 1984) and Rancho Seco and Oconee Unit 2 in May 1981 and September 1981, respectively (INPO Report 82-030). SGTR events are defined by the NRC staff to be a primary-to-secondary leak in excess of the normal charging capacity of the reactor coolant system.

time period when the pressure-retaining capabilities of one or more tubes at a plant degrade to values that are 2600 psid or less, the plant can be said to be vulnerable to rupture given the occurrence of a postulated accident involving pressure loads of this magnitude. As the pressure retaining capability of the tube(s) continues to decline below 2600 psid, the plant becomes vulnerable to rupture under less severe transients (involving pressure loadings between 1300 and 2600 psid) which may occur more often than postulated worst case accidents.

The staff has evaluated the circumstances leading to the SGTR events to date and estimated the periods during which each plant was vulnerable to rupture for postulated accidents involving a pressure differential of 2600 psid. These estimates are described in detail in Appendix B of this report. As seen in Appendix B, the staff estimates that the periods of vulnerability to rupture (under postulated accident conditions) preceding the SGTR events to date totaled 1.2 years. These estimated periods of vulnerability correspond to 2.7% of the mature reactor years accumulated to date at the four subject plants. Thus, the conditional probability for rupture associated with these periods of vulnerability is 0.027 at the four subject plants.

Apart from periods of vulnerability which were terminated as a result of SGTRs, there may have been additional periods of vulnerability which were terminated as a result of tube plugging following an inservice eddy current inspection and/or a small primary-to-secondary leak. To allow for these additional periods of vulnerability, the staff has assumed an overall conditional probability of 0.05 that one or more tubes will be vulnerable to rupture during postulated accident conditions. This assumption is comparable to the above 0.027 conditional probability estimate for the four plants which experienced SGTRs and is believed to be conservative as an industry average for all PWRs. In view of the total of 440 mature reactor years at PWRs to date, this 0.05 conditional probability estimate allows for a factor of almost 20 over the total accumulated period of vulnerability (1.2 years) estimated earlier as preceding the SGTR events to date. It is implicit in the 0.05 conditional probability assumption, therefore, that periods of vulnerability to rupture during postulated accidents are almost 20 times more likely to be terminated as a result of an inservice eddy-current inspection or small leakage event than as a result of an SGTR event.

The conditional probability estimate above is based on postulated accidents as initiating events which are assumed to involve an increase in pressure differential from the normal operating value of about 1300 psid to a maximum value of about 2600 psid. For transients involving less severe pressure loadings, the conditional probabilities for causing a SGTR are reduced. The reduction factor will range between 0 and 1.0 for transients involving peak differential pressures between 1300 psid and 2600 psid. A linear relationship between the reduction factor and the magnitude of the pressure transient can be assumed subject to the following assumptions: (1) the rate of loss of pressure-retaining capability is constant with time and (2) tubes that have degraded to a pressure-retaining capability of 2600 psid will continue to degrade until they burst during normal operating, transient, or postulated accident conditions. It is implicit in the latter assumption that periods of vulnerability to rupture under transients or postulated accidents will be terminated by a tube rupture rather than as a result of an inservice inspection or small leak. However, consistent with the earlier assumption that periods of vulnerability to rupture under postulated accidents are 20 times more likely to be terminated as a result of a small leakage event or inservice inspection than by rupture under normal operating pressures, the

probability that a tube will continue to remain in service as its pressure-retaining capability is reduced to some given value below 2600 psid is assumed to decline in a linear manner from 1.0 at 2600 psid to essentially zero (actually 0.05) at 1300 psid. Thus, the conditional probability for rupture during a given transient has been assumed to vary as the square of the ratio of the pressure increase associated with transient to the pressure increase associated with the postulated worst case accident.* This is expressed in the following equation (hereafter referred to as the conditional probability equation).

$$C_i = C_a \left[\frac{\Delta P_i - \Delta P_n}{\Delta P_a - \Delta P_n}\right]^2$$

Where: C_i = Conditional probability for one or more tube ruptures during transient "i"

C_a = Conditional probability for one or more tube ruptures during postulated MSLB accident (equals 0.05)

ΔP_i = Peak differential pressure across tubes during transient "i"

ΔP_n = Normal operating pressure differential across the tubes (typically 1300 psid)

ΔP_a = Peak differential pressure across the tubes during postulated MSLB accident (about 2600 psid)

The staff estimates in Appendix B indicate that periods of vulnerability preceding two of the four SGTR events to date generally involved a single tube. The evidence for the other two SGTR events is ambiguous with respect to whether the subject plants were vulnerable to multiple tube ruptures. Accordingly, the staff has conservatively assumed that one-half of all SGTRs occurring as consequential events will involve multiple tube ruptures. It is very unlikely that as many as ten tubes could be vulnerable to rupture during a transient without some prior warning indication (e.g., a small leak or single SGTR during normal operation). Even in the unlikely event that more than ten tubes are vulnerable to rupture for a given transient, rupture of one or a few of the weakest tubes would be expected to attenuate the pressure transient before sufficient pressure is reached to rupture the balance of the vulnerable tubes. The staff has assumed a conditional probability of 10^{-2} that SGTRs occurring as consequential events will involve more than 10 tubes.

3.1.2.2 Initiating Transients

Plant transients and accidents that have the potential for causing SGTRs as consequential events have been divided into two groups for purposes of this analysis. The first group consists of initiating plant transients or accidents which significantly increase the likelihood that the subsequent SGTR will lead to significant radiological releases to the environment and/or core melt compared to SGTRs which occur as "initiating" events. The second group consists of plant transients and accidents that do not significantly increase this likelihood.

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*The exact relationship between the conditional probability of rupture and the magnitude of the pressure transient is complex. However, the assumption of a "square" rather than a "linear" relationship reduces the resulting core melt probability estimate only by about 20%, and thus, does not have a significant effect on the outcome of this analysis.

The staff has considered the following plant transients and accidents as belonging to the first group:

(1) anticipated transients without scram (ATWS)

(2) loss of coolant accident (LOCA)

(3) non-isolable loss of secondary system integrity (e.g., main steam line break, stuck-open steam generator safety valve)

These plant transients and accidents, including their assumed frequency and severity, are discussed in Sections 3.2, 3.3, and 3.4, respectively. The corresponding potential for SGTRs as a consequence of these initiating events has been estimated from the conditional probability equation in Section 3.1.2.1.

Specific plant transients and accidents belonging to the second group (i.e., not significantly increasing the likelihood that subsequent SGTRs will lead to significant radiological releases or to core melt) have not been evaluated in detail. Consequential SGTRs falling into this second group are treated in this analysis as "initiating event" SGTRs. Single SGTRs in this category can therefore be assumed to be accounted for in the 1.5×10^{-2}/RY estimate for single SGTRs discussed in Section 3.1.1. The probability of multiple tube ruptures in this second group is assumed for best-estimate purposes to be 1.6×10^{-3}/RY. This represents the 50% confidence value estimate for an event that has never occurred; namely, zero multiple tube ruptures after 440 mature reactor years at PWRs to date. Consistent with the estimates given in Section 3.1.2.1, this 1.6×10^{-3}/RY probability for multiple tube ruptures can be broken down as follows:

1.57×10^{-3}/RY* for 2 to 10 tube ruptures

3.2×10^{-5}/RY* for >10 tube ruptures

3.2 SGTR Events Challenging the Reactor Trip and Decay Heat Removal Functions

From NUREG-0460, the conditional probability for failure of reactor trip is estimated to be 3×10^{-5}. (The Salem 1 ATWS events of February 22 and 25, 1983 indicate that the unreliability of the trip system may have been six times higher than this value; however, corrective actions are expected to reduce the probability of failure to scram to close to the estimate of 3×10^{-5}/demand.) Based on an initiating event frequency of 1.5×10^{-2}/RY for single tube rupture events (Section 3.1.1), 1.6×10^{-3}/RY for 2 to 10 tube ruptures (Section 3.1.2.2), and 3×10^{-5}/RY for >10 tube ruptures (Section 3.1.2.2), the probabilities of an ATWS as a consequence of 1 tube rupture, 2 to 10 tube ruptures, and >10 tube ruptures are 4.5×10^{-7}/RY, 4.8×10^{-8}/RY, and 9×10^{-10}/RY, respectively.

Recovery from SGTR(s) occurring in combination with an ATWS would be more difficult than for SGTR(s) not involving an ATWS. In addition, there are no emergency procedures for a combined ATWS/SGTR event. For purposes of this analysis, ATWS sequences which include SGTR(s) are assumed to result in core melt. Core-melt sequences are discussed in Section 3.5.

The staff also considered SGTRs occurring as a consequence of ATWS events. Loss-of-main-feedwater events are the most frequent of anticipated transients (about 3/RY). The staff assessment specifically addresses events in which there

*This analysis is actually based on rounded values of 1.6×10^{-3} and 3×10^{-5}/RY, respectively.

is a total loss of main feedwater, since these events produce a more severe primary pressure response during an ATWS than does a partial loss of main feedwater. On the basis of a limited survey of plant data, total-loss-of-main-feedwater events are assumed to occur at a frequency of 1/RY. This number is believed to be conservative for purposes of estimating SGTR probabilities for the entire spectrum of ATWS events.

Three ranges of moderator temperature coefficients producing pressure transients of varying severity were considered. For Westinghouse plants, the estimated conditional probability of each range of peak primary pressures was taken from NUREG-0460. Unless action is taken to trip the turbine during the brief period of time before the peak primary pressure is achieved, the secondary-side pressure will remain stable, perhaps decreasing by approximately 100 psi. If the turbine is tripped, the secondary side pressure will increase until the pressure relief set point is achieved, thus tending to partially offset the peak differential pressure across the steam generator tubes. Because of the short time interval involved (about 75 seconds), the conditional probability of turbine trip is believed small, and thus no credit for manual turbine trip was assumed in this assessment.

Conditional probabilities for an SGTR as a function of the magnitude of the ATWS pressure transients were determined from the conditional probability equation in Section 3.1.2.1.

The following summarizes ATWS sequences leading to SGTRs:

ATWS Sequence Events	Frequency or Probability		
Total loss of main feedwater	1/RY		
Failure to scram	3×10^{-5}		
Moderator coefficient in range such that peak primary pressure may be in range of:			
(1) 2650 psig (Δp = differential pressure between primary and secondary = 1800 psid)	→	→	0.5
(2) between 2650 and 3000 psig (Δp = 2150 psid)	→	0.49	↓
(3) between 3000 and 3500 psig (Δp = 2650 psid)	0.01	↓	↓
Single SGTR	2.5×10^{-2}	1.1×10^{-2}	3.7×10^{-3}
2 to 10 SGTRs	2.5×10^{-2}	1.1×10^{-2}	3.7×10^{-3}
>10 SGTRs	5×10^{-4}	2.1×10^{-4}	7.4×10^{-5}

Taking the sum of the probabilities for the three peak primary pressure cases, the overall probability of SGTRs as a consequence of ATWS is as follows:

Single SGTR	2.3×10^{-7}/RY
2 to 10 SGTRs	2.3×10^{-7}/RY
>10 SGTRs	4.4×10^{-9}/RY

To sum up, the probability of SGTRs occuring in conjunction with an ATWS (either as an initiating or consequential event) is an follows:

Single SGTR	6.8×10^{-7}/RY
2 to 10 SGTRs	2.8×10^{-7}/RY
>10 SGTRs	5.3×10^{-9}/RY

Core melt probabilities associated with other types of SGTR challanges to normal transient response functions are estimated by the staff to be 4.4×10^{-7}/RY. This is consistant with SAI estimates for core melts caused by single SGTRs in conjunction with a loss of AC power (2.4×10^{-7}/RY) and SGTRs in conjunction with a total loss of auxiliary feedwater (2×10^{-7}/RY).

3.3 SGTR Events Resulting From Loss-of-Coolant Accidents

The second category of SGTR events leading to core melt involves those sequences that include a LOCA and consequential tube failures. In these cases, the tube failures during the LOCA tend to inhibit the normal core reflood process and thereby increase the estimated peak cladding temperatures and the core melt probabilities.

Analytical and experimental investigations into the influence of tube failures on LOCA are documented in a series of reports from the Idaho National Engineering Laboratory (INEL) (NUREG/CR-0175; letters, August 8, 1978 and November 3, 1978; and INEL report, August 1977). These reports indicate that the failure of 10 or fewer tubes would increase the peak cladding temperatures to approximately 1900°F for tube failure during refill and to 1800°F for tube failure during reflood; and that failure of more than 20 tubes would have effects ranging only from slightly adverse to slightly beneficial. In all cases the leakage through the failed tubes would occur from the secondary system into the primary system. These trends are shown in Figure 1 taken from INEL report CVAP-TR-78-015 (letter, August 8, 1978). Therefore, these investigations indicate that the probability of a core melt following a LOCA would be increased for those events in which 10 to 20 tubes fail. A significant conservatism is that the experiments and calculations (described in NUREG/CR-0175; letters August 8, 1978 and November 3, 1978; and INEL report, August 1977) assumed the tubes all completely severed at the worst time in the event (refill), all the intact loop's steam generators were equally and simultaneously affected, and the broken loop steam generator was not simultaneously affected.

For purposes of the probabilistic assessment herein, a core melt probability of 0.1 has been assigned to LOCA events involving significantly elevated peak cladding temperatures, although the above analyses and experiments do not indicate that a core melt would occur. This assumption is intended to account for plant-to-plant variations and for uncertainties in this and other aspects of the ECCS response to a LOCA. In addition, the staff has conservatively assumed

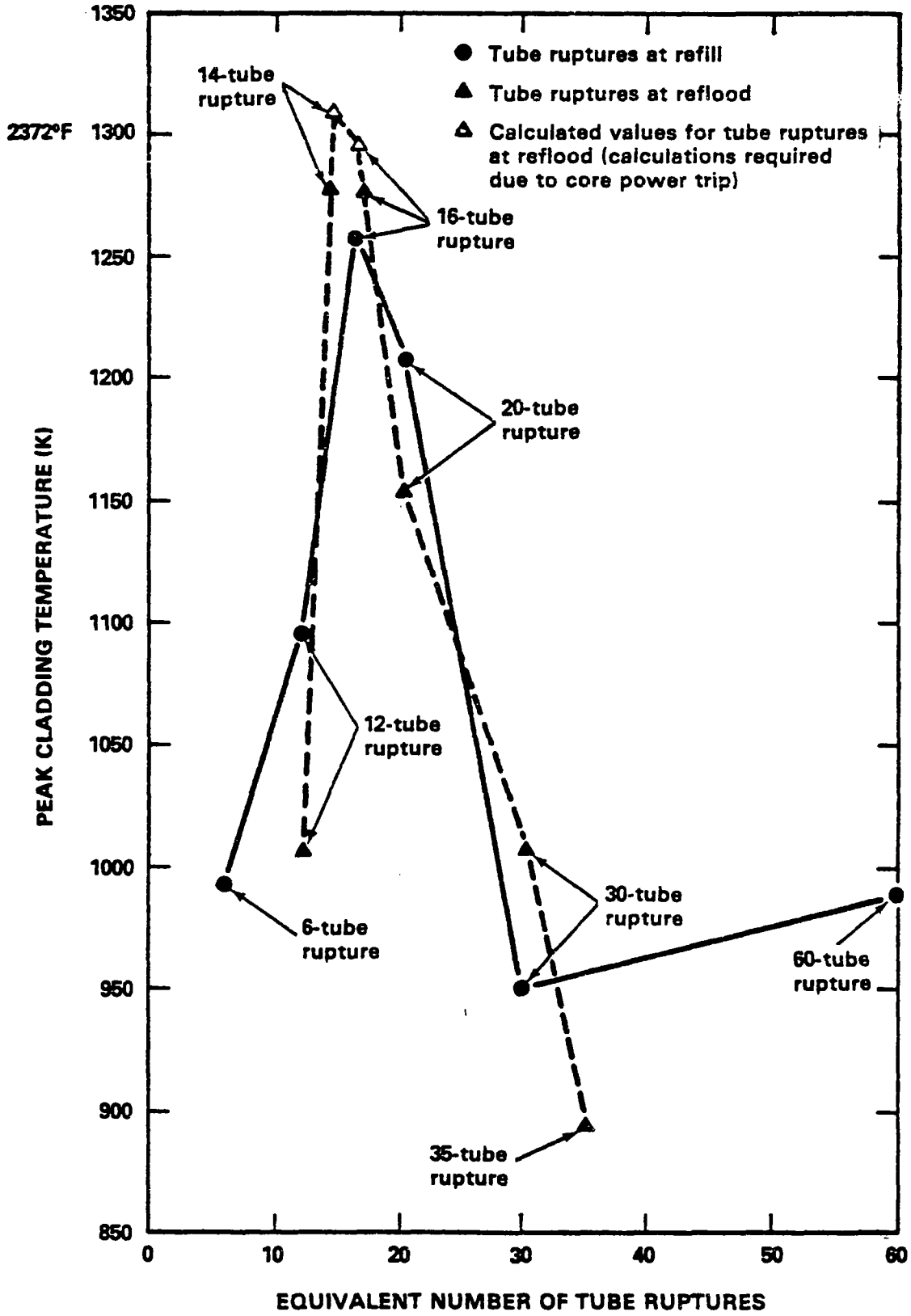

Figure 1 Maximum cladding temperatures obtained for cases with tube ruptures initiated at the start of refill and at the start of reflood

Source: Idaho National Engineering Laboratory Report CVAP-TR-78-015

significantly elevated peak cladding temperatures to be associated with 2 or more SGTRs occurring during a LOCA rather than 10 to 20 SGTRs to allow for possible uncertainties in the 10 to 20 SGTR estimate stemming from the INEL tests.

