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Evaluation of Steam Generator Tube Rupture Events

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Office of
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ABSTRACT

The NRC Staff's review of three domestic pressurized water reactor steam generator tube rupture events has shown that no significant offsite doses or systems performance inadequacies have occurred. The plant operators and systems successfully avoided direct releases to the environment (via the steam generator power operated relief valves or safety valves) and brought the reactor to a safe shutdown condition. However, a number of relatively minor procedural and equipment deficiencies were noted.

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EVALUATION OF STEAM GENERATOR TUBE RUPTURE EVENTS

1. INTRODUCTION

The purpose of this report is to evaluate the systems response, operator action, and radiological consequences of actual steam generator tube (SGT) rupture events. Three have occurred on domestic Westinghouse pressurized water reactors (PWRs): Point Beach Unit 1, Surry Unit 2, and Prairie Island Unit 1. Two SGT rupture events have occurred on foreign PWRs: Doel Unit 2 (Westinghouse) and Cadarache. In the three domestic PWR SGT rupture events, the offsite doses, plant systems, and operator responses were not unacceptable. Evaluations of the foreign reactors could not be completed because of insufficient information.

The report comprises several sections and appendixes. Following this introduction, Section 2 presents the conclusions resulting from review of the SGT rupture accidents that have occurred at three domestic PWRs. Next, Section 3 offers recommendations for correcting the deficiencies noted in the evaluations. A brief description of the typical behavior of a PWR during an SGT rupture is provided in Section 4.

Sections 5 and 6 present plant-specific information that briefly describes the actual occurrences, the mechanisms that resulted in the ruptured tubes, as well as the licensee's corrective actions.

Detailed plant evaluations follow in Section 7. The predicted plant response according to the final safety analysis report (FSAR) is compared with the actual operating experience for each affected system, such as the reactor coolant system (RCS) or the safety injection system (SIS), to determine whether the FSAR analysis is bounding, and whether the systems responded as expected. Operating procedures and actual operator actions are compared to determine any training or procedural inadequacies. The radiological consequences of each event are assessed to ensure that limits were not exceeded. Finally, comparisons are made among the plants to highlight similarities and significant differences in the plant responses to SGT rupture events.

Appendix A contains a general FSAR-type analysis of an SGT rupture event in a PWR. Appendix B contains detailed event sequences of each of the domestic SGT rupture events. Appendix C contains a description of SGT failure mechanisms, operating histories, and remedial actions taken at each of the three sites.

Appendixes D through F describe operations of and calculations for pertinent systems during SGT rupture events. Appendix G compares the design and operation of these systems.

Detailed accounts of the Doel Unit 2 and Cadarache events are not included in the body of the report since the available information is insufficient for an equivalent assessment. These reactors are located in Belgium and France, respectively. They are mentioned in this report because they are PWRs that have suffered SGT rupture events and, therefore, are the sources of additional data on PWR system response and radiological consequences during these events. Appendix H provides a summary of the Doel Unit 2 experience. As additional data on this event and the event at Cadarache become available, they will be evaluated by the staff.

The staff recognized early that SGT leaks and ruptures were potentially serious events that should be included in the safety analysis.

At the times Point Beach Unit 1, Surry Unit 2, and Prairie Island Unit 1 were licensed, there were no specific analysis requirements for SGT rupture events. However, the staff did conduct reviews of the analyses to verify that the risks to public health and safety were acceptably low.

Subsequently, standard review plans (SRPs) for review of safety analysis reports (SARs) were developed to provide guidance for staff review. These plans describe the review procedures and acceptance criteria for each postulated accident and transient. Section 15.6.3 of the SRP covers the SGT rupture event. The basic acceptance criterion is that the resultant doses be less than a small fraction of 10 CFR 100 exposure guidelines for single SGT ruptures. The staff does not require the analysis of multiple tube ruptures.

An SGT rupture accident as postulated in SRP Section 15.6.3 is classified as a Condition IV event by Westinghouse; that is, a limiting fault. The postulated sequence of events is not expected to occur during the plant life but is analyzed because the potential radiological consequences may be serious.

The staff does not require licensees to analyze loss-of-coolant accidents (LOCAs) concurrent with an SGT break, but does require all LOCA analyses to include the effects of the plugged tubes on reduced RCS flow. Recent studies have shown that as few as 10 tubes would need to have ruptured during a LOCA (assuming a leakage rate of 130 gal/min per ruptured tube) before the cladding temperature would be significantly affected (i.e., peak cladding temperature (PCT) > 2200°F).

Also, the staff has not required the SAR to include calculations regarding the main steam line break (MSLB) accident to assume concurrent rupture of any SGTs. However, the staff is presently studying the systems and offsite doses that would occur if an MSLB should cause rupturing of a varying number of SGTs.

The staff reviewed the the SGT rupture analysis documentation for Point Beach Unit 1, Surry Unit 2, and Prairie Island Unit 1 and determined that for each plant, its FSAR represents the analysis of record. Therefore, the FSAR analyses were used by the staff in its review of the three SGT rupture accidents.

2. CONCLUSIONS

Staff evaluation of the three domestic SGT rupture accidents resulted in the following conclusions:

(1) The arrival rate of SGT rupture events appears to exceed that projected for this event when it is classified as a limiting fault in SARs. The accident experience to date, however, indicates that more mild scenarios actually occur than those typically assumed in the plant SARs, and the radiological consequences have been very small.

(2) The FSAR descriptions of the behavior of the systems during an SGT rupture accident lack the specific details needed to make in-depth comparisons with the actual SGT ruptures that have occurred. The FSAR analyses for Point Beach and Prairie Island were especially deficient in quantitative details, requiring the staff to calculate certain of the parameters necessary for effective review.

(3) The conservative assumptions in the FSAR analyses resulted in leak rates in excess of those that have actually occurred. In this respect, the FSAR analyses bounded the actual events. However, the analyses did not include the radioactivity release path from the affected steam generator (SG) through the turbine-driven (TD) auxiliary feedwater pump (AFP) and out to atmosphere.

    In two events, Point Beach Unit 1 and Prairie Island Unit 1, the steam for the TD AFP was taken from the SG with the damaged tube. This resulted in direct releases to the atmosphere via turbine exhaust. In fact, this path for Point Beach Unit 1 gave a significant fraction of the overall release.

    The staff noted in its review of plant emergency procedures that definite actions regarding these release paths were not specified.

(4) The Nuclear Regulatory Commission (NRC) Inspection and Enforcement (I&E) Bulletin 79-06A, dated April 14, 1979, in response to the Three Mile Island Unit 2 (TMI-2) accident states that if the high-pressure injection (HPI) system has been automatically actuated because of low-pressure condition, it must remain in operation until either--

    (a) Both low-pressure safety injection pumps (LPSIPs) are in operation and flowing for 20 min or longer at a rate that would assure stable plant behavior; or

    (b) The HPI system has been in operation for 20 min, and all hot- and cold-leg temperatures (T_H and T_C, respectively) are at least 50°F below the saturation temperature T_{SAT} for the existing RCS pressure. If 50°F subcooling cannot be maintained after HPI cutoff, the HPI shall be reactivated. The degree of subcooling beyond 50°F and the length of time HPI should be in operation shall be limited by the pressure/temperature considerations for the vessel.

The FSAR analyses for an SGT rupture event state that the operator must take control of the HPSIPs to reduce system pressure and that the RCS pressure is to be equal to the damaged SG pressure within about 30 min after the event.

If the SGT break size is small and the HPSIPs are relatively high head pumps, then the RCS repressurization (following safety injection system (SIS) actuation) will be rapid. The RCS pressure could reach the setpoint of the pressurizer power-operated relief valve (PORV). During the Surry Unit 2 event, after SIS actuation, the RCS pressure and pressurizer level rose rapidly. The operators secured one HPSIP, and pressure and level dropped.

If the PORV opened to relieve pressure, the pressurizer liquid level would increase because of the HPI flow into the RCS. Eventually, the pressurizer could become filled with water, depending on break size, HPSIP characteristics, and other plant parameters. Therefore, it is not apparent that all plants suffering SGT ruptures would be able to reduce RCS pressure to the damaged SG pressure within 30 min, without stopping the HPSIPs before the required 20 min. During the Prairie Island Unit 1 event, the HPSIPs were left operating for 20 min, the PORV was manually opened to reduce pressure, and pressurizer level remained below the indicating range. However, the Prairie Island Unit 1 HPSIPs are relatively low head pumps, and the break was relatively large. The staff's 20-min requirement has been subsequently modified and now depends, to a large extent, on RCS subcooling.

Westinghouse has recently given all members of its Owners Group suggested procedural guidelines for securing HPSIPs after automatic safety injection (SI) actuation, and these have been implemented. The effects of HPSIP characteristics and SGT break size on the operator's ability to successfully reduce RCS pressure must be examined.

(5) Generally, the primary plant systems have responded in an anticipated manner during the SGT rupture events, considering the break size, system volumes, and individual system operating characteristics. The RCS depressurization and calculated leak flow rates are consistent. The staff calculated that even if the operator had diagnosed the problem immediately, started all charging pumps, and isolated letdown, the actual leak rate at Surry Unit 2 and Prairie Island Unit 1 were such that automatic reactor scram on low pressurizer pressure P_p could not be averted.

The SIS performed as expected when called on during the Surry Unit 2 and Prairie Island Unit 1 events. During the Point Beach Unit 1 event, the SIS was only intermittently used to aid in pressurizer level L_p control during system cooldown and was not automatically initiated.

(6) Generally, the secondary systems responded in an anticipated manner although the staff noted that an unanticipated automatic closure of the SG "B" main steam isolation valve (MSIV) occurred at Prairie Island Unit 1. On further investigation, it was found that the logic for automatic MSIV closure on each of the two-loop plants (Prairie Island Unit 1 and Point Beach Unit 1) was different than the logic for other

plants. Neither the licensee nor the staff could conclusively determine the cause for the MSIV closure. However, the staff believes that the automatic closure could have resulted from a high steam flow signal coupled with the SIS actuation and the low average RCS temperature T_{AVE}. The plant emergency procedures do not address this possibility. The staff could not determine whether the FSAR analyses assume this interruption of steam flow.