During a LOCA, the depressurization of the RCS may cause a reversal of the net pressure loading acting on the tubes from primary-to-secondary to secondary-to-primary. The conditional SGTR probability equation in Section 3.1.2.1 is not intended for specific application to transients involving a pressure reversal across the tubes. However, NRC-sponsored burst and collapse tests indicate that the reverse pressure differentials associated with LOCAs are substantially less limiting than a postulated MSLB from the standpoint of inducing an SGTR (NUREG/CR-0718). Therefore, the conditional probability of 2 or more SGTRs, given a LOCA, is assumed (very conservatively) to be 2.5×10^{-2}/RY based on the proba-bility estimates developed in Section 3.1.2.1 for MSLB.

The event sequence is as follows:

Event	Probability
(1) Large-break LOCA (NUREG-75/014)	10^{-4}/RY
(2) Failure of 2 or more tubes	2.5×10^{-2}
(3) ECCS ineffectiveness	10^{-1}
	2.5×10^{-7}/RY

Therefore, for large-break LOCAs, the core-melt probability due to concurrent SGTRs and steam binding-induced delay in core reflood is extremely low. The staff is currently performing a more detailed assessment of the risks associated with LOCA events involving concurrent SGTRs as part of NRC Generic Issue 141. This effort has been initiated to address comments submitted in a letter dated April 20, 1987, from Dan L. Johnson of San Diego, California, in response to a proposed revision to Appendix K of 10 CFR 50 concerning acceptance criteria for emergency core cooling systems which was issued for public comment in 1987 (Proposed Rules; Federal Register Vol. 52, No. 41; March 3, 1987).

3.4 SGTR Events in Combination With Loss of Secondary System Integrity or Failure To Achieve Steam Generator Isolation

This category of events includes single and multiple tube ruptures occurring in conjunction with a non-isolatable loss of secondary system integrity (outside containment) or failure of the main steam isolation valves (MSIVs). Events in this category involve escape of radioactive primary water into the secondary system and subsequently into the environment. The events are divided into three groups: those involving failure of the main steam line, those involving failure of the steam generator atmospheric dump valve or safety valves, and those involving failure of the MSIV to operate, thus preventing isolation of the damaged steam generator.

These groups of events are described in Sections 3.4.1 through 3.4.4 below. Section 3.4.5 discusses the staff's analysis of the time available to the plant operators during the various event sequences to terminate the leakage of primary coolant into the secondary system before ECCS water from the refueling water storage tank (RWST) is depleted. Probabilities for each of the event sequences considered are summarized in Section 3.4.5.

3.4.1 SGTRs and Total Loss of Secondary Integrity (Sequences 2, 5A, 5B, 8A, 8B, 8C)

Steam line failure can be either an initiating event leading to an SGTR or can occur as a consequence of an initiating SGTR event. The probability of an MSLB as an initiating event has been estimated to be 1×10^{-3}/RY for the case of an MSLB in the portion of the steam line which is outside containment but before the main steam isolation valve. A postulated worst-case peak pressure differential across the tubes of 2600 psid has been assumed. Event sequences involving SGTRs as a consequence of an MSLB have been designated as event sequences 8A, 8B, and 8C in Section 3.4.5.

The potential for a main steam line break as a consequence of an SGTR was suggested during the Ginna event when the steam lines filled with water. The staff has assessed the change in the probability of failure of the main steam line from the increased stress levels associated with the deadweight of water in the steam lines. Analyses have been performed of the increase in stress levels that would result from filling the steam lines in several plants. Information extracted from analyses on the Ginna, Zion 1, Waterford 3, and Oconee 3 plants indicates that, although in some cases the spring hangers may be loaded slightly beyond their operating range, they will not fail and that the stress levels in the main steam line will in all cases remain within the limits allowed by the ASME Code. In addition to the analyses available, the steam lines were inspected after overfilling events at Oconee and Ginna and no indications of failures or incipient failures were found. Therefore, the staff concludes that the probability of failure of the main steam line is not increased by the deadweight loading. Nor is there considered to be a significant potential for failure from waterhammer since the water in the steam lines will be essentially saturated. Accordingly, the estimates of risk in this report for event sequences that consider failure of the main steam lines are based on a conservatively determined conditional probability of main steamline failure of 1×10^{-3}/ overfill event. Event sequences involving failure of the main steam line as a consequence of an SGTR event have been designated as event sequences 2, 5A, and 5B in Section 3.4.5.

Main feedline break (MFLB) scenarios are not included in this analysis, but are thought to be no more likely to occur than main steam line breaks. Therefore, MFLB scenarios can be implicitly included by doubling the probability of an MSLB for those plants which do not have feedwater reverse flow check valves inside containment. For plants with feedwater check valves, an additional failure of the check valve would be required to cause a non-isolatable loss of secondary system integrity outside containment.

Analyses performed to support SECY 82-296 (memorandum, July 13, 1982) and NUREG-0937 have shown that in the event of an MSLB with accompanying SGTRs, the consequences with respect to reactor coolant inventory and core cooling are bounded by the spectrum of primary LOCAs. Figures 2 through 5 show the results of a double-ended MSLB and 1, 5, or 10 SGTRs at Calvert Cliffs. No credit for operator action was taken in the initial 2000 seconds, with the exception of the MSLB and one SGTR case where high-pressure injection (HPI) was throttled at 600 seconds to prevent filling the pressurizer.

In terms of stopping the loss of coolant through the broken tubes and out the broken SG steam line, the primary pressure must be reduced to atmospheric

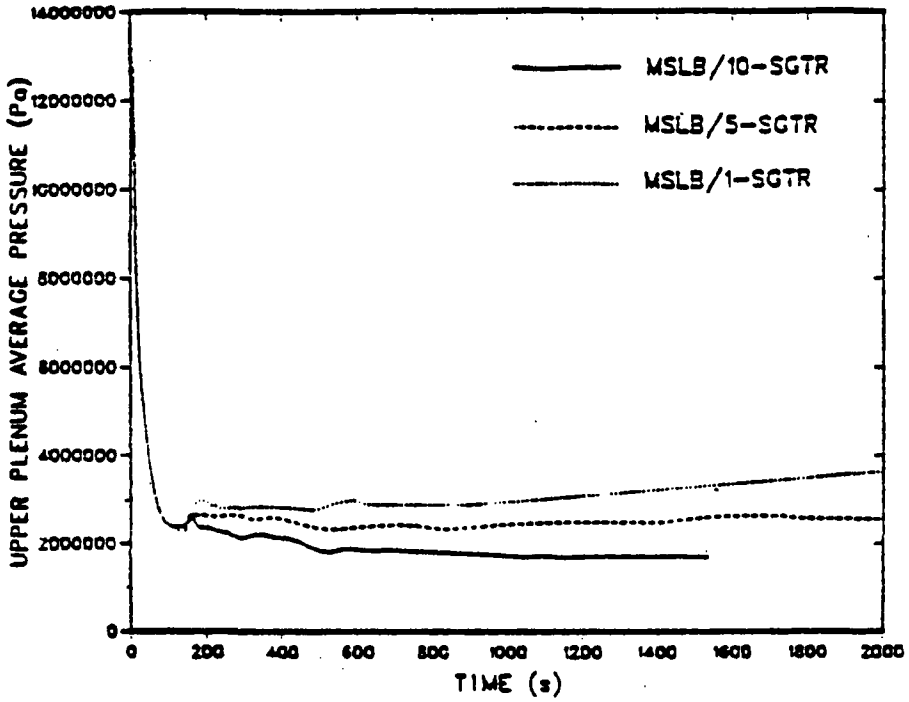

Figure 2 Primary pressure decrease for MSLB with concurrent SGTRs (Primary pressure decrease did not depend upon number of tubes ruptured until loop-A steam generator emptied at 90 seconds.)

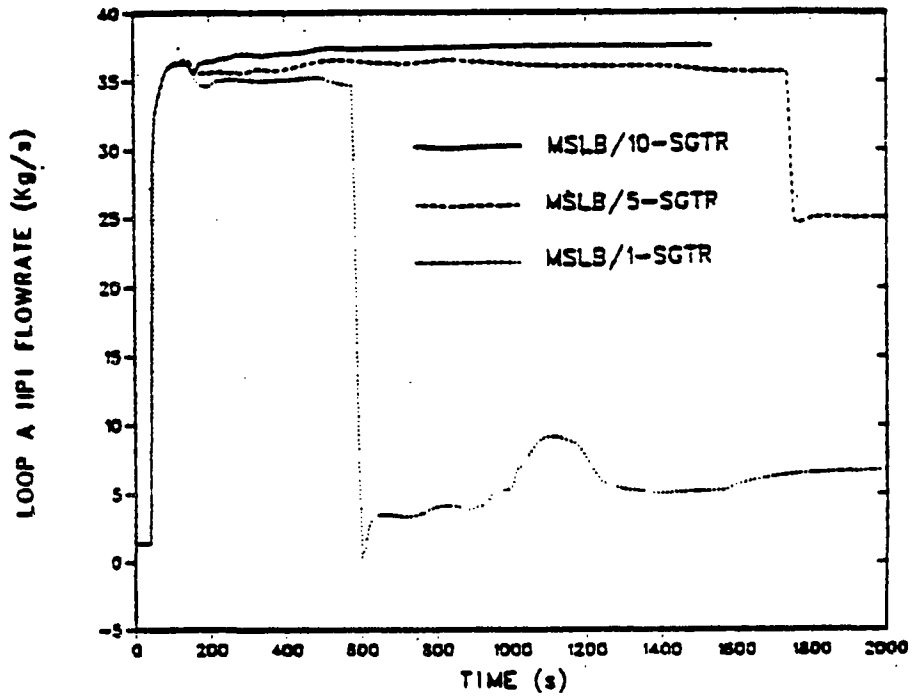

Figure 3 HPI flow rate for MSLB with concurrent SGTRs (HPI flow throttled in 1- and 5-SGTR cases at 600 seconds and 1800 seconds when primary system refilled. HPI was insufficient to refill system to normal level in the 10-SGTR case.)

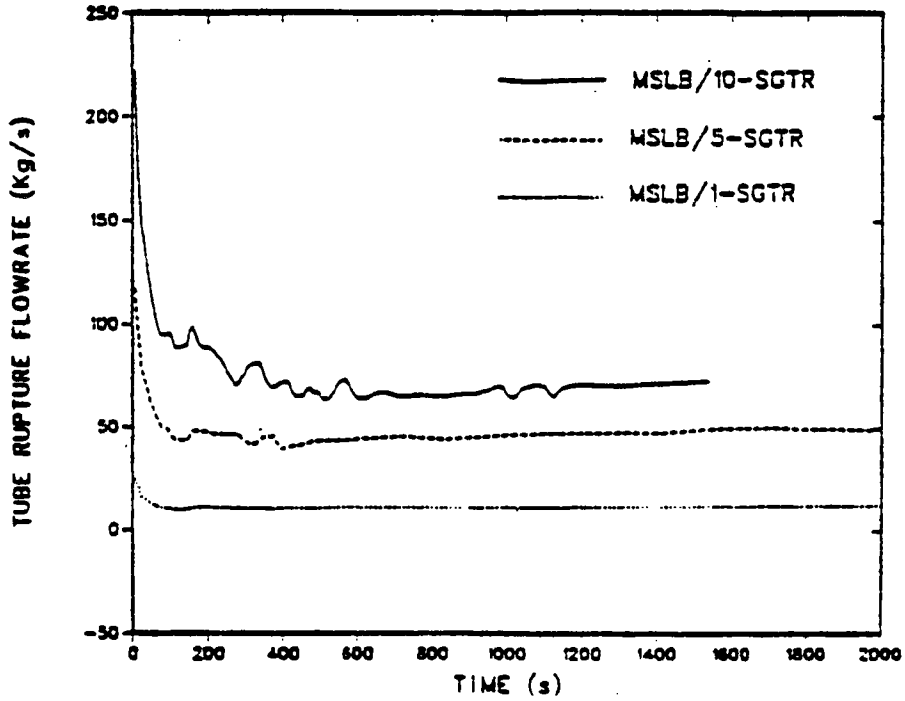

Figure 4 Tube rupture flow rate for MSLB with concurrent SGTRs (Tube rupture flow equilibrated with HPI flow (compare with Figure 3 which gives 1/2 the total HPI flow))

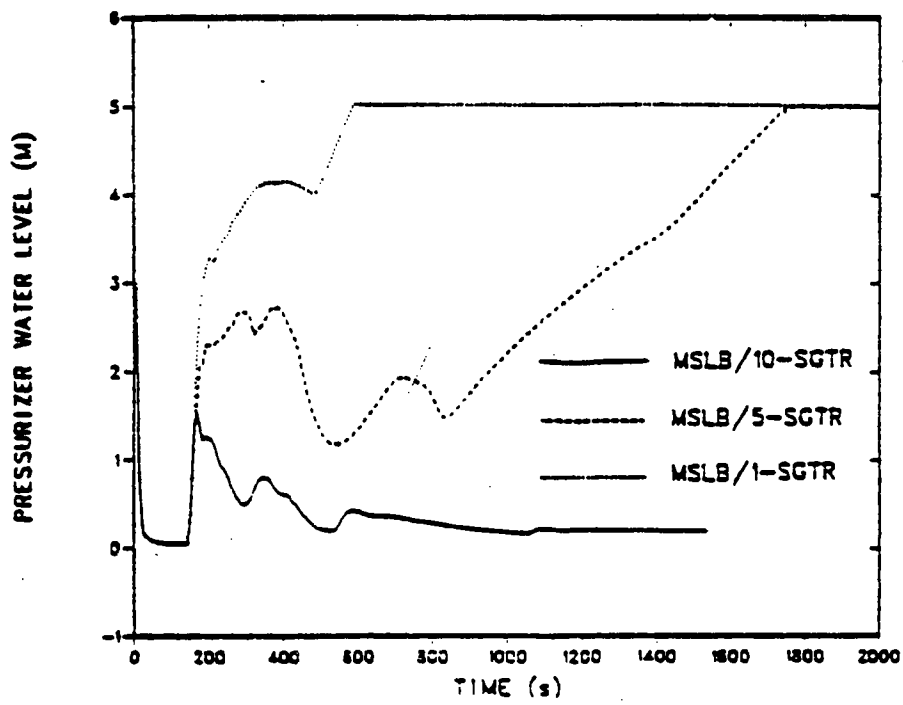

Figure 5 Pressurizer water level for MSLB with concurrent SGTRs (System refilled by HPI flow in 1- and 5-SGTR cases. HPI flow was insufficient to fill to normal level in 10-SGTR case.)

pressure. This is achieved utilizing the residual heat removal (RHR) system which requires the reactor to be first cooled to around 350°F. Once placed in operation, the RHR system would have to continue to cool down to the point where the reactor could be partially drained and depressurized. At this point, break flow would stop. This evolution takes considerable time, during which there would be a loss of coolant and RWST inventory out the break.

3.4.2 SGTRs Occurring in Conjunction With a Stuck-Open SG Safety Valve (Sequences 1, 4A, 4B, 9A, 9B, 9C)

Failure of the steam generator safety valves to fully reseat after being challenged during a plant transient occurs relatively frequently, but does not generally result in a significant pressure increase across the SG tubes which may challenge tube integrity. However, there are exceptions to this trend as evidenced by a stuck-open SG safety valve occurrence at Davis-Besse Unit 1 in March 1984 (NUREG-0090, Vol. 7, No. 1) which led to a complete blowdown of the affected steam generator and increased the pressure differential across the tubes from an initial value of 1300 psid to a maximum value of 2220 psid.

The staff has assumed a 10^{-2}/RY frequency of stuck-open safety valve occurrences at B&W plants involving pressure transients comparable in severity to the Davis-Besse event. The frequency of such events at W and CE plants is believed to be substantially less since, unlike B&W plants, the SG safety valves are generally not challenged during a turbine trip. The staff considers the frequency of such occurrences at W and CE plants to be conservatively enveloped by the estimated frequency (10^{-3}/RY) of large MSLB occurrences discussed earlier in Section 3.4.1 and which have been designated as event sequences 8A, 8B, and 8C in Section 3.4.5. Event sequences involving SGTRs as a consequence of a stuck-open steam generator safety valve have been designated as event sequences 9A, 9B, and 9C in Section 3.4.5.