(7) The condenser air ejector radiation monitor provided early indication of each SGT rupture accident, although the Prairie Island Unit 1 operators were misled by the intermittent sound of an air ejector radiation alarm. Nevertheless, this sure indication of a large primary-to-secondary system leak did not appreciably contribute to an early diagnosis of the accident by the operators. In the Point Beach Unit 1 and Prairie Island Unit 1 accidents, this early indication was virtually ignored until the pressurizer pressure and level instrumentation confirmed a loss of primary coolant. This overreliance on pressurizer instrumentation may be attributable, in part, to operator training emphasis, as noted in the various investigations of the TMI accident. Several additional factors can be identified. At Point Beach Unit 1, the air ejector monitor quickly saturated, resulting in a "low" indication. In addition, poor design and maintenance of the SG blowdown monitors failed to confirm the SGT rupture and contributed to skepticism about the validity of the air ejector monitor reading. Similarly, no diagnostic information was received from blowdown instrumentation during the Surry Unit 2 and Prairie Island Unit 1 accidents. It is apparent that the reliability of the radiation monitoring system (RMS) was such that essentially no credibility was given to radiation instruments that responded to the SGT rupture condition. Poor or improper design, lack of or inadequate maintenance and calibration, and lack of operator training in the interpretation of radiation instrument response are all factors that appear to have contributed to this condition.

Another serious shortcoming of the RMS identified for all plants investigated is the lack of monitors at all identified release points such as the SG atmospheric dump valve (ADV) and the steam to the auxiliary feedwater (AFW) turbine.

Another potential release pathway that is not monitored is the secondary coolant, which may be substantially contaminated with fission products from the primary-to-secondary system leakage. This pathway includes turbine building and other building sumps and drains, vents and drains on various holdup tanks, and discharges from condensate polishing systems.

(8) The determination and isolation of the damaged SG appears to be taking longer than assumed in the FSAR analyses. This has not resulted in any significant increase in releases because the RCS activities during the three events were relatively low, and the operators have monitored the SG pressures.

(9) The depressurization of the RCS following the reactor shutdown was not done in an expeditious manner. The FSAR analyses for the three plants state that for the design base SGT rupture accident, the RCS and damaged

SG pressures should be essentially equal within about 30 min after the event. In Section 7.4 the staff shows that there are numerous means available to depressurize the RCS following the SGT rupture accident, but in all three actual events, the equalization time exceeded 30 min.

By maintaining the RCS pressure above that assumed in the FSAR analyses, the leakage to the damaged SG continues longer. Whether the integrated leakage exceeds that assumed in the FSAR depends on the actual break size and the actual RCS depressurization.

Although the actual depressurization times all exceeded the FSAR assumed values, only during the Point Beach Unit 1 event did the integrated leakage become a problem. Apparently, the level in the damaged SG rose to the point where filling the steam lines became possible. The pressure in the damaged SG rose as the increasing water level compressed the steam volume (the MSIV was closed), and the MSIV bypass valve had to be opened to reduce the damaged SG pressure. Point Beach Unit 1, however, did not isolate feedwater to the affected SG until 10 min after the MSIV was closed. It is not clear how much of an impact this had on the high water level in the faulted generator.

The staff agrees that a slow and careful RCS pressure reduction avoids stresses on the system and is less likely to result in the RCS approaching saturation condition. However, a slow RCS pressure reduction may, without careful operator attention, result in opening of the damaged SG ADV or safety valve (SV). The resulting offsite doses could be significantly greater than those experienced.

As a result of review of the TMI-2 event, the staff is requiring all PWRs to install RCS "saturation meters" that measure and indicate the degree of RCS subcooling. These devices should significantly aid the operator in performing an orderly RCS depressurization following an SGT rupture accident.

The staff noted that existing plant emergency procedures do not specifically direct the operator to avoid RCS saturation conditions, nor do they key the operator to perform a timely depressurization following an SGT rupture. (Westinghouse has subsequently developed new, post TMI-2, procedural guidelines for the SGT rupture accident. Adherence to these guidelines will (according to Westinghouse) reduce the possibility of the RCS becoming saturated.)

(10) Tripping the reactor coolant pumps (RCPs) following an SGT rupture accident eliminates the most desirable means of reducing RCS pressure--the normal pressurizer spray. Also, tripping the RCPs forces the system into a natural circulation mode of core cooling that may result in a smaller RCS subcooling margin because of the larger core ΔT (caused by the lower flow). In general, therefore, it is undesirable to force the RCS into natural circulation and to eliminate the preferred method of RCS pressure control.

However, recent staff and vendor calculations have shown that under a variety of LOCA conditions, RCP trip times have significant impact on PCTs. The phenomena and analyses are presented in staff report NUREG-0623. As a result of these calculations, the staff is requiring licensees of all Westinghouse PWRs to manually trip all RCPs if after an automatic SI actuation, RCS pressure falls below a predetermined plant-specific pressure. This pressure depends on the SG SV characteristics, the primary-to-secondary system ΔP for decay heat transfer, and allowances for instrumentation accuracies. The staff is requiring similar actions for other PWR licensees.

During the Prairie Island Unit 1 SGT rupture accident, the RCPs were tripped after automatic SI actuation because of an NRC requirement. However, with the new requirement (i.e., SIS + RCS pressure below about 1500 psig), the operators may not have to trip the RCPs following an SGT rupture because RCS pressure may remain above the required trip value.

If the RCPs are tripped because of SI actuation and a low RCS pressure condition, then the normal pressurizer spray is lost and the RCS is forced into a natural circulation mode of cooling. These losses may affect the operator's ability to reduce RCS pressure to the damaged SG pressure within 30 min after the event.

If the RCPs are tripped, then the pressurizer PORV would be used for RCS pressure control; however, the procedures currently in effect do not reflect the use of the PORV following RCP trip, nor do they direct the operator's attention to the pressure relief tank (PRT) pressure and level.

(11) The feeding of the damaged SG must be expeditiously stopped to avoid excessive SG level during the RCS cooldown. Because leakage into the damaged SG will continue until the pressure across the tubes has been equalized, the sooner feed flow to the damaged SG is stopped (after plant trip), the better the chance of avoiding overfilling the SG. Plant emergency procedures are not sufficiently explicit in this regard.

(12) At Point Beach Unit 1 the operators secured the RCP in the loop containing the damaged SG. This did not significantly reduce the flow from the ruptured tube nor increase the attainable RCS cooldown rate. In a two-loop plant, stopping an RCP reduces the spray flow available because each spray valve has a pickup tube just downstream from each RCP. The partial loss of spray reduces the depressurization rate, especially at relatively low RCS pressures.

During the Surry Unit 2 event, the RCP in the undamaged loop "B" was tripped. Tripping RCP "B" is part of the normal plant cooldown procedure and is done to reduce the total thermal input in an effort to improve the RCS cooldown rate. However, this action may have reduced the attainable RCS cooldown rate. Westinghouse has also stated that the operation of the RCPs in the intact loops enhances RCS cooldown rate. Surry Unit 2, being a three-loop plant, has pressurizer spray lines from Loops "A" and "C." Therefore, when RCP "B" is tripped, pressurizer spray flow is not affected.

(13) There is no problem with RCS boron dilution following the SGT rupture event. Once the RCS pressure is reduced to a level below that of the damaged SG, inleakage into the RCS via the ruptured SGT will occur. However, calculations show that even with the total contents of one SG assumed to be pure water, the RCS boron concentration remains acceptable, assuming adequate boron mixing. Westinghouse has pointed out that adequate boron mixing must not be automatically assumed and careful operator attention is necessary.

(14) Analysis confirms that the radiological consequences of the Prairie Island Unit 1 SGT rupture accident were small. (This conclusion could not be extended to the other two events because we had insufficient information to conduct analyses.) The small consequences experienced at Prairie Island Unit 1 are the result of the combined effects of the very short duration of the SG ADV actuation and a relatively low concentration of fission products in the primary coolant. However, calculations showed that there existed the potential for significantly larger releases if there had been a prolonged ADV or SV actuation on the affected SG. This could have occurred, depending on the actual RCS conditions (including the core decay heat and RCS flow, temperature, and pressure), under any one of the following conditions:

(a) If the operators had improperly identified the damaged SG, isolated the undamaged SG, and initiated atmospheric steam dump operations for the SG containing the ruptured tube

(b) If there had been a LOOP (loss of offsite power) early in the event when steam dump operation to the condenser from all SGs was in progress, before the identification and isolation of the damaged SG

(c) If the ADV or SV on the damaged SG had opened and remained open--the actuation of the ADV and/or SV during the SGT rupture event would occur if the reactor is tripped from a relatively high power level (this occurred during the Prairie Island Unit 1 event) or if an ADV actuation logic problem occurred

Accurate radiation monitoring instrumentation can reduce the probability of the operator making an erroneous identification of the damaged SG. Westinghouse states and the staff agrees that the RMS itself would not lead to more timely and accurate identification of the damaged SG, and that other instrumentation coupled with the RMS must be employed for this to be effective.

The SG ADVs have upstream isolation valves that could be used to stop flow from an ADV stuck in the open position if the operator has the necessary instrumentation to detect faulty ADV operation.

(15) The relatively low fission product concentration in the primary coolant of Prairie Island Unit 1 contributed to the small consequences of the event. In the absence of additional fuel failures, the radiological consequences of SGT rupture accidents are in nearly direct proportion to the primary coolant activity levels. As shown in Tables 8 and 9, the primary coolant I-131 equivalent concentration at Prairie Island Unit 1

was 25 nCi/g, and the resulting thyroid dose was 4.3 μrem. By comparison, a primary coolant concentration of 0.73 Ci/g was measured at the time of the Point Beach Unit 1 SGT rupture. This increase in primary coolant concentration would have resulted in a 30-fold increase in the offsite doses if the same SGT leak rate, ADV actuation, and air ejector discharge quantities occurred. This direct relationship between SGT rupture accident doses and primary coolant activity has been used to derive limiting primary coolant concentrations that, in the absence of additional accident-caused fuel failures, will assure that the resulting doses are a small fraction of the dose guidelines of reactor siting criteria 10 CFR 100. These limiting primary coolant concentrations have been incorporated into the Standard Technical Specifications. The Standard Technical Specifications for primary coolant activity have been adopted by the majority of PWR licensees (all but 10).