In addition to being a potential initiating event for causing a subsequent SGTR, a stuck-open safety valve can potentially occur as a consequence of an SGTR as evidenced during the Ginna SGTR event. During the Ginna event, the affected steam generator filled up to the steam line safety valve as a result of primary-to-secondary leakage from continued operation of the safety injection pumps. The safety valve lifted five times at successively lower pressures and failed to fully reseat (at least twice). The failure to completely reseat contributed to the overfill problem by lowering the damaged steam generator pressure, thus raising the differential pressure across the broken tube and sustaining the leakage despite reduced primary system pressure. Although the leakage through the safety valve at Ginna was relatively small, the potential exists for a more serious safety valve failure given future SGTR/overfill occurrences and subsequent challenges to the safety valves.

In view of one such occurrence during the four SGTR events to date, the staff has assumed that one in four SGTR events involving a single tube will result in overfill of the steam generator with subsequent challenge to the steam generator safety valves or atmospheric dump valves. The staff has further assumed that all SGTRs involving multiple tubes will result in overfill and challenge to the safety valves or atmospheric dump valves. These assumptions are believed to be conservative since they take no credit for improvements in emergency operating procedures which are being implemented under TMI Task Action Plan (TAP) I.C.1 and which are expected to result in a reduction in

the potential for overfill. TMI TAP I.C.1 is discussed in additional detail in Section 4.4.3. In addition, the potential for SG overfill and its consequences, and methods for preventing its occurrence are being evaluated as part of an ongoing staff program discussed in Section 4.3.1. This ongoing program is expected to provide a basis for more realistic estimates of overfill potential and its consequences.

Given an SGTR event and subsequent overfill, the preferred approach is to utilize the atmospheric dump valves (ADVs) to avoid challenges to the SG safety valves. If a safety valve lifts and fails to reseat, there is no way to stop the release of radioactive steam into the atmosphere until the RCS has been sufficiently depressurized to halt further primary to secondary leakage. On the other hand, block valves are generally available to isolate the ADVs in the event that they should stick open or leak excessively. Furthermore, the SG safety relief valves are designed to discharge steam rather than liquid. Valve tests performed by EPRI have shown that safety valves have the potential for exhibiting severe disk chatter against the seat for cases where water is being discharged through the valves. Such chattering can cause damage to the valve seat and valve internals and thus potentially may lead to a partially or fully stuck-open safety valve.

Although the ADVs constitute the preferred means for relieving secondary-side pressure during an SGTR, the ADVs may not be available for this function as was the case at Ginna where the operators isolated the ADV by closing the block valve because they apparently misinterpreted the SGTR procedures. Furthermore, ADVs are generally not considered to be safety related and their availability is not generally required by plant Technical Specifications. The staff has assumed a 0.5 availability factor for purposes of this analysis, which is believed to be conservative.

Given the nonavailability of the ADVs, the probability of a stuck-open safety valve of sufficient magnitude to cause SG blowdown is not clear on the basis of available data. The staff has assumed a failure probability of 0.1 per event involving a challenge to the safety valve under SG overfill conditions.

Failure in this context involves failure of the valve to close sufficiently to prevent SG blowdown and/or significant leakage. This assumption is not intended to include minor safety valve leakage such as occurred during the Ginna event.

SGTR event sequences involving a stuck-open safety valve as a result of steam generator overfill are designated as event sequences 1, 4A, and 4B in Section 3.4.5.

3.4.3 SGTRs and MSIV Failures (Sequences 3, 6A, 6B)

For single or multiple SGTRs, the damaged steam generator must be isolated from the rest of the secondary system. Since the intact steam generators are used to cool the RCS to allow RCS depressurization to stop the leak, the steam pressure in the intact steam generator will be decreased with time. If the damaged steam generator cannot be isolated from the intact steam generators, then the damaged steam generator pressure will drop along with the intact steam generator pressure. Primary system pressure would be lowered along with RCS temperature in an effort to equalize pressure across the damaged tubes. However,

primary pressure must always be maintained high enough to maintain adequate RCS subcooling and an adequate temperature difference for decay heat removal. If the damaged and intact steam generators are at the same pressure (because of failure to isolate), subcooling in the primary and pressure equalization across the damaged tubes cannot be attained, and break flow would continue until the RCS reached atmospheric pressure.

If the MSIV of the damaged steam generator fails to close, the damaged generator could be isolated by utilizing the intact SG MSIVs; the associated atmospheric relief valves would be utilized for RCS cooldown and decay heat removal. In the scenarios in which the MSIV of the damaged steam generator is assumed to fail, the staff has assumed that the steam bypass system continues to function to maintain the steam system pressure (hence the back pressure on the damaged SG tubes) at about 900 psig. If the bypass system failed to maintain the value because of a loss of offsite power, circulation water, or other failures, the SG safety valves would maintain pressure no higher than about 1000 psig. Leakage into the damaged steam generator and the associated steam system would continue until the RCS pressure was reduced to this value.

SGTR sequences involving failure to close the MSIVs are designated as event sequences 3, 6A, and 6B in Section 3.4.5.

3.4.4 Tube Ruptures Affecting Multiple Steam Generators (Sequences 7A, 7B)

Should each steam generator be affected by one or more SGTRs, the operator would be required to cool down and depressurize the RCS using at least one faulted steam generator. The use of the faulted steam generator would result in continuous leakage of primary coolant into the secondary system during the entire cooldown process. This would lead to increased releases of radioactive material into the environment. It is assumed in this analysis that the primary coolant would be cooled by opening the MSIV for one of the faulted steam generators and dumping steam to the condensers in lieu of opening the atmospheric dump valve to minimize the offsite release.

If multiple SGTRs affecting multiple steam generators occur in combination with a loss of secondary system integrity, the sequence of events leading to core melt would be expected to occur over a longer period of time than if the same number of SGTRs occurred in only one steam generator. This gives the operator more time to depressurize the RCS. This is due to the likelihood that the loss of secondary system integrity (MSLB, stuck-open safety valve, etc.) will affect only one of the secondary system loops, leaving the other secondary loop or loops with partial or complete pressure control capability, respectively. Maintenance of elevated pressures in the other loops reduces or eliminates the leakage into these loops. Thus, for a given number of SGTRs in combination with a loss of secondary system integrity, it is conservative to consider the SGTRs to occur in one steam generator.

Given a multiple steam generator tube rupture occurrence, the probability that the ruptures will occur in more than one steam generator is less than one since the degradation will sometimes be more advanced or more widespread in one steam generator than in the other steam generators. The staff has assumed a probability of 0.5 that a multiple tube rupture event will involve both steam generators of a two-loop plant as a reasonably conservative estimate.

SGTR sequences involving tube ruptures in each steam generator of a PWR plant are designated as event sequences 7A and 7B in Section 3.4.5.

3.4.5 RWST Depletion Time Calculations

In all SGTR scenarios, whether or not there are other compounding failures, there is a loss of RWST inventory out the break. This fluid is permanently lost for the function of maintaining RCS inventory since there would be no way of providing a recirculation flow path from the steam generator to the charging pump or safety injection pump sections.* Calculations have shown (memorandum, July 13, 1982 and NUREG-0937) that in the case of large MSLBs with 1, 5, or 10 double-ended tube breaks, the core remains covered and cooled, with adequate means of removing core decay heat, but the operator must cool and depressurize the RCS to stop the loss of RWST fluid. The time when the RWST would be depleted without this cooldown depends, to a large extent, on the specific plant. The calculations show that, in general, as expected, the time to deplete the RWST is lower for a larger number of broken tubes. Tables 4A, 4B, and 4C show the plant status at 2500 seconds. Those results were taken from calculations performed for the staff by Los Alamos National Laboratory (LANL) to support USI A-3, A-4, A-5 resolution, and are similar to those described in Section 3.4.1.

It should be noted that for W and B&W plants in the cases of five or more SGTRs with an MSLB, the RCS depressurizes to the point of accumulator injection, which helped to refill and stabilize the pressure. The CE plant pressure did not drop to the accumulator injection point because of the relatively low accumulator injection pressure. These calculations take no credit for operator action to affect RCS depressurization. The RCS cooldown rate shown indicates that the SI flow alone, in general, is sufficient to cool the RCS at an appreciable rate. However, for CE, the system temperature was stable for 1 and 5 SGTRs.

Table 5 shows the summary of systems performance for SGTRs with a partial loss of secondary integrity. These calculations (letter, December 20, 1982) were done for Zion 1 assuming the secondary safety valve stuck open upon initial opening. In these calculations, limited operator actions were assumed to manually trip all RCPs, to throttle HPI, and to initiate an RCS cooldown using the intact steam generators 15 minutes into the event. The results shown in Table 5 are taken before operator actions were assumed at 900 seconds, thus representing a "no operator action" case.

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*For cases involving a total or partial loss of secondary system integrity this is obvious. For other cases, fluid may flow back into the primary system once RCS pressure is reduced below damaged SG pressure.

Table 4A Summary of systems response[1] to SGTRs with total loss of secondary integrity (B&W, TMI-1)

No. of tubes	RCS pressure, psig	RCS temp., °F	RCS cooldown rate, °F/hr	RCS leakage, gpm[2]	Hours to deplete RWST[3]
1	2030	548	0	414	15.7
5	870	485	200	1275	5.1
10	625	485	160	1275	5.1

[1]Comparisons are at 1000 seconds.
[2]System is repressurizing, hence break flow is increasing.
[3]RWST capacity in 388,000 gallons.

Table 4B Summary of systems response[1] to SGTRs with total loss of secondary integrity (CE, Calvert Cliffs)

No. of tubes	RCS pressure, psig	RCS temp., °F	RCS cooldown rate, °F/hr	RCS leakage, gpm	Hours to[2] deplete RWST
1	507[3]	440	Stable	191	34.9
5	362	395	Stable	765	8.7
10	290	368	162	1200	5.6

[1]Comparisons are at 1500 seconds.
[2]RWST capacity is 400,000 gallons.
[3]Pressures are slowly rising in all cases.

Table 4C Summary of systems response[1] to SGTRs with total loss of secondary integrity (Westinghouse high head, Zion)

No. of tubes	RCS pressure, psig	RCS temp., °F	RCS cooldown rate, °F/hr	RCS leakage, gpm	Hours to deplete RWST[2]
1	1522	467	65	350	18.5
2	1130	413	325	733	8.8
5	652	359°F	400	1200	5.4
10	NC	NC	NC	NC	NC
20[3]	190	378		2500-6000[4]	1 to 2

Note: NC - Not calculated

[1]Comparisons are at 1000 seconds.
[2]RWST capacity is 389,000 gallons.
[3]These values do not come from specific transient calculations, but from scoping calculations based on HPSI and LPSI characteristics and estimated break characteristics for a W low-head plant.
[4]For scenarios involving a stuck-open SG safety valve, the flow would be limited to the valve capacity of approximately 2000 gpm.

Table 5 SGTRs and stuck-open SG safety valves (Zion)

No. of tubes	RCS pressure, psig	RCS temp., °F	RCS cooldown rate, °F/hr	RCS leakage, gpm	Hours to deplete RWST
1	1160[1]	540	-	320	20.3
2	1160[2]	510	200	640	10.1

[1]Pressure is dropping.
[2]Pressures are equal at 15 minutes, although pressure is still decreasing for the 2-SGTR case and is stable for the 1-SGTR case.

Table 6 shows the systems response during events in which the MSIV fails to close, and the damaged SG pressure is maintained at about 950 psig by either the steam dump system or by the atmospheric dump valves.

Table 6 Summary of systems response to single and multiple tube rupture with failure of the MSIV

Number of tubes ruptured	Equilibrium RCS pressure (psig)	Equilibrium RCS-SG leak (gpm)	Hours to depletion of RWST
1	1370	380	13
2	1200	600	8
5	1000	760	7
10	930	810	6
20 or more	∿900	830	6

3.4.6 Event Sequences

The following material describes the event sequences for this category of SGTR failures. The probabilities that the operator would fail to take action are based on failure of the operator to cool down and depressurize the RCS within the estimated time periods to RWST depletion as given in Tables 4, 5, and 6.

Event sequences 4A, 4B, 5A, 5B, 6A, and 6B involve multiple tube ruptures which are assumed to occur in a single steam generator. The multiple tube rupture frequencies assumed in these sequences are 50% of the frequencies given in Section 3.1.2.2, because it has been conservatively assumed in sequences 7A and 7B that the other 50% of the frequencies given in Section 3.1.2.2 involve at least one tube rupture in each steam generator at the plant.

Sequence 1

Event	Probability
(1) Single SGTR	1.5×10^{-2}/RY
(2) SG overfill	0.25
(3) SG safety valve challenge (i.e., ADV not available)	0.50
(4) SG safety valve fails open	10^{-1}
(5) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - ∿20.3 hours available for a 340°F cooldown - from Table 5)	10^{-3}
	1.9×10^{-7}/RY

Sequence 2

Event	Probability
(1) Single SGTR	1.5×10^{-2}/RY
(2) SG overfill	0.25
(3) Main steamline failure consequential	10^{-3}
(4) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - ∿15.7 hours available for a 350°F cooldown - from Table 4A)	10^{-3}
	3.8×10^{-9}/RY

Sequence 3

Event	Probability
(1) Single SGTR	1.5×10^{-2}/RY
(2) MSIV failure to isolate SG	10^{-3}
(3) Failure to depressurize RCS to 900 psig before RWST is exhausted (operator error - 13 hours available to depressurize RCS to 900 psig to stop break flow - from Table 6)	10^{-4}
	1.5×10^{-9}/RY

Sequence 4A

Event	Probability
(1) Multiple SGTR (2 to 10 tubes)	8×10^{-4}/RY*
(2) SG overfill	1.0
(3) SG safety valve challenge (ADV not available)	0.5
(4) SG safety valve sticks open	10^{-1}
(5) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - 5.1 hours available for a 285°F cooldown - from Table 4A)	10^{-2}
	4×10^{-7}/RY

*This value represents 50% of the frequency estimate given in Section 3.1.2.2 to be consistent with the frequencies assumed for event sequences 7A and 7B.

Sequence 4B

Event	Probability
(1) Multiple SGTR (> 10 tubes)	2×10^{-5}/RY*
(2) SG overfill	1.0
(3) SG safety valve challenge (ADV not available)	0.5
(4) SG safety valve sticks open	10^{-1}
(5) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - 2.5 hours available for a 170°F cooldown - from Table 4C)	10^{-1}
	1×10^{-7}/RY

Sequence 5A

Event	Probability
(1) Multiple SGTR (2 to 10 tubes)	8×10^{-4}/RY*
(2) SG overfill	1.0
(3) Main steamline failure	10^{-3}
(4) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - 5.1 hours available for a 285°F cooldown - from Table 4A)	10^{-2}
	8×10^{-9}/RY

Sequence 5B

Event	Probability
(1) Multiple SGTR (> 10 tubes)	2×10^{-5}/RY*
(2) SG overfill	1.0
(3) Main steamline failure	10^{-3}
(4) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error ~1 hour for a 170°F or less cooldown - from Table 4C)	0.5
	1.0×10^{-8}/RY

Sequence 6A

Event	Probability
(1) Multiple SGTR (2 to 10 tubes)	8×10^{-4}/RY*
(2) MSIV fails to isolate affected SG	10^{-3}
(3) Failure to depressurize RCS before RWST is exhausted (operator error ~7 hours for depressurization to 900 psig - from Table 6)	10^{-3}
	8×10^{-10}/RY

*This value represents 50% of the frequency estimate given in Section 3.1.2.2 to be consistent with the frequencies assumed for event sequences 7A and 7B.

Sequence 6B

Event	Probability
(1) Multiple SGTR (more than 10 tubes)	2×10^{-5}/RY*
(2) MISV fails to isolate SG	10^{-3}
(3) Failure to depressurize RCS before RWST is exhausted (operator error - 6 hours for depressurization to 900 psig - from Table 6)	10^{-3}
	2×10^{-11}/RY

Sequence 7A

Event	Probability
(1) Multiple SGTRs (2 to 10 tubes) (affecting all SGs)	8×10^{-4}/RY
(2) Intentional opening of MSIV and steam dump valve for at least 1 SG	1.0
(3) Failure to depressurize RCS before RWST is exhausted (operator error - 5.1 hours to cool RCS from 485°F to 350°F where RHR system is activated - from Table 4A which is extremely conservative for this case)	10^{-3}
	8×10^{-7}

Sequence 7B

Event	Probability
(1) Multiple SGTRs (10 or more tubes) (affecting all SGs)	1.5×10^{-5}/RY
(2) Intentional opening of MSIV and steam dump valve for at least 1 SG.	1.0
(3) Failure to depressurize RCS before RWST is exhausted (assumed value - depletion time estimates cannot be determined from Tables 4, 5, or 6)	10^{-2}
	1.5×10^{-7}

Sequence 8A

Event	Probability
(1) Large steamline break (containment wall to MSIV) (peak Δp = 2600 psid)	10^{-3}/RY
(2) Consequential single SGTR	2.5×10^{-2}
(3) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - ~15.7 hours available for a 350°F cooldown - from Table 4A)	10^{-3}
	2.5×10^{-8}/RY

*This value represents 50% of the frequency estimate given in Section 3.1.2.2 to be consistent with the frequencies assumed for event sequences 7A and 7B.