(16) In general, the style, detail, and format of the emergency procedures for SGT rupture vary considerably among the utilities reviewed because of different management approaches and different system designs. As a result, some procedures are more detailed in providing operator guidance and response, but all the procedures appear to be adequate to control an SGT rupture event.

(17) The radiological consequences of the three accidents reviewed in this report are concluded to be within the bounding analyses performed during the licensing process. However, the results of the staff's independent analysis of the Prairie Island Unit 1 accident indicate that the licensee may have substantially underestimated the resulting offsite doses. A lack of radiation monitors for the major airborne and liquid release paths prevents a verification of the estimated releases.

Staff analysis also indicates that the potential consequences of SGT ruptures that result in a release through the relief valves or SVs of the faulted SG (resulting from an incorrect accident diagnosis or unavailability of condenser steam dump capacity) could exceed those experienced to date by several orders of magnitude. These consequences can be limited, however, by maintaining appropriate limits on primary and secondary coolant fission product concentration. Such limits are included in the Standard Technical Specifications, which have been adopted by the majority of PWR licensees.

(18) The Point Beach Unit 1 incident was caused by tube wall thinning resulting from corrosion wastage associated with secondary water treatment with coordinated phosphates.

The Prairie Island Unit 1 incident was caused by tube wall thinning resulting from mechanical wear between the tube and a foreign object. It is, therefore, considered an isolated incident that has no significant generic implication, other than for the general quality assurance procedures for normal maintenance of SGs.

The Doel Unit 2 operators have defined stress corrosion cracking as the most probable cause of the June 1979 tube failure. The tube failure mechanisms in Surry Unit 2 and Doel Unit 2 incidents are therefore similar in nature although the stress state and the operating time associated with these failures are somewhat different. Hourglassing of the flow slots in the upper tube support plates existed when the U-bend tube failure occurred at Surry Unit 2. In both cases there are significant generic implications to other similarly designed plants that employed the same tube bending process with the same small bend radii. Without stress relief (by heat treatment) after the bending process, or in the presence of flow slot hourglassing, these U-bend tubes are susceptible to stress corrosion cracking and possible tube rupture during normal operation, as experienced in Surry Unit 2 and Doel Unit 2, and during a postulated MSLB accident.

(19) Because most PWRs now in operation began operation with or converted to all-volatile treatment (AVT) secondary water chemistry, the concern over the recurrence of a Point Beach Unit 1 type tube rupture incident has been somewhat alleviated, except for those plants that started with phosphates treatment and that have been shown to have residual sludge accumulation. For plants that are still on phosphates (that is, H. B. Robinson Unit 2 and San Onofre Unit 1), careful control of the phosphate treatment with periodic sludge lancing (removal) should substantially reduce the susceptibility to tube wall degradation caused by wastage. With adequate inservice inspection programs and preventive plugging of degraded tubes, there is reasonable assurance that this type of SGT rupture can be prevented.

(20) Currently available technical information and operating experience indicate that tubes in SGs with design similar to the Surry Unit 2 and Doel Unit 2 (see Appendix H) SGs may be susceptible to stress corrosion cracking. Trojan, North Anna Unit 1, and Farley Unit 1 have recently experienced leaks in the U-bends of Row 1 tubes. These leaks were small (less than the technical specification leak rate limit), and although stress corrosion cracking is believed to be the mode of degradation, the mechanism has not been definitively characterized. Trojan has agreed to remove a Row 1, U-bend tube sample in the spring of 1980. Unless experimental and field data can identify the conditions that have led to these tube leaks and explain why some units with longer operating times have not experienced U-bend leaks, all Row 1 tubes in similarly designed and manufactured units may have to be removed from service by plugging.

3. STAFF RECOMMENDATIONS

The three SGT rupture accidents, while having generally acceptable consequence with respect to offsite doses, had the potential for more significant consequences. To ensure that any subsequent SGT rupture events do not result in unacceptable results, the staff recommends that every Westinghouse PWR licensee implement the following:

(1) Licensees should investigate other techniques to more rapidly determine the damaged SG, and these techniques should be included in the procedures and operator training.

One such technique may be to install radiation monitors in separate steam supply lines from each SG to an automatically starting AFW turbine.*

(2) 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 SGT rupture incident. In addition, RCS subcooling should be emphasized in plant procedures and operator training.

(3) Licensees should ensure that their procedures require timely securing of all feedwater to the damaged SG as soon as it is identified and isolated. The procedures may allow intermittent feeding of the SG should its level mandate such action.

(4) All licensees should ensure that their procedures and operator training program emphasize the need to expeditiously secure steam flow from the damaged SG to the TD AFP. The TD AFP should not be started (manually) unless the damaged SG has been identified, isolated, and steam from that SG to the TD AFP has been isolated. If the TD AFP has been automatically started, then 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, then there should be no significant releases in the turbine exhaust and, therefore, no reason to secure the TD AFP.

Procedural cautions and guidance as to when to secure the TD AFP, if not needed for safe plant operation, should be noted. As a minimum, running times should be logged to later determine radioactive release amounts.

(5) PWR licensees should implement adequate procedures and training to ensure the operator's cognizance of a possible MSIV closure during the cooldown following an SIS. (The staff should continue to study this feature to ensure its design adequacy with respect to SGT rupture and steam line break events.) The operator should be given corrective actions to implement immediately.

*Westinghouse has suggested that radiation monitors for each main steam line, coupled with appropriate flow instruction, should be considered.

(6) The emergency procedure should direct the operator to attempt control of the SGT rupture 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 decrease in pressurizer level and pressure is not controllable, then a manual reactor trip should be initiated before the indicated pressurizer level goes offscale (low).

(7) If the RCPs are not tripped manually as required by NUREG-0623, the RCP in the damaged loop should not be tripped. The reduction in RCS spray flow is not significant, but judging from the events being evaluated, RCS depressurization following the event has been slow, and the operator should have as much spray flow available as possible. Also, heat transfer from the damaged SG to the RCS, while small, is enhanced by greater RCS flow. Therefore, an operating RCP in the affected loop would aid in the cooldown of the damaged SG.*

(8) For those plants provided with loop isolation valves, the use of these valves following an SGT rupture should be investigated. Isolating the affected loop would provide an almost immediate abatement of SGT leakage, but would prohibit cooldown of the damaged SG. Licensees should, therefore, examine the advantages and disadvantages in their plant of loop isolation.

(9) Following an SGT rupture event, SI actuation may occur on low pressurizer pressure. If RCS pressure continues to fall below the plant-specific predetermined value described in NUREG-0623, the RCPs should be tripped.

(10) Licensees should develop procedures to restart the RCPs after an SGT rupture event if they were tripped as a result of low-pressure SI actuation concurrent with RCS pressure falling below a predetermined, plant-specific pressure (as specified in NUREG-0623). The procedures should, as a minimum, require positive diagnosis of an SGT rupture accident, adequate RCS subcooling, adequate pressurizer level, and the fulfillment of all other RCP restart requirements.

(11) The use of the pressurizer PORV may be necessary following an SGT rupture accident. If the PORV is required to control RCS pressure upon 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.

(12) Licensees should review and upgrade radiation monitoring equipment (and its associated surveillance requirements) to assure that reliable monitoring of all release points (i.e., steam jet air ejector, ADVs, AFW turbine, and SG blowdown lines) is available during an SGT rupture accident. In addition, the operators should be properly instructed in the interpretation of valuable diagnostic information available from a properly functioning RMS. The system can contribute to an early diagnosis of the accident, as well as to a reliable identification of the faulted SG.

*Westinghouse disagrees with the staff and states that the RCP in the damaged loop should be tripped to enhance RCS subcooling. The staff is presently evaluating this assertion with respect to RCS subcooling.

(13) The limits on coolant activity given in the Standard Technical Specifications should be implemented at the remaining PWR plants without these limiting conditions for operation on a priority basis to ensure that the radiological consequences of SGT rupture accidents will not exceed a small fraction of the 10 CFR 100 guidelines.

(14) To assure correct operator response and plant controllability when bulletin requirements affect emergency procedures, the procedural changes and the operator response should be evaluated using the simulators.

(15) Licensees should investigate the means available to the plant operators to determine whether an SG or steam line ADV is either stuck open or leaking. Because the inadvertent or improper operation of these valves can result in a significant increase in the offsite doses during an SGT rupture, licensees should implement measures to positively identify and isolate an improperly operating ADV on the damaged SG. If appropriate, upgrading of the maintenance and surveillance requirements on these valves should be incorporated.

(16) Westinghouse has stated that it is possible for one or more of the following situations to occur during the SGT rupture accident (either before or after operator intervention):

(a) Automatic opening of the pressurizer PORV(s) and/or the SV(s)
(b) Water solid or drained pressurizer
(c) Saturation conditions in the RCS

Every licensee must ensure adequate procedural steps and operator training so that proper identification and correction of the condition can be performed. (See item (5) below.)

As a result of our review of the three SGT rupture accidents, the following staff actions are also recommended:

(1) A sample audit of operator training using site procedures on other than site-specific simulators should be conducted by NRC to determine whether the training received is realistic and practical. A determination should be made as to whether this training is adequate for the operator to relate the emergency procedures to his specific control boards and plant systems.

(2) Future reviews of SGT rupture accident analyses for construction phase (CP) and operating license (OL) stage plants should require a more detailed description of the system performance during the event. Plots of the various parameters should be provided so that a better understanding and documentation of the event can be achieved.

(3) The staff, together with two-loop Westinghouse PWR licensees, should investigate the MSIV closure logic to ensure that its operation does not violate any assumptions in the respective FSAR analyses. The staff should also look at the FSAR analyses where MSIV operation is assumed, and assure that the logic is consistent with the required operation.

(4) The staff, together with Westinghouse, should continue to study the phenomena associated with stress corrosion cracking in the U-bend region of the Row 1 tubes and implement measures necessary to eliminate Row 1 tube cracking.

(5) The staff, together with Westinghouse, should determine the potential for the undesirable system conditions listed previously in item (16) during an SGT rupture accident and the subsequent RCS cooldown/depressurization for each PWR. Since the system conditions will depend on SGT rupture size, SIS design characteristics, and specific operator actions, the staff, together with Westinghouse, must ensure that the analyses adequately cover the different plant designs and situations.

(6) The NRC I&E inspectors should ensure implementation of the recommendations for Westinghouse PWR licensees stated earlier in this section and should review and ensure licensees' conformance with these items.

4. PWR BEHAVIOR DURING AN SGT RUPTURE EVENT

The behavior of a PWR during an SGT rupture event depends, to some extent, on the design of various systems associated with the event. The details of the relevant systems are shown in Appendix G. However, the overall behavior of PWRs during SGT rupture accidents should be somewhat similar.

The condenser air ejector radiation alarm provides an early indication of an SGT rupture. The air ejectors remove noncondensable gases from the condenser. Therefore, the radioactive gases transported by the RCS liquid through the broken SGT into the secondary are first detected in the condenser air ejector discharge. The discharge path is monitored with radiation detectors, and this alarm provides a unique indication of a primary-to-secondary system leak.

The SG blowdown system continually removes accumulated sludge and other heavy precipitates from the bottom of the SG. The blowdown system also has a radiation monitor, but the flow rate and mixing times are such that a delay in detecting the radioactive contaminants may occur.

If the SGT rupture occurs in a sudden manner, the loss of the RCS inventory through the break causes a sudden drop in RCS and pressurizer pressure and pressurizer level as shown on Figure 1. The charging system in Westinghouse PWRs generally operates in an automatic mode such that deviations in pressurizer level from a preprogrammed pressurizer level, which depends on T_{AVE}, causes either an increase or decrease in charging flow. For those plants having centrifugal charging pumps, the charging flow is controlled by an air operated throttle valve in the charging stream. For those plants having variable speed, positive displacement charging pumps, the charging flow is adjusted by varying the pump speed.

The loss of pressure and pressurizer level cannot be controlled by the operation of a single charging pump at full flow, unless the break is small. The charging pumps at Prairie Island Unit 1 and Point Beach Unit 1 are rated at 60.5 gal/min; at Surry, at about 175 gal/min. However, FSAR analyses from PWR licensees and the actual SGT rupture events being evaluated in this report have shown that most cases of SGT failures (even smaller in size than the design "double ended SGT break") result in a pressure and level loss that cannot be controlled by a single charging pump.

Without any operator action, RCS pressure would drop to the low-pressure scram setpoint, about 1815 psig. Staff analyses for FSAR-predicted leak rates have shown that for pressure to drop from normal (2235 psig) to the scram setpoint without any operator action can take about 2-1/2 min.

Once the reactor has automatically tripped on low system pressure, the steam dump and bypass system takes over to automatically reduce RCS temperature T_{AVE} from the full load value, about 560°F, to the no load value of about 545°F. The control system senses the turbine first-stage shell pressure (FSSP) and computes a signal, called T_{REF}, based on it. Because FSSP is almost linearly related to power, T_{REF} varies linearly with power. The steam dump and bypass system is controlled by the deviation between T_{AVE} and T_{REF}. If the deviation is excessive (that is, if T_{AVE} exceeds T_{REF} by more than an allowable value), the turbine bypass valves open to admit steam from the main steam headers to the condenser. If the condenser vacuum is below that permissible, the steam

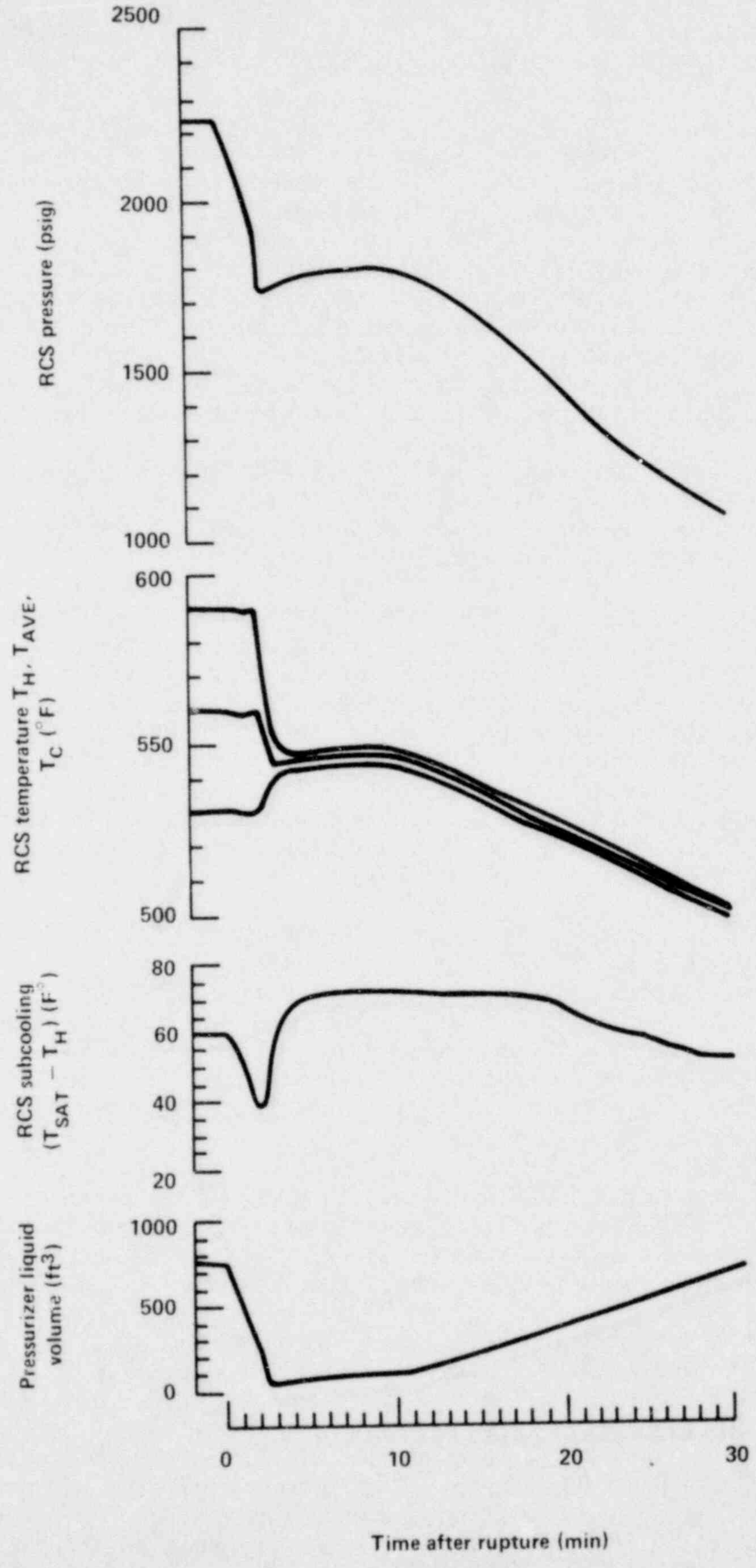

Figure 1. RCS parameters during SGT double-ended rupture (with operator action)

dump valves (to the condenser) are prevented from opening. A LOOP would also prevent the turbine bypass valves from opening because they are interlocked with the main circulating water pumps and these would be unavailable following a LOOP.

If the turbine bypass valves are prohibited from opening, then the only means left to control the SG pressure are the ADVs and the SG SVs. The ADVs and SVs are usually located on each steam header upstream from the MSIV. The ADVs are air operated and automatically open when header pressure exceeds a predetermined value, or when the operator takes manual control (control room). The SVs are spring loaded and open on header pressure alone.

The automatic RCS cooldown from full load to no load T_{AVE} results in a further reduction in RCS pressure and level. Now the combined effect of the RCS automatic cooldown and the loss of mass (and energy) through the break causes the pressurizer level to drop below the indicating range (representative of a double-ended SGT rupture (or equivalent)), and the pressure to drop to the SIS initiation value, about 1700 psig.

The automatic initiation of SIS causes the automatic start of the HPSIPs and the LPSIPs, the automatic trip and isolation of the main feedwater pumps, and the start of the AFPs.

Without any operator action, the RCS pressure stabilizes at a value so that the mass input rate from the HPSIPs is matched by the SGT break flow. This pressure is highly plant dependent and will depend on several factors. If the SGT break is large (e.g., a complete tube break) and the HPSIP is a relatively low head pump, then final pressure would be relatively low. However, if the break size is small and the HPSIPs have a high shutoff head, then final pressure would be high. (Figure 1 represents a large break with a relatively high head HPSIP.)

The break flow into the secondary of the damaged SG does not result in any immediate level change resulting from the operation of the three-element SG level control system. However, once the plant scrams, the level in the damaged SG rises because appreciable steam flow from the SGs has stopped. The leakage into the damaged SG continues until the operator intercedes to perform the following acts:

(1) Determines which SG is affected and shuts off feed flow and the MSIV

(2) Takes control of the SIS and stops unnecessary HPSIPs*

(3) Reduces RCS pressure by manipulating the cooldown rate (using steam dump valve or ADV) and HPSIP operation.

Analyses and actual occurrences have shown that the pressurizer level remains below the indicating range until system pressure is reduced to a point at which HPSIP flow exceeds the SGT break flow.

*This action is stated in the FSAR, but the new Westinghouse procedure for SGT ruptures (E-3) has the HPSIP remain on for some period so to ensure RCS subcooling.

The RCS is cooled using appropriate normal or emergency techniques (except the faulted SG is isolated until the residual heat removal (RHR) system can be used). The RCS should remain subcooled during the cooldown as long as the plant operators carefully observe RCS temperature and pressurizer pressure. As shown in Figure 1, the minimum RCS (hot leg) subcooling margin should occur just prior to reactor trip (before automatic RCS cooldown).