Sequence 8B

Event	Probability
(1) Large steamline break (containment wall to MSIV) (peak Δp = 2600 psid)	10^{-3}/RY
(2) Consequential multiple SGTRs (2 to 10 tubes)	2.5×10^{-2}
(3) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - 5.1 hours available for a 285°F cooldown - from Table 4A)	10^{-2}
	2.5×10^{-7}/RY

Sequence 8C

Event	Probability
(1) Large steamline break (containment wall to MSIV) (peak Δp = 2600 psid)	10^{-3}/RY
(2) Consequential multiple tube ruptures (more than 10 tubes)	5×10^{-4}
(3) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - ~1 hour for a 170°F cooldown - from Table 4C)	0.5
	2.5×10^{-7}/RY

Sequence 9A

Event	Probability
(1) Stuck-open SG safety valve (B&W plants only) (peak Δp = 2220 psid)	10^{-2}/RY
(2) Consequential single SGTR	1.3×10^{-2}
(3) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - ~20.3 hours available for a 340°F cooldown - from Table 5)	10^{-3}
	1.3×10^{-7}/RY

Sequence 9B

Event	Probability
(1) Stuck-open SG safety valve (B&W plants only) (peak Δp = 2220 psid)	10^{-2}/RY
(2) Consequential multiple SGTRs (2 to 10 tubes)	1.3×10^{-2}
(3) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - 5.1 hours available for a 285°F cooldown - from Table 4A)	10^{-2}
	1.3×10^{-6}/RY

Sequence 9C

Event	Probability
(1) Stuck-open SG safety valve (B&W plants only) (peak Δp = 2220 psid)	10^{-3}/RY
(2) Consequential multiple SGTRs (>10 tubes)	2.5×10^{-4}
(3) Failure to depressurize RCS to atmospheric pressure before RWST is exhausted (operator error - 2.5 hours available for a 170°F cooldown - from Table 4C)	10^{-1}
	2.5×10^{-8}/RY

3.5 Core-Melt Sequences

A summary of all of the sequences contributing to the core-melt probability for SGTR events is shown in Table 7. This table presents the event sequences, core-melt probabilities, and associated risk estimates. These risk estimates are based upon consideration of potential releases and calculations of the potential health effect consequences of such releases as discussed below.

It can be seen from Table 7 that initiating event SGTRs, whose frequency is known from operating experience, contribute only 1.1×10^{-6}/RY to the overall probability of core melt from SGTR-related causes. The balance of the core-melt estimate is associated with consequential event SGTRs whose frequency is more uncertain, particularly consequential SGTRs involving multiple tube ruptures. The staff has made a number of conservative assumptions to ensure that actual multiple tube frequencies are not grossly underestimated. However, this may have resulted in conservative estimates of the frequency of multiple tube ruptures and the corresponding probability of core melt.

3.5.1 Determination of Radionuclide Releases

None of the core-melt sequences listed in Table 7 has been subjected to detailed scenario-specific analysis of potential radionuclide releases to the atmosphere. Qualitative considerations have, however, led to judgments about release potentials based upon analogies to sequences and release characterizations used in the Reactor Safety Study (NUREG-75/014).

For events involving multiple tube ruptures and a total loss of secondary integrity, it is important to determine the amount of fluid above the broken tubes because when core damage commences and fission products are released, water in the steam generator above the broken tubes presents a mechanism for retaining those fission products. The water would significantly reduce the amount of fission products escaping to the environment, and would tend to lower the predicted release.

For large MSLBs and large numbers of broken steam generator tubes, the system response can be broken into three phases: (1) initial blowdown of the faulted SG; (2) dry SG, HPSI operation, cooling of the RCS, and loss of mass into the SG which is gradually filling as RCS temperature drops; (3) RWST expended, heat transfer to the damaged SG, break flow to damaged SG. Using the results shown in Table 4C, the staff calculated the RCS temperature and faulted SG contents

Table 7 Summary of probabilities, consequences, and risks for SGTR events leading to core melt

Sequence	Probability (1/RY)	Release type	Mean consequences: Deaths/event Early	Mean consequences: Deaths/event Latent	Risk: Deaths/RY Early	Risk: Deaths/RY Latent
Loss of Secondary System Integrity						
1 Single SGTR + SGSV stuck open	1.9×10^{-7}*	2	0	450	0	8.6×10^{-5}
2 Single SGTR + MSLB	3.8×10^{-9}	2	0	450	0	1.7×10^{-6}
3 Single SGTR + MSIV Failure	1.5×10^{-9}	3	0	25	0	3.8×10^{-8}
4A Mult. (2-10) SGTRs + SGSV stuck open	4×10^{-7}	2	0	450	0	1.8×10^{-4}
4B Mult. (>10) SGTRs + SGSV stuck open	1×10^{-7}	1	11.7	1500	1.2×10^{-6}	1.5×10^{-4}
5A Mult. (2-10) SGTRs + MSLB	8×10^{-9}	2	0	450	0	3.6×10^{-6}
5B Mult. (>10) SGTRs + MSLB	1.0×10^{-8}	1	11.7	1500	1.2×10^{-7}	1.5×10^{-5}
7A Mult. (2-10) SGTRs in mult. SGs	8×10^{-7}	3	0	25	0	2.0×10^{-5}
7B Mult. (>10) SGTRs in mult. SGs	1.5×10^{-7}	3	0	25	0	3.8×10^{-6}
8A MSLB + single SGTR	2.5×10^{-8}	2	0	450	0	1.1×10^{-5}
8B MSLB + multiple SGTRs	2.5×10^{-7}	2	0	450	0	1.1×10^{-4}
8C MSLB + multiple (>10) SGTRs	2.5×10^{-7}	1	11.7	1500	2.9×10^{-6}	3.8×10^{-4}
9A SGSV stuck open + 1 SGTR	1.3×10^{-7}**	2	0	450	0	5.9×10^{-5}**
9B SGSV stuck open + 2-10 SGTRs	1.3×10^{-6}**	2	0	450	0	5.9×10^{-4}**
9C SGSV stuck open + >10 SGTRs	2.5×10^{-8}**	1	11.7	1500	2.9×10^{-7}**	3.8×10^{-5}**
LOCA						
1 LOCA + mult. (10-20) SGTRs	2.5×10^{-7}	2	0	450	0	1.2×10^{-4}
Loss of Decay Heat Removal (DHR)						
1 SGTR + loss of DHR	4.4×10^{-7}	2	0	450	0	2.0×10^{-4}
2 2-10 SGTRs + loss of DHR	3.5×10^{-8}	2	0	450	0	1.6×10^{-5}
3 >10 SGTRs + loss of DHR	7.0×10^{-10}	1	11.7	1500	8.2×10^{-9}	1.1×10^{-6}
ATWS						
1 ATWS + single SGTR	6.8×10^{-7}	2	0	450	0	3.1×10^{-4}
2 ATWS + 2-10 SGTRs	2.8×10^{-7}	2	0	450	0	1.3×10^{-4}
3 ATWS + >10 SGTRs	5.3×10^{-9}	1	11.7	1500	6.2×10^{-8}	8.0×10^{-6}
TOTAL (W, CE plants)	3.9×10^{-6}				4.3×10^{-6}	1.7×10^{-3}
(B&W plants)	5.3×10^{-6}				4.6×10^{-6}	2.4×10^{-3}

*$1.9 \times 10^{-7} = 0.00000015$
**Estimates for event sequences 9A, 9B, and 9C are applicable to B&W plants only.

when the RWST is depleted. Using conservative assumptions,* the staff calculated that there would be significant water inventory in the faulted SG at the time the core first uncovers. However, staff calculations could not assure the break would be covered in all cases for all plants. The staff has examined the event sequences and their associated release categories given in the Reactor Safety Study (NUREG-75/014) and has classified the release characterizations for SGTR events shown in Table 7 on the basis of similarities of sequences with respect to radionuclide release transport, and deposition or decontamination mechanisms.

Release Type 1 is a modified PWR-3 release category as described in NUREG-75/014. The following factors have been changed in order to achieve a better estimate of actual consequences.

Factor	PWR-3	Modified (Release Type 1)
Time to release, hr	5	1
Warning time, hr	2	1
Release height, m	0	10

Release Types 2 and 3 represent NUREG-75/014 PWR-4 and PWR-6 releases, respectively.

3.5.2 Calculation of Consequences and Risks

The risks of the accident sequences presented in Table 7 represent estimates for a typical PWR. Selected accident consequences were determined using "CRAC," a code provided by Sandia National Laboratories (latent and early fatalities). The release fractions and release characteristics for all three scenarios, except as noted above, are taken from Table 5-1 of the Reactor Safety Study (NUREG-75/014). Byron Station was used in the evaluation as a representation of an "average" PWR site.** The consequences shown in Table 7 are conditioned upon the occurence of the event sequence and are shown in terms of early fatalities and latent fatalities. Using the probabilities of each sequence occurring, the total risk (i.e., consequences multiplied by probability of occurrence) to the public per year of plant operation is also shown in Table 7. It should be noted that the consequences and risks could be larger or smaller than shown in Table 7 because of such factors as population, meteorology, and protective action assumptions, but the relationships among impacts of various sequences should remain more or less constant.

3.6 Non-Core-Melt Sequences

Since all the sequences that involve a loss of secondary integrity also involve a significant release of primary coolant to the environment, even without a

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*The staff assumed no heat transfer to the intact SGs and no operator action to reduce RCS pressure or to initiate auxiliary feedwater to add inventory to the faulted steam generator.

**Population distribution, protective actions, and meteorological input to the code were equivalent to those presented in the Byron Station Final Environmental Statement (NUREG-0848).

core melt, the probability and consequences of the corresponding non-core-melt sequences have been analyzed. Although these sequences assume correct operator action to depressurize the RCS to atmospheric pressure at a rate corresponding to a 100°F/hr cooldown, they also involve postulated failures beyond the current design basis. Therefore, the probability of these sequences is the same as that for sequences 1 through 9 above, except for the assumption relative to operator action. These releases did not include possible overpower-induced cladding failures (pellet-cladding interaction (PCI)), neither were undercooling-induced cladding failures (departure from nucleate boiling (DNB)) included. It is not expected that undercooling-induced cladding failures would occur; however, the staff is currently assessing the potential for overpower-induced fuel failures under a variety of accident and transient conditions.

The calculations below specifically address SGTR event sequences involving a stuck open safety valve (other event sequences are discussed later). For these events, the staff considered the source of radioactive iodine (initial coolant activity and iodine spiking); primary to secondary transport; partition and water transport after leaving the secondary system; and meteorology using best estimates and conservative estimates for each of these items, as summarized in Table 8.

Table 8 Range of parameters considered

Parameter	Most conservative	Best-estimate value
Initial coolant activity	1 μCi/gm	0.1 μCi/gm
Iodine spiking	Design basis (500x for 2 hrs)	10 to 20% of design basis
Primary to secondary iodine transport	---	Best estimate calculations
Partition (and plateout) in SG	1.0	1.0
Partition and water transport after leaving SG	1.0	1.0 (iodine held in water, water transported in small droplets)
Meteorology (χ/Q) for site dose calculations	1×10^{-3}	2×10^{-4} (average meteorology)
Meteorology for estimating health effects	---	Best estimate CRAC code calculations

The bases for the estimates given in Table 8 are discussed below.

Initial Iodine Activity

The Standard Technical Specifications (STS) limit the primary coolant activity to 1 μCi/gm. Although some plants have higher limits and some exceed the STS value for a short period of time, the 1 μCi/gm appears to be a reasonable upper limit for an initial value. The NRC report on fuel performance, "Fuel Performance Annual Report for 1981," NUREG/CR-3001, was consulted to determine how frequently the 1 μCi/gm value was exceeded. The staff found that 9 PWRs exceeded the limit on one or more occasions for a total of 33 times. However, in every case, the limit was only exceeded for a short period of time. The highest steady-state operating value was approximately 0.5 μCi/gm. The best estimate value of 0.1 μCi/gm was chosen as representative of a plant operating with several failed fuel rods. Although many plants run with lower coolant activity, some operate with values 2 to 5 times the best-estimate value.

Iodine Spiking

The range of iodine spiking was assumed to vary from 10% to 20% of the design-basis spike (best-estimate assumption) to 100% of the design-basis spike of 500 times the steady-state iodine-production rate for two hours following a reactor trip. To establish a best estimate-value, primary coolant activity values were calculated as a function of time following a reactor trip using various assumptions about the size of the iodine spike. The calculated increase in iodine concentration was then compared to the iodine spikes reported in the Fuel Performance Annual Report for 1981 (NUREG/CR-3001). Although there is considerable variation from event to event and some uncertainty about exactly when the post-trip samples were taken, it appears that an iodine spike of 10% to 20% of the design basis spike is consistent with operating experience.

Primary-to-Secondary Iodine Transport

The transport of iodine from the primary system to the steam generator was calculated with a best-estimate time-dependent (finite difference) code which accounts for dilution by ECCS, mixing in the RCS, leakage to the SG, radioactive decay, cleanup (letdown and SG blowdown), partition, carryover to the condenser, feedwater addition and release to the atmosphere.

Partition in the Steam Generator

For event sequences 1, 4A, and 4B involving an SGTR followed by SG overfill, and a subsequent stuck open-safety valve, the assumption of no partitioning (i.e., PF = 1.0) represents the best estimate for these conditions (NUREG/CR-2659).

For event sequences 9A, 9B, and 9C involving a stuck open safety valve followed by blowdown of the steam generator and rupture of one or more tubes, the effective partition factor will depend on whether the steam generator water level is above or below the rupture location(s). If the rupture(s) is not covered by water, then all primary liquid leaking into the secondary flashes into steam before it has a chance to mix with the secondary water. Thus, for uncovered tube ruptures, no partitioning (PF = 1.0) is assumed in the steam generator. For purposes of assessing non-core-melt releases, the staff has conservatively assumed the tube rupture location to be uncovered.

Partition and Water Transport After Leaving the Steam Generators

The blowdown of a steam generator through a stuck-open safety/relief valve will be in the form of a two-phase mixture of steam and water droplets. The size of the water droplets during a high-pressure blowdown is expected to be small (10 μm) based on drop size predictions made for LOCA blowdown conditions (Gido, R. G., and A. Koestal, 1978). A mixture with such small droplets resembles a fog or mist. For the expected range of weather conditions, droplets of such a small size would be expected to stay in suspension in the atmosphere and be carried away from the point of release. An analysis of iodine released during a steam line break with a concurrent steam generator tube rupture supports this conclusion (NUREG/CR-2659). In that analysis, the retention on site of liquid released from the steam generator was neglected partially based on containment system experiments. These experiments showed that only approximately 20% of the mass of water exiting from the break into the atmosphere was retained close to the point of discharge.

Meteorology

The range of χ/Q values in Table 8, which were used to calculate site boundary doses, represent the range from best-estimate conditions to typical FSAR 95% meteorology. The best-estimate value was chosen to represent average conditions for a typical site. The offsite health effects (mean, latent deaths) were calculated with the CRAC code. These were best-estimate calculations for the Byron site and were done in the same manner as for Final Environmental Statement reports.

Results

Table 9 summarizes the consequences of non-core-melt SGTR sequences involving a stuck-open steam generator safety valve. Table 10 summarizes the probabilities of these events and the corresponding public risk. SGTR sequences involving steamline breaks (event sequences 2, 5A, 5B, 8A, 8B, and 8C), stuck-open MSIVs (sequences 3, 6A, and 6B), and intentionally opened MSIVs (sequences 7A and 7B) will also cause radiological releases, but are not dominant contributors to the risk from non-core-melt releases. SGTRs occurring in conjunction with a main steamline break have consequences similar to those indicated in Table 9 for event sequences 9A, 9B, and 9C, but occur at a lesser frequency. SGTR events involving an open MSIV (whether accidental or intentional) involve relatively minor releases associated with the release of noble gas from the condenser, and possible release of steam through the auxiliary feedwater pump turbine.

The site boundary doses in Table 9 are based on accumulated doses at the site boundary over 6 hours. Thus, these doses are not directly comparable to the 10 CFR Part 100 limits, which are based upon accumulated dose for 2 hours immediately following onset of the postulated fission-product release. For event sequence 1, the 2-hour site boundary doses are approximately 20% of the 6-hour values given in Table 9. For event sequences 9A, 9B, and 9C, the 2-hour site boundary doses are approximately 60% of the 6-hour values given in Table 9 for single and multiple tube ruptures.

It can be seen that with best estimate assumptions on initial coolant iodine concentration, iodine spiking, and meteorology, the offsite boundary doses are

Table 9 Consequences of non-core-melt SGTR sequences involving a stuck-open SG safety valve

Sequence		I-131 release[1]/ event (Ci)	Site-boundary dose[2,3]/event (rem)
1	Single SGTR + overfill + SV stuck open	106-4445	10.6-2223
4A	2-10 SGTRs + overfill + SV stuck open	130-5500	13-2750
4B	≥ 10 SGTRs + overfill + SV stuck open	130-5500	13-2750
9A	Stuck-open SV + 1 SGTR	122-5150	12-2600
9B	Stuck-open SV + 2-10 SGTRs	131-5600	13-2800
9C	Stuck-open SV + ≥ 10 SGTRs	133-5650	13-2800

[1]Range associated with best estimate and conservative estimate assumptions on initial coolant iodine activity and iodine spiking.

[2]Range associated with best estimate and conservative estimate assumptions on initial coolant iodine activity, iodine spiking, and meteorology.

[3]Accumulated doses at the site boundary over 6 hours.

small compared to the consequence limits of 10 CFR Part 100. However, if unfavorable assumptions are made regarding these parameters, the 2-hour offsite boundary doses may challenge or exceed these guidelines.

The risk estimates in Table 10 are very small and are based on the best-estimate parameters given in Table 8. Events involving worst case values of these parameters are expected to occur at a much lower frequency than the overall frequency of SGTR events involving a stuck open safety valve (i.e., 4.9×10^{-4}/RY for B&W plants and 2.3×10^{-4}/RY for W and CE plants) shown in Table 10 and, therefore, are not expected to be dominant contributors to the risk from non-core releases.

Table 10 Summary of probabilities and risks from non-core-melt SGTR sequences involving a stuck-open safety valve

Sequence		Probability (RY)	Risk of latent fatality deaths/RY
1	Single SGTR + overfill + SV stuck open	1.9×10^{-4}	2.4×10^{-7}
4A	2-10 SGTRs + overfill + SV stuck open	4×10^{-5}	6.2×10^{-8}
4B	$\geq$ 10 SGTRs + overfill + SV stuck open	1×10^{-6}	1.6×10^{-9}
9A	Stuck-open SV + 1 SGTR	1.3×10^{-4}*	1.9×10^{-7}*
9B	Stuck-open SV + 2-10 SGTRs	1.3×10^{-4}*	2.1×10^{-7}*
9C	Stuck-open SV + $\geq$ 10 SGTRs	2.5×10^{-7}*	4.0×10^{-10}*
	Total (W, CE plants)	2.3×10^{-4}	3.0×10^{-7}
	(B&W plants)	4.9×10^{-4}	7.0×10^{-7}

*Estimates for sequences 9A, 9B, and 9C are applicable to B&W plants only.

3.7 Conclusions

The foregoing risk analysis carried out by the staff leads to the following conclusions:

(1) Although there are significant uncertainties inherent in the staff's analyses, the analyses contain a number of conservatisms to minimize the potential for grossly underestimating risk.

(2) The staff's analyses indicate that the core-melt probability from all SGTR-related causes is small, about 5.3×10^{-6}/RY for B&W plants and 3.9×10^{-6}/RY for W and CE plants. These probabilities are a relatively small fraction (10% or less) of the overall probability of core-melt events from all causes based on probabilistic risk assessments that have been performed for a number of PWRs. The corresponding risk to the public is estimated to be limited to 2.4×10^{-3} (B&W plants) and 1.7×10^{-3} (W and CE plants) latent fatalities/RY and 4.6×10^{-6} (B&W plants) and 4.3×10^{-6} (W and CE plants) early fatalities/RY from SGTR accidents associated with core melt based on calculations performed for a representative PWR site (Byron).

(3) SGTRs occurring in conjunction with a non-isolatable loss of secondary system integrity can lead to significant offsite releases (comparable to NUREG-75/014 PWR release categories 8 and 9), even if core melt does not

occur. The probability of SGTRs occurring in conjunction with a stuck-open safety valve is estimated to be 4.9×10^{-4}/RY for B&W plants and 2.3×10^{-4}/RY for W and CE plants. Site-boundary doses would typically be expected to be small relative to the consequence limits of 10 CFR Part 100 based on best-estimate assumptions regarding coolant iodine activity concentrations, iodine spiking, and meteorology. The use of conservative assumptions regarding these parameters leads to site-boundary dose estimates which may challenge or exceed the 10 CFR Part 100 limits; however, the frequency of such doses is significantly less than the above 2.3×10^{-4} to 4.9×10^{-4}/RY estimate. The staff estimates public risk from non-core-melt releases to be very small: about 7×10^{-7} latent fatalities/RY for B&W plants and 3.0×10^{-7} latent fatalities/RY for W and CE plants.

(4) On the basis of the staff and SAI evaluations of the risk from SGTR accidents, as discussed above, the staff finds that SGTR events beyond the design basis do not contribute a significant fraction of the early and latent cancer fatality risks associated with other reactor events at a given site. Furthermore, the risk assessment indicates that the increment in risk associated with SGTR events is a small fraction of the accidental and latent cancer fatality risks to which the general public is routinely exposed.

4 NRC STAFF ACTIONS AND COMPLETED ITEMS

4.1 Introduction

This section includes a discussion of those issues identified by the staff in 1982 (following the SGTR event at Ginna) as warranting further staff action or study. This includes a description of the initial bases and concerns leading to consideration of these actions and the current status of these actions. Table 11 provides a summary listing of these actions and their status.

These NRC staff actions have been designated as Generic Issue 67. A prioritization evaluation of these staff actions has been performed and incorporated into NUREG-0933, "Prioritization of Generic Issues," Supplement III. Resolution of these actions is being monitored by the staff's Generic Issue Management Control System (GIMCS).

A number of the staff actions involve broad generic issues extending beyond issues strictly related to steam generators. These include staff actions shown in Table 11 which relate to "Organizational Response" and which have been completed. These also include actions which are being addressed as part of other existing regulatory programs such as "Pressurized Thermal Shock" (USI A-49), "Improved Accident Monitoring" (NRC Generic Letter 82-33), "Reactor Vessel Inventory Measurement" (TMI Task Action Plan (TAP) II.F.2, NRC Generic Letter 82-28), "Guidance on Reactor Coolant Pump Trip" (TMI TAP II.K.3.5, NRC Generic Letter 82-33), "Control Room Design" (TMI TAP I.D.1, NRC Generic Letter 82-33), and "Improved Emergency Operating Procedures" (TMI TAP I.C.1, NRC Generic Letter 82-33). Completion of these broad generic tasks is considered to be outside the scope of the staff's integrated program to resolve "Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity."

The remaining staff actions identified in Table 11 involve other issues related to steam generators. As noted in the table, a number of these remaining staff actions are relatively low priority tasks which will remain inactive pending completion of higher priority tasks and availability of staff resources. Others of these remaining staff actions, as indicated in Table 11, are actively being pursued as part of Generic Issue 135, "Steam Generator and Steam Line Overfill Issues," and/or the Steam Generator Group Project/Steam Generator Tube Integrity Program (SGGP/SGTIP) sponsored by the NRC Office of Nuclear Regulatory Research. In view of the low risk estimates associated with SGTR events, the staff concludes that the resolution of USIs A-3, A-4, and A-5 is not contingent upon completion of these tasks. However, these tasks will help ensure that risk continues to be low and may lead to proposals for revising existing regulatory guidance and possibly requirements concerning steam generator tube inspections and repairs, revisions to the Standard Review Plan concerning the design basis SGTR, and resolution of the steam generator/steam line overfill issue. The potential safety benefit and cost of implementation will be assessed for any proposals stemming from these activities. If justified by this cost/benefit analysis, additional or revised regulatory guidance or requirements will be issued.

Table 11 NRC staff actions and completed items

Report section	Subject	Action	Status
4.2	Steam Generator Integrity		
4.2.1	Steam Generator Tube Sleeves	Develop SRP guidance for review of tube sleeving	Note 1
4.2.2	Inservice Inspection Program for Denting	Develop denting inspection program	Note 1
4.2.3	Improved Eddy-Current Techniques (ECT)	Develop improved ECT requirements	Generic Issue 135 SGGP/SGTIP
4.2.4	Category C-2 ISI Requirements	Upgrade existing requirement	Generic Issue 135 SGGP/SGTIP
4.3	Plant Systems Response		
4.3.1	Steam Generator Overfill	Determine potential for and consequences of SG overfill	Generic Issue 135
4.3.2	RCS Pressure Control During an SGTR	Determine optimized pressure control procedures	USI A-45, TMI TAP II.D.1
4.3.3	Pressurized Thermal Shock Program, A-49	Consider Ginna information in generic USI A-49 program	USI A-49
4.3.4	Improved Accident Monitoring	Address Ginna experiences by implementing RG 1.97 programs	Regulatory Guide 1.97 Program, Generic Ltr. 82-33
4.3.5	Reactor Vessel Inventory Measurement	Observation: Ginna information supports need for TMI TAP II.F.2 program	TMI TAP II.F.2, Generic Ltr. 82-28

See footnote at end of table.

Table 11 (Continued)

Report section	Subject	Action	Status
4.4	Human Factors Considerations		
4.4.1	Reactor Coolant Pump Trip	Issue requirements pursuant to TMI TAP II.K.3.5 program	TMI TAP II.K.3.5, Generic Ltr. 82-33
4.4.2	Control Room Design Review	Consider Ginna information in TMI TAP I.D.1 reviews	TMI TAP II.D.1, Generic Ltr. 82-33
4.4.3	Emergency Operating Procedures Improvement	Consider Ginna information in generic TMI TAP I.C.1	TMI TAP II.C.1, Generic Ltr. 82-33
4.5	Radiological Consequences		
4.5.1	Reassessment of Radiological Consequences Following a Postulated SGTR Event	Reassess potential radiological consequences	Note 1
4.5.2	Reevaluation of Design-Basis SGTR	Reassess adequacy of design basis SGTR	Generic Issue 135
4.5.3	Secondary-System Isolation	Reassess provisions for isolating the affected steam generator	This task has been dropped
4.6	Organizational Response		
4.6.1	Operations Center Communications and Notification	Improve coordination and communication by issuance of procedures and other actions	Complete

See footnote at end of table.

Table 11 (Continued)

Report section	Subject	Action	Status
4.6	Organizational Response		
4.6.2	Interaction Between Regional Base Teams and the Executive Team	Improve coordination between teams	Complete
4.6.3	NRC Site Team--Location of Site Team Components and Public Affairs Information Flow	Improve team deployment and the role of the Public Affairs Office	Complete
4.6.4	Familiarization With NRC Response Plan	Provide training	Complete
4.6.5	Alternate Evacuation Routes and Sites	Ensure that alternates are included in licensees' plans	Complete
4.6.6	Deescalation of Emergency Classification	Issue the needed guidance on deescalation plans and procedures	Complete by CY-89
4.6.7	Offsite Dose Assessment	Issued needed guidance on offsite dose assessment methods	Complete

[1]Not-high priority tasks. Completion of these tasks will be scheduled commensurate with the priority nature of the work and the availability of staff resources.

4.2 Steam Generator Integrity

4.2.1 Steam Generator Tube Sleeves

Task

NRC should develop guidance governing the design, installation, and inspection of steam generator tube sleeves. The guidance should be presented in a revision of the Standard Review Plan (NUREG-0800) and should include the following criteria:

(1) Sleeves Intended To Repair Defective Tubes

(a) Sleeves shall be designed in accordance with ASME Code requirements to act as the primary pressure boundary. The design shall be based on the assumption that all original defects in the sleeved tube have penetrated completely through the wall of the tube.

(b) Criteria for inspection of sleeved tubes shall be consistent with criteria for unsleeved tubes.

(c) Criteria for plugging tubes with degraded sleeves shall provide the same margins of structural and mechanical integrity as those of RG 1.121 for unsleeved tubes.

(d) Sleeves shall be designed so that potential leakage from all installed steam generator tube sleeves during normal operating conditions shall be limited to the rate set in the Technical Specifications. Leakage during postulated accidents shall not result in offsite doses exceeding a small fraction of limits set in 10 CFR Part 100.

(e) The potential for wear and/or accelerated corrosion at the joints of tubes and tube sleeves shall be included in the materials selection and design evaluation of tube sleeves.

(2) Tube-Stiffening Sleeves

(a) Criteria for inspection of sleeved tubes shall meet those of RG 1.83 and the Standard Technical Specifications (STS) for unsleeved tubes.

(b) Potential for wear and/or accelerated corrosion at joints between tubes and tube sleeves shall be included in the design and evaluation of tube sleeves.

Initial Basis for Consideration

For severely degraded steam generators, a large number of tubes may be removed from service as a result of tube plugging. This reduces the available primary-to-secondary heat transfer surface and may ultimately force a decrease in the rated output of the plant. Some utilities faced with the prospect of derating power have elected to replace the degraded steam generators. Such replacement, however, requires an extended outage and involves considerable cost to the utility and its customers. To prolong the life of severely degraded steam generators, some utilities, with NRC approval, have elected to repair defective

tubes with tube sleeves. The advantage of sleeving over plugging is that the repaired tube remains functional, reducing both the loss in heat transfer area and the increase in primary coolant flow resistance.

The tube sleeving procedure involves inserting a tube of smaller diameter (sleeve) inside the tube to be repaired. The sleeve is positioned to span the defective portion of the original tube and is then either hydraulically or mechanically expanded above and below the defective region. The expanded joints are sometimes brazed to ensure additional leaktightness. Tube sleeving repairs have been performed to restore primary coolant boundary integrity on straight accessible portions of tubing degraded by wastage, intergranular attack, and stress-corrosion cracking.

Sleeves were first used at Palisades in 1976 and 1977 when approximately three dozen sleeves were installed in tubes that had been degraded by wastage.

In 1980 and 1981, more than 6000 sleeves were installed in the San Onofre Unit 1 steam generators to repair tubes degraded by caustic stress-corrosion cracking. Sleeving programs have more recently been conducted at Indian Point Unit 3, Point Beach Units 1 and 2, Ginna, and Millstone Unit 2.

Applicable regulations governing the design, installation, testing, and inservice inspectability of sleeves include General Design Criteria (GDC) 14, 15, 31, and 32 of 10 CFR Part 50, Appendix A. However, there are no generic regulatory guidelines for implementing these regulations. To date, the NRC staff has reviewed and approved steam generator tube sleeving programs on a plant-specific basis. The staff anticipates numerous additional proposed sleeving programs in the coming years. Criteria for the design, installation, testing and inspection of steam generator tube sleeves are necessary to ensure adequate and uniform implementation of the General Design Criteria.

In addition, such criteria can ensure that any previous difficulties with sleeves (e.g., sleeve and tube degradation as a result of inadequate braze procedures and controls) are recognized and appropriately accounted for in future programs. The criteria should be included in a revision to the Standard Review Plan.

Status

This task is not expected to result in a significant reduction in public risk, but has been classified as a regulatory impact issue based on reduced industry and NRC costs (NUREG-0933, Supplement III). This task will be scheduled pending the availability of staff resources, after assigning resources to approved high- and medium-priority generic issues.

4.2.2 Inservice Inspection Program for Denting

Task

The NRC staff should propose a denting inspection program for inclusion in the Standard Technical Specifications (STS). The program should include criteria for establishing the scope of the inspections and acceptance criteria (i.e.,

denting limit based upon tube restriction or strain) including the following elements and definitions:

(1) gauging or profilometry inspection of any tube that restricts passage of the standard size eddy-current probe (__dia.)* as a result of denting

(2) gauging and profilometry inspection of any tube that restricted passage of the standard size probe (__dia.)* during a previous inspection as a result of denting or that exhibited more than (__%)* strain if profilometry inspections were performed

(3) criteria for gauging or profilometry inspection of additional tubes based on the results of initial inspections

(4) appropriate plugging limits for dented tubes

(5) for Westinghouse steam generators

   (a) criteria beyond which visual inspection of the support plate flow slots for potential deformation ("hourglassing") shall be performed

   (b) requirement to plug all row 1 tubes if detectable flow slot deformation ("hourglassing") is observed, unless it can be directly verified that the upper support plate flow slots are undeformed

Initial Basis for Consideration

At present there is no specific mention in Regulatory Guide 1.83 and there are no specific requirements in the Standard Technical Specifications (STS) to inspect tubes for denting.

Operating experience has shown that surveillance of tube denting is necessary to preclude development of stress-corrosion cracking induced by denting. There has been one instance (Surry Unit 2 in 1976) in which denting led to high stresses in the U-bend region resulting in an SGTR. Plant-specific criteria have been established for plants with extensive denting; however, generic criteria have not been developed. Generic criteria would ensure that minimum standards for denting inspections are available for application as needed.

Status

This task is not expected to result in a significant reduction in public risk, but has been categorized as a regulatory impact issue since it would produce a small reduction in risk and would provide a net cost benefit to the industry and to the NRC (NUREG-0933, Supplement III). This task will be scheduled pending the availability of staff resources, after assigning resources to approved high- and medium-priority generic safety issues.

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*To be determined.

4.2.3 Improved Eddy-Current Techniques

Task

The staff should evaluate, in parallel with ongoing ASME Boiler and Pressure Vessel (B&PV) Code activities, improved eddy-current test programs for incorporation into the ASME B&PV Code, Section V for NDE and Section XI for Inservice Inspection.

Initial Basis for Consideration

The need for this task was identified as a result of staff consideration of specific proposals for improved eddy current test procedures as discussed in Section 2.3 of this report.