Because the actual plant performance during the SGT rupture event depends on the systems and design of each plant, Appendix G compares the various system design features for the three plants under review.

5. DESCRIPTIONS OF ACTUAL SGT RUPTURE EVENTS

An SGT rupture can be defined as any SGT leak rate that exceeds the normal charging flow capability. The staff is aware of only five PWR SGT rupture events: three at domestic Westinghouse PWRs and two at foreign reactors. Each of the three domestic SGT rupture events is briefly described in this section, chronologically, along with a short description of the actual tube break (as it was later discovered in the licensee's SG inspection) and the radiological consequences. The licensee's procedural or equipment corrective measures, including the means by which the licensee repaired the broken tube(s), are briefly described.

5.1 Point Beach Unit 1

On February 26, 1975, an SGT leak developed in SG "B" while the plant was operating at full power. The licensee estimated the leak rate at about 125 gal/min. The air ejector high-radiation alarm was the first indication of any problem. The operators then heard alarms indicating that the operating charging pump was at maximum flow and pressurizer level was decreasing. Two, then three charging pumps were placed in service in an attempt to control the pressurizer level, and the unit load was decreased to about 25%, at which time the plant was tripped manually. The SIS did not automatically or manually start, but the safety injection pump (SIP) was intermittently used during the subsequent cooldown to control RCS inventory. The RCPs were operating during most of the cooldown, and only undamaged SG "A" was used to cool the plant.

The plant was placed in a cold shutdown condition and the leaking tube was identified. The tube was located in the outer row on the RCS inlet (hot leg) side of the SG. The licensee estimated that approximately 2265 Ci of Xe-133 equivalent was released to the environment. Later inspections of the SG suggested a complex, multiple defect close to the tube sheet. Boroscope examinations of the leaking tube showed bulging of two defects, axially aligned, about 1-1/2 by 3/4 in.

The licensee conducted an investigation to determine the adequacy of the monitoring system on the air ejector and blowdown systems, and the adequacy of plant emergency procedures. Changes in both areas were made. These are further described in Sections 7.1.1.4 and 7.1.2, respectively. Wisconsin Electric Power Co. (WEPCO) made changes to the internals of the hot-leg side of the secondary of the SGs where sludge is known to precipitate and plugged the affected SG tubes (see Appendix C).

5.2 Surry Unit 2

On September 15, 1976, an SGT leak occurred in SG "A" while the plant was operating at full power. The licensee estimated the leak rate at about 80 gal/min. Flux mapping for nuclear instrument calibrations was in progress when the air ejector high-radiation alarm was heard. In an effort to control the rapidly decreasing pressurizer pressure and level, a second charging pump was started. Control rods were moved to return T_{AVE} back to program because the operator ordered a stop to flux mapping when he began to suspect a problem. The leak started slowly and was barely apparent for several minutes. The plant operators restored program rod height to restore T_{AVE} to eliminate any masking effects due to slight temperature variations. A reduction in turbine load to 10% was manually initiated. The turbine load had been reduced approximately 30% when a manual turbine trip (and subsequent reactor trip) was initiated. This occurred before RCS pressure reached the low-pressure trip. The SIS was manually initiated.

The damaged SG was positively identified, and the secondary side was isolated. The RCS was cooled using the intact SGs and the normal steam dump system and was placed in a cold shutdown mode. Because no ADV or SV actuation occurred, no direct releases from the affected SG resulted. Also, air ejector discharge was automatically diverted to containment. This eliminated the potential release path to the environment from the air ejector.

Later SG inspection showed an axial crack about 4-1/4 in. in length in the U-bend apex of a Row 1 SG tube.

The licensee removed the U-bend portions of the failed tube and eight additional adjacent tubes and plugged the inlets and outlets of those tubes and those of several other tubes (see Appendix C).

5.3 Prairie Island Unit 1

On October 2, 1979, an SGT leak developed in SG "A" while the plant was operating at full power. The licensee estimated the leak rate at about 390 gal/min. The air ejector high-radiation alarm was the first indication of any problem. Two more charging pumps were manually started in an effort to control the rapidly dropping system pressure and pressurizer level; however, an automatic reactor trip on low pressure occurred. The ADV on SG "A" lifted for 1 to 2 s. Automatic SI on low pressurizer pressure resulted (no concurrence with low pressurizer level was necessary), and the operator manually tripped both RCPs. Because normal pressurizer spray was therefore not available, the increase in RCS pressure was reduced by the manual operation of one pressurizer PORV. Steam leaving the pressurizer via the PORV caused the quench tank rupture disk to rupture, as designed. The RCS pressure dropped, and the operator shut the PORV and secured the SIPs. The RCS was cooled using the natural circulation flow and steaming from the undamaged SG. Later, the RCPs were restarted and the cooldown continued until the system was placed in a cold shutdown condition. The licensee estimated that about 30 Ci of Xe-133 equivalent of noble gases and about 1 μCi of I-131 equivalent of iodine isotopes were released.

Subsequent inspection of the damaged SG revealed a foreign object near the damaged tube. This object was determined to be wearing against the tubes, causing a significant reduction in wall thickness.

The licensee reviewed the event and associated procedures and several necessary procedural and equipment changes were identified. The failed tube and four adjacent tubes that showed signs of wear were plugged.

6. CAUSE OF RUPTURED SGTs

This section describes the reasons the SGTs ruptured in the three events. A general discussion of SGT rupture mechanisms is contained in Appendix C.

6.1 Point Beach Unit 1

Inspection of SG "B" following the tube leak included eddy current testing (ECT) and borescopic examination. The nature of the eddy current signal from the leaking tube suggested that a complex, multiple defect was present. Signals typical of stress corrosion cracking were observed in the area just above the tube sheet. Although the leaking tube was not removed for examination, a borescope viewing of the leaking tube showed bulging of two longitudinal defects, the total length of which did not exceed 1-1/2 in., and neither of which exceeded 3/4 in. Although the leaking tube had not been previously inspected, the location of the leak is consistent with the hypothesis that wastage had previously occurred on the tube and that a combination of wastage and caustic stress corrosion cracking led to the tube failure.

The licensee subsequently inspected nominally all tubes in both SGs by ECT. The results of the tube inspection are presented in Table 1.

Table 1

Results of SGT inspection

Reduction in wall thickness (percent)	No. of Indications SG "A"	SG "B"
Less than 30	262	36
30 to 60	11	19
Greater than 60	48	79

6.2 Surry Unit 2

Investigation established that the leak resulted from an axial crack approximately 4-1/2 in. in length at the top of the U-bend of a Row 1 tube.

Removal of the damaged tube and subsequent laboratory analysis revealed that the failure was caused by the U-bend stress corrosion cracking mechanism described in Appendix C. Eight additional tubes (next to the failed tube) were removed from Row 1; five of the eight showed significant ovalization of the tube and the presence of cracks on the inner surface.

The failed tube and the other five containing crack indications were located near the middle of a flow slot. The observed hourglassing on the top support plate flow slots "pulled the legs" of the U-bend closer together causing additional hoop stress at the apex of the U-bend and is believed to have enhanced susceptibility to stress corrosion cracking. The three remaining tubes, located at a corner of the flow slot and therefore not subject to support displacement at the upper support plate, showed no evidence of cracking at the time of the tube removals.

6.3 Prairie Island Unit 1

Visual and fiber optic inspections performed subsequent to the tube rupture incident revealed that the SGT at Row 4, Column 1, 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 rupture break edges were observed to be worn to a "knife edge," indicating that significant reduction of tube wall thickness had occurred prior to the failure by bursting and further necking during burst. The SGTs in adjacent positions (Row 3, Column 1, and Row 2, Column 1) also showed signs of wear. ECT revealed that the Row 3, Column 1, tube (adjacent to the failed tube) had an indication of a 65% reduction in tube wall thickness. The Row 2, Column 1, tube had an indication of about 20% reduction in wall thickness. 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. gauge 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) and 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.

A second spring, identical to the first but shorter in length, was found on the cold-leg side. It was located just opposite the first spring with one end wedged underneath the flow blocking device and the other end extending out onto the tube sheet. In addition, part of a hose clamp was found next to this spring. A close visual examination of the spring on the cold-leg side, the tubes, and the tube sheet surface revealed no signs of spring movement, tube damage, or wear.

The springs and clamp are believed to be part of a hose assembly from sludge lancing equipment and were apparently left in the SG during an outage prior to the installation of the flow blocking device in March 1976. The function of the springs was to provide radial rigidity to the rubber suction hose to prevent collapse. The rubber hoses are believed to have disintegrated during service because of the high operating temperature.

A complete visual inspection of the outer peripheral area of the tube bundle and the open flow lanes for both SGs revealed no other signs of foreign objects. In addition, eddy current inspection was performed on approximately 12% of the SGTs, including all Row 1 tubes, all tubes adjacent to the damaged tubes, tubes on the periphery of the tube bundle, and a random sample of the tubes in the center of the tube bundle. No signs of degradation were found.

7. EVALUATION

Each plant analyzed the consequences of a single SGT rupture in its FSAR. The analysis was conducted in accordance with the guidelines in effect at the time the plant was licensed. In general it had to be shown that dose rates to an individual standing on the site boundary of a PWR were less than the 10 CFR 100 rules. At certain times during the operation of the plant since the original design, plant features or analyses techniques may have changed, necessitating a new or revised SGT rupture analyses (also showing conformance with the applicable rules). For each of the three plants that suffered an SGT rupture, evaluation began with a comparison of either the FSAR SGT rupture event, or a later analysis that constitutes the analysis of record, and the actual SGT rupture event. Appendix A shows a representative FSAR SGT rupture analysis; Appendix B gives all three SGT rupture event sequences.

The staff performed analyses of the actual system performance during each SGT rupture event to ensure the system responded in an expected manner. To guarantee that the analysis of record for that particular plant suitably represents actual system behavior, the staff looked for unusual behavior. Because safety analyses are conducted using conservative or bounding type assumptions, the staff analyzed the actual system behavior to ensure its operation was bounded by the reference analyses.

Each reference analysis assumes some degree of operator response within a certain time interval following the event. For each plant, the staff examines the following aspects of the operator's response:

(1) the adequacy of the SGT rupture emergency procedure
(2) the training the operators receive on the equipment and procedures for an SGT rupture event
(3) the actual performance of the operators during the event

The reference analyses, presented for each plant, assume certain release paths and release time intervals. The staff examined the event with respect to any additional release paths not considered in the reference analyses and ensured that the amount of activity released was both negligible and could be ignored in the reference analyses.

The systems or operator responses, radiological considerations, and SGT failure mechanisms for each of the three plants are then compared to show important similarities and differences.

7.1 Point Beach Unit 1

7.1.1 Systems Performance

The Final Facility Description and Safety Analysis Report (FFDSAR) analyses of an SGT rupture event with offsite power (OSP) was performed assuming conservative initial conditions, plant behavior, and operator actions. During the SGT rupture event on February 26, 1975, the actual plant parameters and systems performance differed from those previously assumed. The staff analyzed the performance of the various plant systems during the actual event to ensure their performance was within the FFDSAR predicted performance, and to see if any previously unknown or unexpected plant behavior was experienced.

7.1.1.1 Reactor Coolant System

7.1.1.1.1 Pressure and Pressurizer Level

The actual SGT leak rate was significantly less than that predicted in the FFDSAR, which assumes a completely severed SGT. The licensee estimated the leak rate* at 125 gal/min, and the FFDSAR predicts an initial leak rate of 80 lbm/s (about 800 gal/min), rapidly decreasing to 40 lbm/s (about 400 gal/min). Therefore, the actual RCS pressure and pressurizer level response should have been less severe than predicted in the FFDSAR.

The licensee's abnormal occurrence report states that at 2313 the first charging pump was at full speed. At 2314, the speed of the second pump was being manually increased in an effort to control the slow drop in pressurizer level. From 2314 until 2331, the L_p had dropped about 6%, and normal letdown and RCP seal flow were in operation. There had been no changes in RCS temperature; therefore, the changes in system inventory were assumed to be caused by the leaking SGT only. Based on this information, the staff calculated the SGT leak rate to have been between 70 and 100 gal/min, depending on the actual manipulations of the second charging pump. (These calculations also assume an instantaneous SGT leak rate up to the final leak rate, which was probably not the case.)

Because the licensee estimated a 125-gal/min leak rate apparently based on secondary system changes, the two estimates are not considered to disagree significantly.

The licensee did not state in the report explicitly how quickly RCS pressure was dropping during the event, and the pressure values at specified times are not available. Therefore, the staff performed scoping calculations to determine how rapidly the system pressure should have been dropping with the reported leak rates to determine what the other system responses should have been. Table 2 shows the expected time for RCS pressure to drop from normal operating pressure (NOP), 2235 psig, to the low P_p scram at 1865 psig, and Table 3 shows the expected time for pressure to drop from the scram setpoint, 1865 psig, to the SIS actuation pressure, 1715 psig. These calculations were performed for two leak rates and three chemical and volume control system (CVCS) configurations.

In Case 1 it is assumed that the operator does not take any action until the reactor scrams and SIS actuation occurs.

In Case 2 it is assumed that the operator recognizes instantaneously the accident and takes immediate actions aimed at preventing the depletion of the primary coolant inventory.

In Case 3 the actual sequence of operator actions is assumed. The scram and SIS actuation times calculated in this case are slightly different from the

*The licensee's estimated leak rate was probably determined based on "B" steam level changes in SG "B."

Table 2

Time for RCS pressure to drop from normal (2235 psig) to the low P_p scram (1865 psig)

Case	Time (min) FSAR-calculated leak rate of 800 gal/min	Licensee - estimated leak rate of 125 gal/min
1	3.3	22.6
2	4.4	No scram
3*	3.6	No scram

*This case assumes a linear reduction in about 45s from full load T_{AVE} to the T_{AVE} corresponding to 25% load. The automatic reduction in pressurizer level is not included in our calculations.

Table 3

Time for RCS pressure to drop from the low P_p scram (1865 psig) to the low P_p SIS setpoint (1715 psig)

Case	Time (s) FSAR-calculated leak rate of 800 gal/min	Licensee-estimated leak rate of 125 gal/min
1	23	30.0
2	30.7	NA
3*	24.8	NA

*This case assumes a linear reduction in T_{AVE} from the 25% power value to the no-load value in about 15 s.

actual times because of some simplifying assumptions made by the staff. These same assumptions were made for other plant scoping calculations; the results are therefore comparable.

Table 2 shows that the rate of RCS pressure drop with three charging pumps, and with a slow reduction in T_{AVE} (Case 3), was quite low and allowed the licensee time to perform an orderly unit shutdown.

If the reactor had automatically tripped on low P_p, which could have happened as shown in Table 2, and if the charging pumps had not been rapidly placed into operation, the RCS pressure and pressurizer level would have dropped rapidly because of the automatic rapid RCS cooldown. The RCS pressure could have dropped to the SIS initiation setting, 1715 psig, and the system pressure and pressurizer level would have experienced a more severe transient. Most Westinghouse plants were designed so that automatic SI occurred if pressurizer pressure and pressurizer level together went below a predetermined value. At the time of the Point Beach Unit 1 event, the SIS logic required these concurrent signals. Recently, as a result of the TMI-2 event and the apparent pressurizer level inaccuracy, the pressurizer level signal was deleted as an input to the SIS logic.

The rate of change of pressurizer level was also not given by the licensee in his report, and traces of this important plant parameter are likewise not available. The staff performed similar scoping calculations to determine the rate of change of pressurizer level for the same equipment and system configurations shown in Tables 2 and 3.

These scoping calculations show that the use of three charging pumps at full speed (full flow), the relatively slow SGT leak rate, the isolation of letdown, and the slow reduction in reactor power combined to make the L_p controllable during the event. The calculations show, however, that if all three charging pumps had been immediately available and used at full speed and letdown had been immediately isolated, the scram would have been delayed but could not be avoided. If reactor power is high at the time of scram, there is a greater chance that SG ADVs or SVs will open. Therefore, longer times to scram allow for greater reduction in power and, hence, less chance of direct releases to the atmosphere through the faulted SG ADVs or SVs.

The licensee was able to perform a slow, controlled reduction in load before any scram setpoints were reached. A slow and controlled reduction in load is desirable from the standpoint of avoiding SIS initiation and the accompanying thermal and hydraulic shock to the system and in minimizing offsite releases. In addition, a trip from 100% power may open secondary SVs or ADVs and cause a direct release to the environment. However, maintaining RCS pressure at close to NOP for this extra time results in increased leakage to the affected SG.

The FFDSAR analysis for an SGT rupture with offsite power available states that for the complete severance of a single SGT, the RCS and SG pressures should be equilibrated and below the lowest set secondary SV in about 30 min. In the actual event, since the leak rate was about one-seventh of the FFDSAR leak rate, it was not necessary to reduce the RCS pressure as quickly. Consequently, the

RCS pressure was reduced to 1000 psig about 1 h, 45 min after the tube rupture, or about 75 min longer than assumed in the FFDSAR. The extra time did not result in extra releases directly to the atmosphere, however, because the affected SG MSIV had been closed immediately after the reactor was tripped, and the pressure in the affected SG was less than the setpoint of the ADV or SG. Nevertheless, the relatively slow RCS depressurization resulted in increased leakage to the SG. Scoping calculations show that the extra 75 min to equilibrate the RCS and SG pressure resulted in as much as an extra 4600 gal of leakage.

The relatively slow RCS depressurization did allow the RCS pressure to be carefully controlled and enhanced the operator's ability to ensure adequate subcooling during the reduction in RCS temperature and pressure. As stated in the detailed sequence, the L_p was controlled during the cooldown evolution using intermittent operation of the HPSIPs. Therefore, apparently there was no difficulty in maintaining sufficient RCS inventory.*

The staff calculated the maximum obtainable RCS depressurization rate assuming the use of the normal spray valve with both RCPs running, normal spray with only one RCP running, and the pressurizer PORV. If a simultaneous RCS cooldown had been assumed, the depressurization rate would be greater because of the colder spray water and the RCS contraction. The RCS is assumed to remain isothermal for these calculations. Pressurizer level is assumed constant since the HPSIPs were intermittently used to maintain pressurizer level. The staff scoping calculations showed that the depressurization rates are essentially linear:

Component	dp/dt (psi/min)
1 RCP, normal spray	55
2 RCPs, normal spray	120
1 PORV	450

It was well within the capability of the normal spray (with one or both RCPs operating) or the PORV to reduce system pressure to around the faulted SG pressure within about 30 min and still maintain adequate subcooling.

7.1.1.1.2 Boron Concentration

The FFDSAR states that the HPSIPs provide automatic RCS boration as the system cools down and as boric acid is lost through the rupture. Additional boration is also necessary because the secondary water in the broken SG will act to dilute the RCS boron concentration when the RCS pressure is lowered below the affected SG pressure.

As shown in Appendix G, when the SIS is initiated, the Point Beach Unit 1 HPSIPs take a suction on the boric acid tanks (BATs). The FFDSAR analysis of the SGT break states that the SIPs provide automatic RCS boration, but during the actual SGT break event, the SIPs were used only intermittently, and their suction was probably aligned to the BAT (normal lineup). All three charging pumps were used almost continuously, and, apparently, the volume control tank (VCT) was used as the water source.

*The staff calculated that with three charging pumps at full flow, with the SGT break leak rate decreasing linearly with RCS pressure reduction, and with a linear RCS cooldown at about 100°F/h, the pressurizer level will be dropping at about 36.4 gal/min.

From the time the event occurred until about 12 min after the reactor was manually tripped (after having been ramped from 100% to 25% power), the charging pumps (various numbers) were drawing from the VCT. Therefore, during this interval, about 1 h, the RCS boron concentration should have remained essentially constant. However, after the first hour the charging pump suction was aligned directly to the refueling water storage tank (RWST), and the SIPs, which were intermittently used during the cooldown, were also presumably aligned to the RWST.