Status

This task is being addressed as part of a much broader program sponsored by the NRC Office of Nuclear Regulatory Research (RES); namely the Steam Generator Integrity Program/Steam Generator Group Project. This task is also being tracked as part of NRC Generic Issue 135, "Steam Generator and Steam Line Overfill." A detailed overview of the objectives, scope, and status of the RES program is presented in NUREG-0975, Vol. 5. This program includes a number of elements pertaining to eddy current testing. These include evaluation and development of advanced eddy current test methodologies and a detailed assessment of the capabilities of currently used and developmental eddy current methodologies to reliably detect, characterize, and size flaws in steam generator tubing. Results from these studies are being used to assess needed changes to ASME B&PV Code requirements and Regulatory Guide 1.83 concerning eddy-current testing. Topical reports detailing results and recommendations stemming from this program are expected to be published before the end of calendar year 1988.

4.2.4 Category C-2 Inservice Inspection Requirements

Task

The NRC staff should investigate more practical alternatives to the originally proposed potential requirement concerning "Supplemental Tube Inspections" which is discussed and evaluated in Section 2.2.1.

Initial Basis for Consideration

Section 2.2.1 identified a number of limitations in the existing Technical Specification requirement for steam generator tube inspections when Category C-2 results are found during initial inspection sampling. The staff considered a potential industry action (Section 2.2.1) which addressed these limitations, but which was found to lead to potentially significant costs. The staff should investigate actual industry practice relative to the staff's concerns and practical alternatives to the staff's initial proposal for improved supplemental tube sampling inspection practices which could be implemented on a case-by-case basis as needed.

For reasons discussed in Section 2.2.1.3, this task is not expected to result in significant reductions in risk. However, effective steam generator tube inspection programs are an important element of an effective overall program to ensure steam generator tube integrity.

Status

This task is being addressed as part of a much broader program sponsored by the NRC Office of Nuclear Regulatory Research (RES); namely the Steam Generator Integrity Program/Steam Generator Group Project. This task is also being tracked as part of NRC Generic Issue 135, "Steam Generator and Steam Line Overfill." A detailed overview of the objectives, scope, and status of the RES program is presented in NUREG-0975, Vol. 5. As part of this program, the reliability of steam generator inspection programs is being evaluated as a function of inspection frequencies and tube inspection sample sizes. Results from these studies are being used to assess needed changes to Regulatory Guide 1.83 concerning steam generator inspections. Topical reports detailing results and recommendations stemming from this program are expected to be published before the end of calendar year 1988.

4.3 Plant Systems Response

4.3.1 Steam Generator Overfill

Task

The NRC staff should select a small number of PWRs representing the PWR spectrum of designs and determine the potential for and consequences of steam generator overfill. Further NRC or licensee actions should be determined on the basis of this and other studies discussed in Sections 4.3.2, 4.5.1, and 4.5.2.

Initial Basis for Consideration

During the Ginna SGTR, the affected steam generator filled up to the steamline safety valve as a result of primary-to-secondary leakage from continued operation of the safety-injection pumps. The safety valve lifted five times at successively lower pressures and failed to fully reseat (at least twice). The failure to completely reseat contributed to the overfill problem by lowering the pressure in the damaged steam generator, thus raising the differential pressure across the broken tube and sustaining the leakage despite reduced primary system pressure. The probability of steam generator overfill can be reduced by improved emergency procedures. However, there are no programs or systems that can ensure that the steam generator will not overfill during future steam generator tube ruptures.

Failure of the valve to close could provide a direct pathway for the release of radioactive primary water to the environment (releases at Ginna were very small for the reasons cited in Section 2.9.2). This sequence of events (i.e., steam generator overfill followed by a stuck-open safety valve) is beyond the design basis for SGTR events in SRP 15.6.3 to establish that the radiological consequences meet 10 CFR Part 100.

In addition, given the potential for overfill, the integrity of the steam lines under combined loads from excessive water mass in the steam lines and possible waterhammer should be investigated and confirmed.

Status

This task is being performed as part of NRC Generic Issue 135, "Steam Generator and Steam Line Overfill Issues." The staff expects to issue a report describing the results of this effort by the end of calendar year 1988.

4.3.2 Reactor Coolant System Pressure Control During an SGTR

Task

The NRC staff should evaluate whether further improvements should be made by owners of PWRs, emphasizing the use of existing plant systems and equipment, to control and reduce reactor coolant system (RCS) pressure following an SGTR in order to stop primary-to-secondary leakage within the time frame assumed in the final safety analysis report (FSAR). The spectrum of possible initial conditions, RCS thermal-hydraulic conditions, and break sizes should be considered. The use of the pressurizer auxiliary spray system should be explicitly examined because its use may eliminate the need to use the pressurizer power-operated relief valve (PORV) in cases in which forced RCS flow has been lost. The study should address the following objectives: (1) minimizing the primary-to-secondary leakage through the broken steam generator tube; (2) maximizing control over system pressure; and (3) minimizing the chances of producing voids in the RCS and other complicating effects.

Initial Bases for Consideration

Without forced reactor coolant flow, which may occur as a result of reactor coolant pump (RCP) trip or a loss of offsite power, the necessary RCS depressurization following an SGTR is more difficult because of the loss of normal pressurizer spray. RCS fluid contraction caused by the cooldown from the dumping of steam to either the condenser or to the atmosphere will result in some reduction in RCS pressure, but other measures must be taken to expeditiously reduce the RCS pressure to the point at which flow into the damaged steam generator stops. The pressurizer PORV was used during the Ginna and Prairie Island SGTR events to reduce RCS pressure. However, it is difficult to control pressure with the PORV because its use creates an additional loss of coolant. The decrease in pressure can be so rapid that the steam voids may be formed in the upper vessel head and in the top of the U-tubes, further complicating the depressurization. Formation of voids can lead to concerns about core cooling. The Ginna operators were sufficiently concerned that they left the safety injection pumps operating, thereby overfilling the steam generator that had the ruptured tube and challenging the safety valve.

It is not apparent that the auxiliary spray from the charging system could have successfully lowered the RCS pressure to the point at which flow out the broken tube would have stopped. It may have been that, by spraying cold charging fluid into the pressurizer, the decrease in pressure would have resulted in void formation, thus expanding RCS fluid and filling the pressurizer, and rendering further spray flow ineffective. This phenomenon as well as the thermal stresses on the spray nozzle itself should be examined.

Status

The TMI Task Action Plan Item I.D.1, NUREG-0737, has within its scope the development of emergency operating procedures (EOPs) for accidents and transients, including SGTRs. Likewise, in the USI A-45 study, "Shutdown Decay Heat Removal Requirements," the staff is also developing and studying the adequacy of current and alternate means of satisfying LWR shutdown decay heat removal requirements. The USI A-45 study will also be looking into shutdown requirements imposed by SGTRs in PWRs. In its prioritization analysis in NUREG-0933, Supplement III, the staff concluded that the RCS pressure control issue is being addressed as part of these staff programs.

4.3.3 Pressurized Thermal Shock

Task

The difficulty in understanding the temperature transient experienced by the Ginna reactor vessel raises the question of the need for improved temperature monitoring in the cold leg and in the reactor vessel downcomer. This issue and the effects of RCS flow stagnation associated with the isolation of a steam generator should be addressed by the pressurized thermal shock program, A-49.

Initial Basis for Consideration

During the Ginna SGTR, the affected steam generator was isolated and the reactor coolant pumps were tripped. As a result, the flow in the B reactor coolant loop was reduced to a few hundred gallons per minute, while cold, high-pressure injection water was being injected into the loop. The cold-leg piping apparently experienced a cooldown of approximately 260°F in 30 minutes. The reactor vessel apparently did not experience this rapid cooldown, since the flow in the cold leg was in the reverse direction, that is, from the reactor vessel toward the steam generator. Other events, as discussed in NUREG-0916, resulting in steam generator isolation and continued safety injection could result in adding cold water to the reactor vessel.

Status

Studies of the probability, consequences, and resolution of such events are within the scope of the pressurized thermal shock (PTS) program, A-49. This program has resulted in promulgation of a PTS rule (10 CFR 50.61) on July 23, 1985 which (1) establishes a screening criterion related to the fracture resistance of pressurized-water-reactor (PWR) vessels; (2) require analyses and a schedule for implementation of neutron flux reduction programs that are reasonably practicable to avoid exceeding the screening criterion; and (3) require detailed safety evaluations to be performed before plant operation beyond the screening criterion will be considered. Guidance on meeting the requirements of the new PTS rule is provided by NRC Regulatory Guide 1.154 which was issued in January 1987. The NRC staff is monitoring implementation of this rule in Multiplant Action (MPA) A-21.

4.3.4 Improved Accident Monitoring

Task

The NRC staff should address accident monitoring weaknesses of the type observed at Ginna by implementation of Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident," and the safety parameter display system.

Initial Basis for Consideration

During the January 25, 1982 event at Ginna, several weaknesses in accident monitoring became apparent; these included (1) nonredundant monitoring of RCS pressure, (2) failure of the position indication for the steam generator relief and safety valves, and (3) the limited range of the charging pump flow indicator for monitoring charging flow during accidents. Each of these areas is specifically addressed in Regulatory Guide 1.97. Assuming that the guide had been implemented on the Ginna plant before the January 25, 1982 event, the monitoring of the event would have been substantially improved and there would have been more assurance of correct operator actions in response to the event. Improved accident monitoring also would have improved the NRC staff's ability to assess the plant status and the appropriateness of the licensee's actions and recommendations.

Status

This issue has been resolved by Multiplant Action Item A-17 (Instrumentation to Follow the Course of an Accident). The resolution was issued in Supplement 1 to NUREG-0737 (Generic Letter 82-33).

4.3.5 Reactor Vessel Inventory Measurement

Task

The staff has observed that the implementation of TMI Task Action Plan Item II.F.2, "Instrumentation for Detection of Inadequate Core Cooling," would have substantially improved the Ginna situation by ensuring that steam bubble formation in the upper head of the reactor vessel could have been more accurately monitored.

Initial Basis for Consideration

During the Ginna SGTR, the formation of a steam bubble in the reactor vessel upper head significantly complicated the course of the event. The uncertainty about the size of the steam bubble was a significant factor in the operators' decision to continue safety injection beyond the point when termination is called for in the emergency procedures.

Status

TMI TAP Item II.F.2 is being implemented as Multiplant Action Item F-26. Letters to individual licensees (Generic Letter 82-28) and orders to Babcock & Wilcox licensees and Arkansas Nuclear One, Unit 2 were issued on December 10, 1982.

4.4 Human Factors Considerations

Human factors tasks are being addressed by ongoing programs in the control room design review program (TMI Task Action Plan Item I.D.1), the emergency procedures review (TMI Task Action Plan Item I.C.1), and the reactor coolant pump trip criteria review (TMI Task Action Plan Item II.K.3.5).

4.4.1 Reactor Coolant Pump Trip

Task

The NRC staff should issue guidance for licensees regarding the development of reactor coolant pump (RCP) trip criteria that will ensure continued forced reactor coolant system (RCS) flow during steam generator tube breaks up to and including the design-basis tube rupture.

Initial Basis for Consideration

Under the scope of TMI Action Plan Item II.K.3 in NUREG-0660, the NRC Bulletin and Orders Task Force conducted generic reviews of the loss-of-feedwater and small-break loss-of-coolant events on all operating reactors. These reviews consisted of an evaluation of systems reliability analyses, guidelines for emergency procedures, and operator training related to these events.

As a result of these reviews, a number of recommendations for improvements were made and documented in NUREG-0565, NUREG-0611, NUREG-0623, NUREG-0626, and NUREG-0635. Included among these recommendations was the reevaluation of reactor coolant pump trip criteria.

The issue of reevaluation of reactor coolant pump trip criteria involves the potential improvement that might be achieved by establishing better criteria on when to allow the operation of reactor coolant pumps and when to trip them. It was believed that better criteria might allow the use of reactor coolant pumps to aid in recovery from certain transients while still ensuring that these pumps could be tripped during a small-break LOCA.

Analyses indicate that continued operation of the RCPs following a range of small-break LOCAs could lead to excessive inventory loss for which the high-pressure injection system would be unable to compensate. Generally, the range of break sizes of concern is from 0.02 to 0.2 ft^2 (2 to 5 in. equivalent diameter).

The interim position documented in NUREG-0623 requires manual tripping of the reactor coolant pumps when the symptoms of a small-break LOCA (i.e., a safety-injection signal and low RCS pressure) are present. Although the interim position appears to deal effectively with the problem of excessive inventory loss for the small breaks of concern, it also has an effect on other more likely events. During the Ginna SGTR, the tripping of the reactor coolant pumps was the direct cause of the steam formation in the upper head of the reactor vessel during RCS depressurization. The steam formation led the operator to question the adequacy of core cooling and to continue safety injection. This led to the steam generator being overfilled and to the repeated opening of the steam generator safety valve, producing radiological release to the atmosphere. The tripping of the reactor coolant pumps also eliminated the possibility of using the

normal pressurizer spray system to equalize the RCS and steam generator pressures. This led to the use of the pressurizer PORV, which subsequently failed open and had to be isolated.

Tripping the reactor coolant pumps during a tube rupture event is undesirable from the standpoint of managing the event, minimizing offsite radiological releases, and avoiding a more serious consequence.

Status

A resolution to this issue (TMI TAP Item II.K.3.5) was identified in NRC Generic Letters 83-10(a) through 83-10(f) issued on February 8, 1983, to all PWR licensees and applicants. The members of the W, CE, and B&W Owners Groups have submitted generic analyses to satisfy the requirements of Generic Letter 83-10. NRC Generic Letters 85-12, 86-05, and 86-06 provided the staff's evaluation of the Owners Group analyses. The utility for each plant is being required to submit plant-specific implementation information regarding the RCP trip criteria. With respect to the Westinghouse Owners Group (WOG) analyses, the staff concluded that although the WOG had developed acceptable criteria for tripping the RCPs during small-break LOCAs and to minimize RCP trip for SGTR and non-LOCA events, the proposed RCP trip criteria may provide only marginal assurance of preventing RCP trip for the design-basis SGTR event for plants with low-head HPI pumps. If a plant-specific analysis determines that the WOG alternative criteria are marginal for preventing unneeded RCP trip, the staff recommended that a more discriminating plant-specific procedure be developed.

4.4.2 Control Room Design Review (TMI Task Action Plan Item I.D.1)

Task

As a result of a review of the Ginna control room following the tube rupture, several items related to the event were identified that are contrary to good human factors engineering principles. These items, as described below (see Initial Basis for Consideration) have been reviewed by the staff. Each of these items has been covered in the work to be done for the Item I.D.1 control room reviews, thus assuring that these items will be factored into all Item I.D.1 control room design reviews.

Initial Basis for Consideration

(1) Rotary Functional Identification

This issue is based on the review of the power-operated relief valve (PORV) cycling activity described in NUREG-0909. The PORV rotary switches have discrete CLOSE, AUTO, or OPEN positions, but the associated block valve rotary switches located immediately to the right of each PORV switch are spring-loaded-return-to-center momentary-contact switches with CLOSE and OPEN positions. The switches appear identical. In addition, the full-stroke cycle of the block valve is approximately 40 seconds, and it is not obvious whether the spring-loaded switch must be held for the full cycle or not.

Rotary switches that appear identical but operate differently (e.g., spring-loaded momentary vs. discrete position) should be provided with unique

identifying features to indicate the operational differences. In addition, spring-loaded momentary-contact rotary switches that must be held by the operator in the activated position until the function is completed, versus activated and released (function continuous until complete), should also be provided with unique identifying features. Unique identifiers should be consistent throughout a control room.

(2) Indicator Lights Burned Out

The NRC task force reviewing the Ginna control room found that numerous indicator lights on the control room consoles had burned out, as was reported in NUREG-0909. This condition precluded an expeditious determination of equipment status.

Bulbs had burned out on both legend and nonlegend indicators. Since most nonlegend lights use a single bulb, indication was not available when the bulb was burned out. In addition, not all the bulbs were equally bright; the legend lights with dimmer bulbs were difficult to read. Apparently, the light intensity of the bulbs was related to age. If indicator lights are to be used to provide safety-system status information, they must operate properly.

Administrative procedures should be implemented that require a check, on a per-shift basis, of all indicator light bulbs in the control room except those that can only be tested by operating equipment (e.g., breaker controls). If the latter include multiple status (e.g., OPEN, CLOSED) in which each state is indicated by a light, a check should be made, on a periodic basis, to ensure that at least one light is illuminated. Failed bulbs must be replaced immediately.

As part of the detailed control room design review required by the TMI Action Plan, a survey should be conducted to determine the number of bulbs that can be power tested (e.g., push-to-test), have dual filaments, are long-life qualified, or are operated with reduced voltage. This information should be used as the basis for a study to determine what hardware changes can be made to produce a more reliable indicator light system and a more effective and efficient test capability.

(3) Inconsistent Terminology

During the review of the Ginna SGTR event, several examples of inconsistent use of terminology on the control panels and between the panels and the plant procedures were observed. For example, it was observed that steam generator appeared as "STEAM GEN," "STM GEN," and "S/G." In addition, terminology appearing on the panels was inconsistent with terminology appearing in procedures, and both were inconsistent with some commonly used terms. For example, the commonly used term "PORV block valve" appears on the control panel label as "PRESSURIZER REL. STOP VLV," and is referred to in the SGTR procedure as "PORV backup isolation valve." This type of inconsistency may cause confusion and may lead to operator error.