The staff notes that the RCS boron concentration during RWST water addition should have been increasing. However, the staff could not determine or estimate the RCS final boron concentration (before pressure equalization with the damaged SG because of insufficient information. Nonetheless, based on the VCT and RWST boron concentrations, the RCS boron concentration, up to the time the RCS and broken SG pressures are equalized, should have remained acceptable (i.e., greater than the initial RCS boron concentration).

The staff does not know the actual RCS boron concentration prior to pressure equalization, so the dilution factor could not be calculated; but based on the calculations in Appendix D and the highly conservative nature of these dilution calculations, it is concluded that no criticality problem existed during the Point Beach SGT rupture event.

7.1.1.1.3 Flow

Removal of core decay heat depends on either forced or natural circulation through the RCS. Without any flow, RCS fuel temperatures would increase and could lead to unacceptable consequences. The FFDSAR analysis for the SGT rupture case where OSP is retained assumes the continued operation of the RCPs. The analysis documentation does not state whether the RCP in the loop containing the affected SG is tripped. In the actual occurrence, both RCPs were kept operating until about an hour after the event when the RCP in the loop containing the damaged SG, RCP "B," was manually tripped. The pump remained tripped for about 30 min. Apparently, the pressure and temperature in SG "B" were not satisfactory since RCP "B" was restarted to aid in SG "B" cooldown. It is unclear how starting the RCP could have been a significant factor in cooling SG "B."*

Throughout the remainder of the RCS cooldown, RCP "B" was left operating. Later, when SG "B" pressure and/or temperature was too high, MSIV "B" was bypassed by means (of a 3-in. line around the MSIV with a manually operated valve) to bleed steam to the condenser.

Although tripping RCP "B" was apparently not assumed in the FFDSAR analyses, this presented no adverse effects since there was always sufficient core flow for the removal of decay heat using SG "A"; however, there was a loss of some normal spray flow since the two scoops are positioned downstream from the RCPs.

*With the pump tripped, the primary flow through the broken SGTs is in the reverse direction and is T_C of the core. With the pump operating, the flow is in the correct direction and is T_H. However, the flow is greater with both pumps running than with only one. These effects are in opposite directions for energy transfer from the broken SG into the RCS; therefore, it is difficult to determine whether cooling of the broken SG could have been aided by restarting the RCP.

In fact, tripping RCP "B" removed the thermal input of the pump and thereby allowed a somewhat faster cooldown. However, the staff believes that the RCS cooldown rate without this thermal input was only marginally improved, if at all, and that, generally, the higher the core flow, the better the RCS cooldown.

7.1.1.2 Safety Injection System

According to the FFDSAR, for a fully severed SGT at the bottom of the SG in the vicinity of the tube sheet, SIS is necessary to both recover and control RCS pressure and pressurizer level. However, the actual SGT break size was less than that assumed in the FFDSAR, and the SIS was never automatically actuated. The SIPs were intermittently used at various times during the RCS cooldown to maintain adequate pressurizer level. (The variation of pressurizer level during the event is discussed in Section 7.1.1.1.)

7.1.1.3 Secondary Systems

The control of the SG pressure and level during the SGT rupture directly affects the consequences of the event, and each is evaluated in this section.

7.1.1.3.1 SG Pressure Control

The FFDSAR analysis states that the operator must isolate the affected SG by closing its MSIV and commence an RCS cooldown (using the intact SG ADV or normal steam dump) within about 10 min following the event. During the actual event, SG "B" MSIV was not closed until the plant had been manually tripped (after ramping power from 100% to 25%), about 48 min after the SGT rupture occurred and 20 min after the operators realized they had an SGT rupture. The extra 38 min of flow from the damaged SG should not have resulted in any appreciable releases because the SGT leak rate and the RCS activity were less than assumed in the FFDSAR analysis. Maintaining the MSIV open until the plant was shut down was prudent because closure of the MSIV on a steaming SG could have resulted in ADV or SV operation.

Although not specifically mentioned in the licensee's report, apparently the damaged SG "B" pressure and temperature started increasing during the RCS cooldown and depressurization, perhaps because of stored energy in the SG metal and the continued leakage. The licensee tripped the affected RCP--apparently in an effort to reduce flow through the break.

The pressure of intact SG "A" was controlled using the manual steam dump mode to the condenser. There were apparently no difficulties in obtaining the necessary steam flows for the desired RCS cooldown rate, because the RCS was cooled down so slowly.

7.1.1.3.2 SG Level Control

The damaged SG level must be kept as low as possible to avoid overfilling and flooding. This is accomplished by reducing RCS pressure as quickly as possible, which, as stated previously, was not done, and by securing all feedwater to the damaged SG. During the actual event, SG "B" was receiving feedwater for about 10 min after the MSIV was closed. Because no traces of feed flow or SG level are available, it could not be determined how much feedwater was being delivered to the damaged SG or what the level was. The FFDSAR analysis states that the damaged SG feedwater flow should be secured within 10 min; however, the actual leak rate was about 13% of the FFDSAR leak rate. Nonetheless, it cannot be stated that the extra 10 min of feed flow to the damaged SG did not contribute to the later problems in high SG "B" level. It is obvious that the relatively slow RCS depressurization contributed to the SG "B" level.

The level in the intact SG was controlled using the normal feedwater system* during the early part of the event and the AFW system during the cooldown.**

No anomalous behavior regarding SG level, other than the extra 10 min of feed flow, was noted. However, the steam supply to the TD AFP can be from either SG, upstream of the MSIVs. Apparently, steam from the damaged SG was directed to the TD AFP, since the licensee had to include this flow as a release flow path.

7.1.1.4 Miscellaneous Systems

The SG blowdown system and the condenser air ejectors were important in the overall course of events. Each system is briefly described in Appendix F, along with its normal operation and how it functions during the SGT rupture event. Their operation is evaluated in the following paragraphs.

7.1.1.4.1 SG Blowdown

As indicated in Appendix B, the event sequence, the blowdown from SG "B" was remote manually secured after the sample cooler high radiation field had been detected. R19, the SG blowdown sample monitor, sounded the alarm and performed its automatic function of isolating the SG sample and blowdown lines, only after manual manipulation of the flow control valves allowed enough flow through the system to initiate the alarm. While this instrument would have performed its intended function of isolating the blowdown and sampling lines during the incident, the delay time involved in producing the required response has been shown to be excessive, i.e., approximately 20 min.

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*After a reactor trip, the main feedwater control valve automatically opens fully to increase feed flow to both SGs to aid in reducing the RCS temperature to the no-load value. The valves remain fully open until either an abnormally high value of L_{SG} occurs, an SI signal occurs, or $T_{AVE} - T_{REF}$ is reduced to the desired value of ΔT.

**The AFW system is composed of two steam-driven pumps, one for each unit, and two motor-driven (MD) pumps, which are shared by both units (i.e., both MD pumps feed a common header, which supplies AFW to all four SGs. The steam-driven pump is automatically started when there is low-low L_{SG} in both SGs and loss of 4-kV power supply to the normal feedwater pumps. Both motor-droven pumps are started when there is low-low water level in any SG, when there is a trip of both main feed pumps in either unit, or when the Safeguards Sequence Signal actuates.

Modification requests for both Units 1 and 2 were issued to improve the reliability of the R19 monitors and, additionally, to provide redundancy and an improved transit time for the function of isolating the SG blowdown lines.

To improve the reliability of flow and the transient time of R19, these monitors were provided with a separate tap from the SG blowdown sample line upstream of an existing pressure reducing valve. Following flow rate measurement and sampling, the discharge will be directed to the service water outlet piping as opposed to the present path to the SG blowdown tank.

This new and more direct path reduces the complexity of the original system, which required dividing the flow between radiation monitoring, pH sampling, and conductivity sampling, using manually operated valves. This could lead to possible inadequate flow for any given sampling point.

To provide redundancy and improve speed of response of the SG blowdown isolation function, a strap-on type detector was attached to the liquid discharge pipe of each SG blowdown tank. Upon receipt of a radiation signal, the monitor will initiate closure of both SG blowdown valves and the SG blowdown tank liquid discharge valve. The strap-on type monitor will not initiate closure of the SG blowdown sampling valves. A closing signal will later be received by these valves following time lapse of the sample liquid R19.

7.1.1.4.2 Air Ejector

One of the first indications of a problem with Unit 1 at the time of the incident was the R15 alarm. When the specific channels were visually observed, however, no significant abnormalities were seen, although R15 was noted to be dropping somewhat. Because of the saturation of R15, the resulting downscale reading gave operational personnel a false picture of the actual events at that time. The Incident Report described their subsequent and correct reactions to this misleading information.

Detailed examination of the circuitry of the R15 monitor determined that should the monitor encounter a field greater than the fullscale reading of the instrument, the preamp would cease to generate pulses as the Geiger Müller (GM) tube saturated. The meter would then give a false low readout indication. To correct this, modification requests for both Units 1 and 2 were issued to modify the circuitry and detection systems to eliminate this problem.*

7.1.1.4.3 Auxiliary Building Exhaust Stack Monitor R14

During the incident, the R14 monitor gave incorrect information as it reacted to "shine" from sources of radiation outside of the stack, i.e., the main steam line and the air ejector piping. This caused the monitor to indicate releases that were, in fact, not occurring.

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*A detector and oscillator were installed in parallel with the preamp. Should the GM tube again saturate, the detector will sense this and the oscillator would send out a full-scale pulse rate to the control room electronics such that the meter will remain at full scale during the saturation period. Recovery of the GM tube from saturation would cancel the oscillator pulsing.

An in-plant modification request was prepared to change the existing in-stack monitoring system to an off-line sampling system in which gases would be drawn off the stack by a vacuum pump via an isokinetic sampling probe and then passed through particulate and charcoal sample for release accountability. The monitor was placed at a shielded remote location.

7.1.2 Operator Response

The Point Beach Unit 1 SGT rupture event was a relatively mild occurrence and allowed the operators sufficient time to conduct a well ordered plant shutdown. Nevertheless, some deficiencies were noted and each is described in the three main categories of operator response: operator training, emergency procedures in effect then and now, and actual operator actions.