All terminology and initialisms used in control rooms and in procedures should be reviewed for standardization and consistency, and modified accordingly.

Status

The items identified at Ginna have been covered in the work to be done for the I.D.1 control room design reviews, thus assuring that these items will be factored into all I.D.1 control room design reviews. This recommendation will be resolved as part of Task I.D.1 "Control Room Design Review," required by NUREG-0737, and implemented as Multiplant Action (MPA) Item F-08.

4.4.3 Emergency Operating Procedures Improvement (TMI Task Action Plan Item I.C.1)

Tasks and Bases

The emergency operating procedures followed by the operators for coping with the Ginna SGTR event were basically sound. However, the NRC staff and plant personnel identified several areas as needing improvement. In addition, certain recommendations made in NUREG-0651 are also appropriate for further consideration. These items will be considered by the staff in conjunction with its ongoing work under TMI Task Action Plan Item I.C.1, "Short-Term Accident Analysis and Procedures Revisions." A discussion of each of these items follows:

(1) Reactor Coolant Pump Restart

Unambiguous guidance and criteria for RCP restart should be provided in emergency operating procedures (EOPs) for coping with an SGTR and other non-LOCA events. The guidance and criteria should be developed and updated recognizing the ongoing efforts to resolve the RCP trip issue, which is discussed in Section 4.4.1.

(2) Availability of Faulted Steam Generator Safety and Relief Valves

During the Ginna SGTR, operators misinterpreted a procedural step intended to place the faulted steam generator atmospheric dump valve (ADV) in its manual mode by appropriately positioning its control. Instead, the block valve was incorrectly closed, removing the ADV from service and forcing reliance on the safety valves to respond to overpressure conditions. During the event, the lowest set point safety valve opened five times.

Since safety valves will probably be required to pass mostly water instead of steam in the event the steam lines contain water, their reliability for reclosure at the desired lower pressure is questionable, and they may stick open. An SGTR with a stuck-open valve will allow relief from the primary to the secondary and to the atmosphere and can complicate core cooling.

Availability of the ADV avoids challenges to safety valves, and if the ADV sticks open it can be isolated to stop release to the atmosphere.

Plant-specific emergency operating procedures should, therefore, identify individually the appropriate valves for operation and make clear that remotely operated relief valves on faulted steam generators are not to be isolated but are to be made available for use.

(3) Multiple and Second-Order Failures

Emergency operating procedures (EOPs) should consider multiple failures and selected second-order failures. Task Action Plan Item I.C.1 requires that EOPs consider multiple failures, and the SGTR event has highlighted the need to ensure that actions to cope with multiple failures are specified in the procedures. For example:

(a) Safety valves in the faulted steam generators were challenged because the ADV was isolated and because safety-injection (SI) pumps pressurized the steam generator through the break to the opening set point. Instructions in EOPs could help mitigate this event (as discussed in the previous section).

(b) Multiple steam generator tube failures would compound the SGTR event. The leak is greater, the time required for isolation of the SG becomes crucial, the steam lines can be filled, and the potential for saturated conditions in the primary system may be greater.

(c) Inability to use the main condenser, coupled with the failure of the nonfaulted steam generator in a two-loop plant, can complicate residual heat removal.

(d) Inability to isolate the faulted steam generator can lead to increased offsite radiological release and can complicate core cooling.

Procedures for coping with these types of failures can significantly mitigate the consequences of an SGTR.

Some of the contingencies to be considered are plant specific; however, actions specified in EOPs will be supported by analyses.

(4) Steam Bubble Formation

Operating events resulting in the inability to isolate small breaks require that the reactor coolant system (RCS) be depressurized expeditiously to conserve inventory and minimize the release of radioactive coolant to the plant or environment. As a result of depressurization, steam can form in the RCS, particularly without a reactor coolant pump (RCP) in operation, so that the local metal temperatures could exceed the coolant saturation temperature. Steam bubbles can form, even with core exit thermocouples, and the installed subcooling meter can indicate that the RCS is subcooled. Furthermore, if the depressurization is not adequately controlled, the RCS pressure may drop to that corresponding to the saturation temperature and cause the bubble to grow.

Events such as an SGTR, RCP seal failure, and small-break LOCA requiring rapid depressurization of the RCS can result in the formation of a steam bubble. The emergency procedure for an SGTR at Ginna did not address steam bubble formation. Emergency procedures should cover this eventuality and provide guidance on identifying bubbles and on how to cope with and eliminate them.

(5) Cooling a Faulted Steam Generator

As a result of the tube rupture at Ginna, the faulted steam generator became overfilled and the written procedure in use did not address either cooling the steam generator or the precautions and care required for a steam line full of water up to the main steam isolation valve. The plant staff did develop, and management authorized, a cooldown method which involved several cycles of feeding the steam generator with unborated water, lowering the primary pressure, and causing backflow through the leak into the primary system. The plant staff was concerned with maintaining the integrity of the filled steam line and with how this portion of the plant should be cooled.

The bases for the PWR owners groups technical guidelines should contain an analysis of the effects that caused the steam generator and steam lines to fill, guidance to help prevent overfilling, and steps to cope with an overfilled steam generator. Alternative ways for cooling down the faulted steam generator should be covered in some of the guidelines.

The EOP must also provide guidance on boron dilution and reactivity control while cooling and diluting the RCS by any technique that allows unborated water to flow into the RCS. Instructions for sampling boron concentration or performing other determinations must ensure against any encroachment on the required reactivity shutdown margin.

(6) Cooling an Intact Steam Generator

The decision to secure the condenser and use only the atmospheric dump valve (ADV) relieving directly to the atmosphere during the Ginna event as the primary means of decay heat removal may have reduced some inplant equipment contamination; however, it added to offsite releases and removed the normal means of plant cooldown. Also, after cooling with the ADV had begun, the decision to break vacuum on the condenser removed the condenser as a backup means of energy removal should a problem have occurred with the intact steam generator's ADV or its control equipment. Licensees should evaluate the need for and consequences of securing the condenser as a means of removing energy from an intact steam generator and using only the atmospheric relief valve on the intact steam generator. The EOPs should be structured to minimize offsite releases and to avoid removal of backup heat removal equipment from service except when removal is necessary.

(7) Safety-Injection Pump Termination and Restart Criteria

The EOP used at Ginna contained criteria for stopping and restarting the safety-injection (SI) pumps. Although a subcooling margin was not specified, the operators' training and general knowledge equipped them with the understanding of the need for maintaining a subcooling margin, which they did. EOPs that specify the use of the SI pumps should address the desired subcooling margin or other appropriate indicators for stopping and restarting these pumps.

The EOP used at Ginna provided no guidance to make the operators aware of the likelihood of the formation of bubbles in the RCS, particularly when reactor coolant pumps were tripped as they were. Neither did it advise the operators

about how to cope with the large bubble that was formed when the PORV stuck open while they were trying to conduct a controlled depressurization. Because of these plant conditions, the operators did not stop the safety-injection pumps when they could have, and thus they pressurized the secondary side of the faulted steam generator through the break to a safety valve opening pressure, and it opened, releasing radioactivity to the environment.

After the safety-injection pumps were stopped and when preparing to start an RCP, an SI pump was restarted as a precaution against an anticipated large pressure transient that could collapse the bubble in the RCS. The large transient did not result, but again the faulted SG safety valve lifted.

Unambiguous guidance and criteria on safety-injection-pump operation and termination should be provided in the EOP for coping with an SGTR and a bubble in the RCS. These criteria should include a required subcooling margin to permit stopping and to require restarting.

(8) Procedure Format and Clutter

Important space in Ginna's EOPs was used up by nonrelevant instrument error determination and guidance for reporting offsite authorities. This kind of information should not be included in the caution or action portion of an EOP.

The NRC staff has prepared extensive guidance on the human factors element and has disseminated it in NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures."

(9) Criteria for Natural Circulation Determination

The desired means of core heat removal after tripping the RCPs is by establishing natural circulation. If cooling is not by natural circulation, then operators must confirm its existence and particularly under periods of abnormal RCS conditions such as the presence of a bubble other than in the pressurizer, it must be repeatedly confirmed. Ginna has a procedure to confirm existence of natural circulation, and training and licensing examinations cover this area. Other plants should also have procedures containing explicit criteria for determining natural circulation.

(10) Accommodation of Plant Differences From Reference Plant in Plant-Specific Emergency Procedure Development

The EOP generic technical guidelines for the most part are structured for a particular nuclear steam supply system design using a standard or typical plant. They also typically provide discussion, guidance, bases, and sample calculations for other designs to permit operators of those plants to have a smooth transition from the guidelines to plant-specific procedures. To illustrate the concern for accommodation of plant differences in transition from guidelines to plant procedures, consider Ginna, a two-loop plant with a small pressurizer compared with the large pressurizer in the four-loop plant. The Ginna RCS operates at 2200 psi, about the same as most four-loop plants, and its steam generator tubes are the same size as those in the four-loop plants. Thus, a large SGTR at Ginna would cause a leak of about the same magnitude as a similarly sized leak in a four-loop plant. This leak rate in a two-loop plant with a small pressurizer causes a much more rapid level and pressure decrease

than in the four-loop plant. Thus, the operator must respond more rapidly to have the same influence as an operator on a four-loop plant. Similarly, a failure in the non-faulted steam generator on a two-loop plant leaves no backup for core heat dissipation, but in a four-loop plant two SGs would remain for heat removal.

Plant-specific analyses should be performed to account for differences from the referenced plant.

(11) Rapid Determination of Faulted Steam Generator and Timely Depressurization of Reactor Coolant System To Minimize RCS Inventory Loss and Releases

Techniques should be developed to identify the damaged steam generator more rapidly, and these techniques should be included in the procedures and operator training.

Plant procedures should require timely securing of all feedwater to the damaged SG as soon as it is identified. The procedures may allow intermittent feeding of the SG should its water level require such action.

Procedures and operator training programs should emphasize the need to expeditiously secure steam flow from the damaged steam generator to the turbine-driven auxiliary feedwater pump (TD AFP). The TD AFP should not be started (manually) unless the damaged SG has been identified and isolated, and steam from that SG to the TD AFP has been isolated. If the TD AFP has been automatically started, it should be secured if the other AFPs are operating and adequate feed flow exists. If the steam to the TD AFP is known to be from an undamaged SG, there should be no significant releases in the turbine exhaust and, therefore, no reason to secure the TD AFP. As a minimum, running times should be logged to enable the determination of radioactive release amounts.

The timely depressurization of the plant should be emphasized in the plant procedures and in operator training. Every licensee should adequately emphasize this important facet of the SGTR. In addition, RCS subcooling should be emphasized in plant procedures and operator training.

(12) Main Steam Isolation Valve Closure During Plant Cooldown

Procedure and operator training programs should address a possible MSIV closure in the unfaulted loop(s) during the cooldown following a safety injection signal. The operator should be given corrective actions to implement immediately.

(13) Use of Charging and Letdown Systems

The emergency procedure should direct the operator to attempt to control the loss of RCS inventory caused by the SGTR by the use of charging and letdown systems and to initiate an orderly plant shutdown, if possible. Reactor trips from high-power conditions could easily lead to lifting of SG safety valves and/or ADVs and result in direct radioactive release to the environment.

If the decreases in pressurizer level and pressure are not controllable, then a manual reactor trip should be initiated before the indicated pressurizer level goes off scale (low). This item should be identified in the plant-specific procedures.

(14) Operation of Loop Isolation Valves

Plants with loop isolation valves should investigate the use of these valves following an SGTR and modify the plant procedures accordingly. Isolating the affected loop would almost immediately abate SGTR leakage, but may complicate plant cooldown. Licensees should, therefore, examine the advantages and disadvantages of loop isolation in their plant.

(15) Use of Power-Operated Relief Valve

If the PORV is required to control RCS pressure on loss of normal spray capability, guidance should be provided to the operator to monitor and control (if possible) the pressurizer relief tank parameters to minimize the potential of rupture-disk relief to containment.

(16) Potential Complicating Events

The operators should be provided with adequate procedural steps and training so that they can properly identify and correct the following situations during an SGTR:

(a) automatic opening of the pressurizer PORV(s) and/or the safety valves

(b) water solid or drained pressurizer

(c) saturation conditions in the RCS

These situations may be postulated to occur either before or after the operator intervenes.

(17) Site-Specific Operator Training

Operator training using site-specific procedures on other than site-specific simulators should be reviewed to determine whether the training received is realistic and practical. A determination should be made as to whether this training would enable the operator to relate the site-specific emergency procedures to the site-specific control boards and plant systems.

(18) Steam Generator Level Control for Combustion Engineering Plants

The suggested procedure for CE guidelines to reduce the level in the faulted steam generator by letdown through the blowdown system to a holdup tank should be investigated to see that it provides an adequate level of protection for all possible break flows.

Status

Some of the above items are explicitly included in the review requirements of TMI TAP I.C.1. Other items in the list are considered to be implicitly within the intent of TMI TAP I.C.1 in that the availability of systems under expected conditions (such as at Ginna) should be used in developing diagnostic guidance for operator and procedural development. The staff issued Generic Letter 82-33,

Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability," on December 17, 1982. This supplement restates the approved requirements and provides guidance on steps that have to be taken by licensees and the staff to accomplish this implementation. TMI TAP I.C.1 is being implemented as Multiplant Action (MPA) Item F-05.

4.5 Radiological Consequences

This section contains recommendations intended to reduce the potential radiological consequences of a steam generator tube rupture and to improve the ability to accurately measure the amount of radioactivity released from the plant.

4.5.1 Reassessment of Radiological Consequences Following a Postulated SGTR Event

Task

The NRC staff should reassess SGTR accidents to determine the effects of releases made for periods substantially longer and through release points other than those previously analyzed. These analyses should specifically address the assumptions in Standard Review Plan Section 15.6.3 (NUREG-0800) and address the costs and benefits of requiring revised analyses by licensees.

Initial Basis for Consideration

After the steam generator tube rupture at Ginna, plant equipment malfunctions and operator actions resulted in overfilling of the affected steam generator, which negated the ability of the moisture separators to retard the flow of fission products to the environment. In addition, the water level in the secondary system reached the steam line and water entered the inlet of the steam safety valves. This may have ultimately led one valve to fail to fully reseat. Such failures allow an uncontrolled release to the environment and prevent isolation of the affected steam generator.

As a result of these events, it can be concluded that operating procedures and plant response limitations may produce accidents different from those analyzed previously in which accidents were assumed to be terminated in approximately 30 minutes and proper water levels were maintained in the affected steam generators (no overfilling). For these reasons, the staff concludes that previous analyses of the offsite consequences of SGTR accidents may not include the full range of conditions that may result from operator actions at specific plants. Of primary concern are such factors as overfilling the affected steam generator, unanticipated relief valve releases, the accident duration, lack of liquid/gas phase iodine partitioning factors following overfilling and subsequent release of primary coolant in conjunction with iodine spiking, and primary coolant activity levels prior to such accidents.

Status

This task will provide a better understanding and means to assess future SGTR events in operating plants relative to the consequence limits in 10 CFR Part 100

and has been categorized as a licensing issue (NUREG-0933, Supplement III). This task will be scheduled pending the availability of staff resources, after assigning resources to approved high- and medium-priority issues.

4.5.2 Reevaluation of Design-Basis SGTR

Task

The NRC should consider, in conjunction with the tasks identified in Sections 4.3.1 and 4.5.1 of this report, the necessity of reclassifying or redefining the design-basis SGTR. The consideration should be based on observed aspects of SGTRs that may be outside the bounds of the analyses currently required. The consideration should include, but not necessarily be limited to, the following items: steamline flooding, stuck-open pressurizer PORV, steam formation in the reactor vessel head, leaking steamline safety valves, steam line and steam line support integrity under water-filled static and dynamic loading conditions, liquid rather than gaseous releases, criteria for terminating safety injection, inadvertent isolation of steam lines, release of reactor coolant outside containment, and single-failure assumptions.

The staff should evaluate the lack of an explicit statement in the Standard Review Plan (SRP) regarding reliance on safety-grade equipment on single failures along with a loss of offsite power. Other issues which should be considered include (1) whether it is appropriate to consider SGTR events involving more than a single ruptured tube, and/or SGTR events occurring as a consequence of a postulated MSLB or LOCA, (2) whether or not the loss of offsite power at some time after the identification of the event should be assumed, and (3) whether or not the offsite dose consequences must meet limits set in 10 CFR Part 20 rather than in 10 CFR Part 100.

Initial Basis for Consideration

The general basis for this recommendation is derived from the number of SGTRs that have occurred and the potential existing for SGTR doses exceeding the guidelines of 10 CFR Part 100. However, these doses would occur only if there were an unlikely, but not impossible, set of circumstances as discussed in detail in Section 8.1 of NUREG-0916. In any event, it is considered prudent to reconsider the SGTR event and the SRP assumptions and criteria.

The specific basis for consideration of the assumption of loss of offsite power (LOOP) derives from a concern regarding whether or not a LOOP at some time after the initiation of an SGTR may place a more severe requirement on systems and operators than a LOOP that is concurrent with the SGTR.

Status

This task has been categorized as a licensing issue (NUREG-0933, Supplement III) and will be resolved as part of NRC Generic Issue 135, "Steam Generator and Steam Line Overfill Issues." The staff expects to issue a report of its findings by the end of 1988.

4.5.3 Secondary-System Isolation

Task

The NRC staff should reevaluate the provisions for isolating the steam generators in conjunction with the tasks identified in Sections 4.3.1 and 4.5.1 of this report. The evaluation should consider whether the current provisions for isolating the main steam and feedwater lines are adequate, with particular emphasis on isolation of the steam generator with RCS loop isolation valves, using closed-bonnet secondary safety valves, or containing the discharge from the steam generator safety and relief (atmospheric dump) valves.

Status

This task has been ranked as a low-priority safety issue (NUREG-0933, Supplement III). Staff effort on this specific issue is not planned unless found to be warranted as a result of staff actions identified in Sections 4.4.3 and 4.5.1.

4.6 Organizational Response

This section discusses actions taken or to be taken by the NRC staff that are related to matters discussed in NUREG-0909. Some of the following items do not result in additional requirements for further actions but do report the results of efforts taken in response to the Ginna event that have been completed or are not applicable as a generic task.

4.6.1 Operations Center Communications and Notifications

Task

Corrective actions, in response to the issues discussed below under "Bases" have been taken by the Office of Inspection and Enforcement (IE) relative to the NRC Operations Center. Steps include improving coordination and communication of Operations Center, regional office, and resident inspector response by providing implementing procedures. The use of an additional telephone line has been considered and was tried in a recent drill. In addition, the Telecommunications Branch of the NRC has an ongoing contract with Calculon, Inc. to study upgrading the emergency communications system.

Bases

The results of assessments made during the Ginna event by the Region I base team and the NRC headquarters teams were not directly coordinated, and the communications between the resident inspector and the Region I base team were not always tied into the NRC Operations Center. The health physics network, the Federal Telecommunications System, and commercial telecommunications systems functioned adequately; the emergency notification system (ENS) link was only marginally acceptable. Some problems encountered were attributable to the number of phones off the hook and to background noise in the room where the phones were located (e.g., Region I's Incident Response Center); other problems arose because of the phones' locations in relation to essential sources of information (e.g., continuous midband frequency noise, intermittent high-pitched tones,

and unexplained breaks interrupted communications on the ENS lines). The staff of the NRC Headquarters Operations Center failed to make some notifications in a timely manner.

Status

The task has been completed. The results of this task will be implemented on a continuing basis.

4.6.2 Interaction Between Regional Base Teams and the Executive Team

Task

The NRC, pursuant to NUREG-0845, should improve coordination between the regional base team and the executive team.

Bases

The conversations between the NRC Chairman and the Governor of New York and his representatives indicated a lack of communication between the Region I Base Team Radiological/Environmental Protective Measures Manager and the executive team on NRC recommendations to the State of New York on field monitoring. The Chairman should have been briefed better on the State of New York's capabilities and existing monitoring systems before he spoke to the Governor.

Status

NUREG-0845 (Chapter III, Items I.4, J.4, and K.4) requires that all activities conducted by technical teams be coordinated with the site team. Continued participation by headquarters and regional base teams in exercise and training sessions for implementing NUREG-0845 will improve this coordination. This matter will be evaluated by the IE response coordination team in all future exercises in which IE and regional offices participate. Results of exercises will be documented by IE in the exercise report.

This task has been completed. The results of this task will be implemented on a continuing basis.

4.6.3 NRC Site Team--Location of Site Team Components and Public Affairs Information Flow

Task

Upon arrival at the airport, if a site area or general emergency classification exists, the NRC Site Team should be split, with the Public Affairs Coordinator going to the emergency news center, the State liaison officer and environmental/protective measures personnel going to the near-site emergency operations facility (EOF), and the rest of the initial site team going to the technical support center (TSC). As soon as possible, communication links should be established by the NRC personnel between the news center, EOF, TSC, base team, and Headquarters Operations Center.

The role of public affairs needs significantly improved definition, especially since NRC observations and information from headquarters, the regional office, and the site may be relayed to the same individual. These recommendations must assume that a public affairs individual cannot gather and disseminate information simultaneously. With this in mind, the improvements needed for an effective public affairs program are as follows:

(1) The Regional Public Affairs Manager (RPAM) should be located in the Incident Response Center (IRC) so that information concerning the event can be gathered by visually observing status boards and by questioning the Base Team Leader. If this is not possible, a dedicated communicator or runner must be provided to brief the RPAM not only on all of the information received but also on the significance of that information.

(2) Upon arrival at the site, the Public Affairs Coordinator should be dispatched to the emergency news center to coordinate the release of NRC information to the public. Communications must be established between the Public Affairs Coordinator and the site team leader as well as the counterpart public affairs individuals in headquarters and in the regional IRC.

(3) All information released to the public from any location (site, regional office, or headquarters) should be coordinated so that all public affairs individuals are aware of what information is being released.

Bases

The bases for this task are problems experienced in deployment of NRC regional staff as discussed in NUREG-0909, Section 6.4.2.2.

Status

Regional supplements and Revision 1 to NUREG-0845 have been published specifying procedures for improved deployment of the site team. The matter will be implicitly reviewed as a part of the regional participation in exercises. Results of exercises will be routinely documented in the IE exercise report.

This task has been completed. The results of this task will be implemented on a continuing basis.

4.6.4 Familiarization With NRC Response Plan

Task

Sufficient training should be provided to all NRC personnel likely to be involved in the implementation of the response plan to ensure familiarity with the plan and the associated procedures.

Bases

As discussed in NUREG-0909, Section 6.4.22, several examples of problems within NRC (confusion with the ENS and health physics network, failure to use IRC documentation forms, excessive noise in the IRC, and unavailability of public

affairs officers for prearranged briefings with the site team leader) may be indicative of a lack of familiarity with the NRC emergency response plan and procedures. NUREG-0845 was generally followed, although it had not been formally implemented and the indoctrination training had not been conducted at the time of the Ginna event. NUREG-0845 is new and fairly detailed so that all NRC response personnel would benefit from additional training.

Status

Training is being conducted to ensure improved emergency response. The matter will be implicitly reviewed as a part of the NRC staff's participation in exercises. Results of the exercises will be routinely documented in the staff's exercise report.

This task has been completed. The results of this task will be implemented on a continuing basis.

4.6.5 Alternate Evacuation Routes and Sites

Task

The NRC staff should inspect the implementing procedures of the licensee's emergency plan to ensure that they include plans for alternate evacuation routes and sites to preclude evacuating personnel into a contaminated plume.

Bases

As discussed in NUREG-0909, Section 6.1.2, during the Ginna event nonessential plant personnel were evacuated to an area, part of which was within the plume released from the plant because of the wind direction. This resulted in some slight contamination of personnel, mainly on their clothing.

Status

10 CFR Part 50.47(b)(10) requires licensees to provide a range of protective actions for emergency workers and the public. Section J.2 of NUREG-0654 depends on this regulation to include provisions for evacuation routes and transportation for onsite individuals to suitable offsite locations including alternatives for adverse radiological conditions. The Office of Inspection and Enforcement Inspection Procedure 82202, "Protective Action Decisionmaking," requires that inspectors verify annually that licensees can assess an accident and make recommendations for protective actions consistent with 10 CFR 50.47(b)-(10) and NUREG-0654, Section J.

This task has been completed. Results of these inspections are documented in inspection reports.

4.6.6 Deescalation of Emergency Classification

Task

The NRC staff should evaluate the need for developing and issuing to licensees generic guidance regarding the licensees' deescalation of emergency classification.

Bases

On the basis of the Ginna experience (see NUREG-0909, Section 6.1.1), specific plans and procedures addressing the technique for an orderly deescalation of the emergency response could have improved the selection of a plant status classification that more accurately described the condition of the plant in the recovery phase. The process of deescalation of emergency classification has not been addressed in NRC rules or in published criteria such as NUREG-0654. NUREG-0654 does address general plans for recovery and reentry, but does not provide generic guidance for deescalation. NUREG-0845 discusses the NRC procedures for deescalation.

Status

The staff, in coordination with the Federal Emergency Management Agency, intends to incorporate guidance on this matter as part of an upcoming proposed revision to NUREG-0654. Completion of this task has been delayed until 1989, pending completion of other higher priority work.

4.6.7 Offsite Dose Assessments

Task

The NRC staff should standardize the NRC method of assessing offsite doses and evaluate the need to make the assessment method available to all licensees.

Bases

Although the staff has concluded that the licensee's evaluation of the offsite doses during the Ginna event was, in general, consistent with the staff's evaluations (see NUREG-0909, Section 6.5.6), the staff has found that during licensee/NRC exercises, considerable effort was spent by the site team and the headquarters protective measures analysis team in resolving differences between licensee and NRC dose estimates. Confusion is created and NRC credibility diminishes when substantively different estimates are presented to State and local officials responsible for issuing orders on protective measures.

Status

The staff has developed an interactive rapid dose model for use by headquarters and the regions and has provided the model and portable computer equipment and training to all regional personnel. In addition, the staff is conducting regional workshops with State, licensee, and regional personnel on dose assessment and its role in protective action decisionmaking to ensure that all

response personnel understand both the reasons for differences in dose projection made during accidents and their importance.

This task has been completed. The results of this task will be implemented on a continuing basis.

APPENDIX A

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APPENDIX B

EVALUATION OF SGTR EVENTS FOR PRIOR PERIODS OF VULNERABILITY TO RUPTURE UNDER POSTULATED MSLB ACCIDENT

Each of the four U.S. plants which have experienced SGTRs to date experienced a limited period, prior to the SGTR, during which it was vulnerable to rupture under a postulated MSLB involving a peak primary-to-secondary pressure differential of 2600 psid. Each of these periods of vulnerability was terminated after the degradation of the steam generator tubing had progressed sufficiently far to cause rupture under normal operating conditions involving primary-to-secondary pressure differentials of about 1300 to 1500 psid. Staff estimates concerning the duration of these periods of vulnerability are provided below:

(1) R. E. Ginna Nuclear Power Plant

The failure sequence leading to the SGTR on January 25, 1982, involved impingement damage induced by a foreign object, plugging of degraded or leaking tubes, and breakage of previously plugged tubes with subsequent damage to adjacent plugged and unplugged tubes (NUREG-0909, NUREG-0916). This sequence of events is believed to have been occurring since about 1975.

The tube that ruptured in January 1982 had been inspected in April 1981, but no indication was recorded for this tube at that time. A reevaluation of April 1981 data performed subsequent to the SGTR event in January 1982 revealed that the subject tube actually exhibited an absolute eddy current (EC) indication in April 1981 which was interpretable as a 40% indication utilizing a uniform wear scar calibration standard. At the time of the rupture, Ginna had accumulated 6.3 reactor operating months since April 1981. NRC-sponsored burst tests of steam generator tubing (NUREG/CR-0718) indicate that wall penetrations of 75% and 88% are necessary to cause rupture during an MSLB and during normal operating conditions, respectively. Assuming an 88% penetration at the time of rupture and a linear penetration rate, the amount of penetration would have exceeded 75% for 1.7 reactor operating months. This represents the period of time during which the subject tube could have been vulnerable to rupture during a postulated MSLB.

Eddy-current inspection performed after the rupture event revealed no additional tubes sufficiently degraded so as to be vulnerable to rupture during an MSLB. Thus, a postulated MSLB during the 1.7 reactor operating months prior to the January 1982 rupture would have resulted in no more than a single tube rupture.

Another tube was plugged with an 80% EC indication in April 1981. The degradation mechanism is believed to be the same as that which caused the January 1982 rupture event. No other tubes with similar indications were found. Assuming no EC measurement error, and assuming the same rate of

degradation as for the tube that eventually ruptured, the staff estimates that this tube could have been vulnerable to rupture during a postulated MSLB for a period of 0.7 reactor operating months before it was plugged. If the EC error is considered and the assumption is made that the tube was degraded to just short of 88% (the point at which it would have ruptured during normal operation) at the time it was plugged, then the period of vulnerability would have been 1.7 months.

Additional tubes were plugged between 1976 and April 1980 as a result of EC indications and leaks attributed to the degradation mechanism described above. There is no direct evidence that any tubes experienced periods of vulnerability (to rupture during MSLB) during this time. However, uncertainties exist in this regard in view of possible large eddy-current measurement errors sometimes associated with long-wear scars and because of the uncertainty regarding the residual strength of tubes that leaked during normal operation. The staff has accounted for this uncertainty by assuming that one additional reactor month of vulnerability existed between 1976 and April 1980.

In summary, the staff conservatively estimates that Ginna has experienced 4.4 reactor operating months during which it may have been vulnerable to rupture during a postulated MSLB. There is no direct evidence that Ginna has ever operated during a period of vulnerability to multiple ruptures. Any such period would have occurred between 1976 and April 1980 and would likely have been of very short duration (< 1.0 month).

(2) Prairie Island, Unit 1

The SGTR at Prairie Island Unit 1 on October 2, 1979 was the result of excessive wear caused by a foreign object rubbing against the tube (NUREG-0651). The staff has assumed that rupture occurred when the wear had penetrated 88% through the wall thickness. The foreign object is believed to have been introduced during sludge lancing performed in the spring of 1976. Assuming that the wear degradation began then, and assuming a linear wear penetration rate, and considering that 31 reactor months elapsed between spring 1976 and October 1979, the staff estimates that the wear exceeded 75% of the wall thickness for 4.7 reactor operating months. Thus, 4.7 months represents the period during which Prairie Island Unit 1 may have been vulnerable to an SGTR as a consequence of a postulated MSLB.

Investigations performed after the SGTR event of October 1979 indicated that no additional tubes were potentially vulnerable to rupture in the event of a postulated MSLB.

(3) Point Beach Unit 1

The Point Beach rupture on February 26, 1975 is believed to have occurred only after a crack had penetrated entirely through the tube wall and had grown sufficiently long to permit bursting. For calculational purposes, the staff has assumed that one tube was uniformly thinned to 88% throughwall (at the time of rupture) and that rupture could have occurred during an MSLB at 75% throughwall.

The flaw is believed to have initiated at a high growth rate in September 1974 during an on-line conversion from phosphate to all-volatile treatment (AVT) secondary water chemistry. The staff has assumed that the tube was already degraded 50% throughwall in September 1974 either as a result of cracking or wastage. On this basis and the assumption that 5.5 reactor operating months elapsed between September 1974 and February 26, 1975, the staff estimates that the idealized flaw exceeded 75% throughwall penetration for 1.9 months prior to rupture during normal operation.

There is no direct evidence that Point Beach was vulnerable to multiple tube ruptures under postulated MSLB conditions before the February 1975 SGTR. Subsequent to the event, a sizable number of tubes were found to contain indications in excess of 90% throughwall. Experience has shown that cracks will generally produce small detectable leaks before degrading tube integrity enough to potentially rupture during normal operating or postulated accident conditions. However, sufficient uncertainties surround this event so that the staff cannot entirely dismiss the possibility that a limited period of vulnerability to multiple failures under postulated MSLB conditions occurred. Such a period, if it existed, would have been less than the 1.9-month period during which Point Beach was vulnerable to a single tube rupture for a postulated MSLB.

(4) Surry Unit 2

Surry Unit 2 experienced an SGTR on September 15, 1976 as a result of stress corrosion cracking in the U-bend (NUREG-0651). The staff does not have enough information to estimate the period during which this unit may have been vulnerable to rupture under postulated MSLB conditions. Subsequent investigation revealed cracks in other tubes; however, a limited period of vulnerability to multiple tube failures under postulated MSLB conditions may or may not have existed.

Based on the above, the staff has concluded that Ginna, Prairie Island Unit 1, and Point Beach Unit 1 together have operated for a total of 11 months during which they were vulnerable to an SGTR as a consequence of a postulated MSLB. Assuming that Surry Unit 2 experienced a period of vulnerability equal to the average period experienced by the three plants above, the total period of vulnerability experienced by these four plants was 1.2 years.

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This report presents the results of the NRC integrated program for the resolution of Unresolved Safety Issues (USIs) A-3, A-4, and A-5 regarding steam generator tube integrity. A generic risk assessment is provided and indicates that risk from steam generator tube rupture (SGTR) events is not a significant contributor to total risk at a given site, nor to the total risk to which the general public is routinely exposed. This report also identifies a number of staff-recommended actions that the staff finds can further enhance the effectiveness of licensee programs in ensuring steam generator tube integrity and in mitigating the consequences of an SGTR. As part of the integrated program, the staff issued Generic Letter 85-02 encouraging licensees of pressurized water reactors (PWRs) to upgrade their programs, as necessary, to meet the intent of the staff-recommended actions; however, such actions do not constitute NRC requirements. In addition, this report describes a number of ongoing staff actions and studies involving steam generator issues which are being pursued to provide added assurance that risk from SGTR events will continue to be small.

The staff concludes that with final publication of this report, USIs A-3, A-4, and A-5 are technically resolved.

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