7.1.2.1 Operator Training

Emergency procedure training is accomplished by formal class presentation as part of the site operator requalification program. Specific areas addressed in class are actual experiences and a licensee event report (LER) review of occurrences at other plants that may be applicable. On-the-job discussion sessions are conducted as part of the shift training program.

Simulator training at Point Beach is similar to training at the Prairie Island plant and is conducted using site-specific emergency procedures modified to accommodate differences in control room boards and plant systems. There are no two-loop simulators; therefore, operators are trained on a simulator not truly representative of the plant in which they work. The operators must retrain on the procedures and on the simulator approximately every year.

7.1.2.2 SGT Rupture Emergency Procedure

The procedural requirements for the SGT rupture event were reviewed by the staff with respect to analysis of record requirements (and assumptions) and actual system performance during the event. The procedure in effect at the time of the occurrence was reviewed. Staff concluded that it was sufficiently detailed, contained step-by-step guidance, and was adequate to bring the plant to a safe condition. The SGT rupture event procedure symptoms segment was adequate and led the operator to successfully diagnose the situation.

As a result of the event, Wisconsin Electric Power Co. made several procedural changes. Several other changes have since been implemented. However, these changes are relatively mild and do not significantly change the procedures.

The staff concludes that based on the actual event, the procedures were deficient and lacked the following:

(1) The procedures did not make allowance for relatively small SGT leaks that would not necessitate immediate plant trip, SIS actuation, and other actions associated with a large SGT rupture.

(2) The procedures did not emphasize securing early feed flow to the damaged SG because leakage will continue into the secondary all during RCS cooldown, until pressure is equalized.

(3) The procedures did not ensure that steam from the damaged SG would not be used for TD AFP operation.

7.1.2.3 Operator Actions

The operator response to the Point Beach Unit 1 event is described in Appendix B. Operator actions closely parallel the operator response described in the Surry Unit 2 event. The major difference was that the operator could control RCS inventory losses (pressurizer level) with maximum charging and, later, with intermittent HPSIP use.

The actions taken and the decisions made by the operator during the event were reasonable and prudent. The decision to ramp down the unit prior to tripping prevented the activation of the ADVs and/or SVs, thus keeping radioactive releases as low as possible.

Several operator actions may have complicated the course of events. These are the following:

(1) The RCP in the loop containing the damaged SG was tripped. This should not have appreciably altered the leak rate, the SG pressure or level, or the RCS cooldown; therefore, there was no need for this action.

(2) According to the licensee's sequence of events, the damaged SG received feedwater for about 10 min after the MSIV was shut. Also, the RCS depressurization (time until equalization across the damaged SG) took about an hour after the reactor was tripped. These actions could have contributed to the excessive level in the damaged SG.

7.1.3 Radiological Considerations

A small quantity of radioactivity was released to the environment during the initial period of the event. The total release to the environment through the air ejector and the blowdown tank vent was evaluated by the licensee to be less than 2265 Ci of Xe-133 equivalent over a 68-min period. This total release represents a small fraction of the potential radiological consequences that could have resulted from relieving the pressure of the faulted SG directly to the environment through the SVs or ADVs.

The staff did not perform a detailed independent analysis of the radiological consequences for this event. However, our detailed analysis of the Prairie Island Unit 1 accident, as well as our review of the licensee's data, indicates general agreement with the licensee's conclusions concerning the actual releases for this accident.

7.1.4 Summary

The evaluation resulted in the following findings:

(1) Limited specific information exists regarding systems performance and plant operator response.

(2) The leak was caused by a combination of wasteage and stress corrosion.

(3) The SGT leak was sufficiently small to allow a controlled unloading of the plant, which avoided an automatic scram, possible SIS actuation, and actuation of the SG ADVs.

(4) The plant was cooled and depressurized very slowly. The persistent primary-to-secondary system leak may have contributed to the excessive level in the damaged SG.

(5) Feed flow to the damaged SG was not, apparently, expeditiously secured. This was probably the main cause for the excessive level.

(6) The RCP in the affected loop was tripped and had to be restarted to restore pressurizer spray from that loop.

(7) Various radiation monitors did not operate properly as a result of their location or circuitry. The specific problems were corrected.

7.2 Surry Unit 2

7.2.1 Systems Performance

The actual SGT rupture was smaller than the one assumed in the FSAR analysis; therefore, the leak rate was lower and the response of the various systems was somewhat different.

The staff analyzed the performance of the various important plant systems during the actual SGT rupture event to ensure their performance was adequate and within the bounds of that predicted in the safety analyses. Plant performance was reviewed to ensure that no unexpected behavior had occurred.

7.2.1.1 Reactor Coolant System

7.2.1.1.1 Pressure and Pressurizer Level

The actual SGT leak rate was reported to be significantly less than that predicted in the FSAR analysis. The licensee estimated the SGT leak rate at 80 gal/min. Based on the initial rate of VCT makeup, this rate seems justifiable. However, the rate of L_p and P_p decreases indicate a somewhat higher leak rate, especially with two charging pumps at full speed injecting mass into the system and with letdown isolated. As the detailed event sequence states, the second charging pump was started and letdown was isolated within about 5 min after the air ejector high-radiation monitor alarm was actuated.

The staff performed scoping calculations to estimate the leak rate through the ruptured SGT. This calculation was based on data obtained from the licensee showing the response of key RCS parameters as a function of time. The data obtained from strip chart recordings were subject to some interpretation since the actual point of reactor trip was not indicated and the time scale was compressed to an extent that the determination of the rate of change of parameters is at best accurate to ±20%. Also, the licensee has stated that the leak rate was very low initially and was barely apparent. The calculated leak rate using the best estimate is 330 gal/min. This is based on the following conditions and assumptions at the time period prior to commencing load reduction at 10%/min:

Charging flow (assumed)	175 gal/min
Letdown	60 gal/min
T_{AVE} (assumed)	Constant
Rate of change of L_p	-2.4%/min
Rate of change of P_p	-21 psi/min

Because the FSAR analysis did not explicitly give the expected SGT leak rate, the staff calculated the approximate leak rate based on the L_p decrease before the unit tripped on low P_p (the subsequent RCS cooldown adds significantly to the rate of L_p decrease and complicates the calculations of leak rate). The staff calculated the FSAR leak rate to be approximately 920 gal/min.

The SGT rupture caused values of both L_p and P_p to drop very quickly. The strip charts show that initially L_p was decreasing at 2.4%/min and P_p at 21 psi/min. This level decrease caused the charging pump to automatically increase flow to its maximum of about 175 gal/min. The normal charging flow is 69 gal/min. The operator, seeing the level continue to fall, secured letdown and manually started the second charging pump. The level did not begin to increase although its rate of decrease had slowed down. At this point the operator started to ramp down load at 10%/min and began emergency boration by aligning the charging pump suction to the boric acid transfer pumps. Simultaneously, the charging pumps were taking suction from the RWST as a result of the low level in the VCT. The plant was manually tripped from 70% power. This caused L_p to go off the scale at the low end and P_p to drop sharply to 1800 psi. At this point SI was initiated manually.

The automatic trip and SI were precluded by prompt operator action. Had the operator not taken the actions described, the reactor would have automatically tripped when the low pressure setpoint of 1860 psi was reached. The automatic trip would have occurred some 18.5 min after the accident, based on the rate of depressurization of 21 psi/min. The operator tripped the reactor 8.5 min prior to the occurrence of the automatic trip. The SI was also manually initiated by the operator 1 min after the trip because of the loss of L_p and rapid decrease in P_p following the reactor trip. At that time SI would have been automatically initiated on a coincidence of $L_p < 5\%$ and $P_p < 1700$ psi. The P_p condition would have been satisfied 17 min after the event, and the second condition probably would have been satisfied when the reactor automatically tripped 18.5 min after the accident. The operator action mitigated this event.

The SI flow caused a rapid rise in the values of both L_p and P_p, 2.7%/min and 43 psi/min, respectively. The operator reset the SI signal when the 5-min delay timer expired. The purpose of this timer is to prevent the operator from resetting the SI actuation signal (SIAS) for 5 min after initiation. After resetting the SIAS, the operator secured both LPSIP and one charging pump. The remaining charging pump was then realigned through the normal charging path. The P_p began to fall again at 21 psi/min, and L_p began to fall at 1%/min. The operator restarted the other charging pump and realigned the flow from both charging pumps back through the SI flow path. The level returned in the pressurizer and was maintained at approximately 20%. During this interval SG "A" was isolated by securing all feed flow and closing the MSIV, and the plant was depressurized and cooled with the intact SGs.

Because the operator was unable to reset the SIAS for 5 min, the P_p returned to 2100 psi. Although this is desirable from the standpoint of maintaining an adequate subcooling margin in the core, it does increase the integrated primary-to-secondary system side flow and hence the activity on the secondary side. Because the air ejector was discharging into the containment, this did not contribute to any release of activity to the environment.

This incident is less severe than the complete SGT severance analyzed in the FSAR. The FSAR states that the operator has approximately 1/2 h to terminate the SGT break flow under worst-case conditions (three charging pumps running) before the SG is flooded to the main steam lines.

The sequence of events shows that the operators were able to isolate the affected SG within 18 min following the initial high radiation alarm actuation for the air ejector discharge. Although the RCP was not stopped in the affected loop and the loop isolation valves were not closed to terminate the break flow as indicated in the FSAR, the operators were able to control the level in the affected SG by depressurization of the primary system. The RCS was at 1000 psig 1 h after the reactor trip. While exact numerical comparisons are difficult to make because of the quality of data recorded by the plant and because operator action was somewhat different than anticipated, it appears that the trends of P_p and L_p are similar to those presented in the FSAR for the case in which two SI pumps are running and full auxiliary feed flow is available.

To assess the plant and operator responses during the actual accident, the staff has performed scoping studies in which the times required for the reactor to scram and for the SIS to actuate are compared. The comparisons were made for three cases and for two leak rates.

In Case 1 it is assumed that the operator does not take any action until the reactor scrams and SIS actuation occurs.

In Case 2 it is assumed that the operator instantaneously recognizes the accident and takes immediate actions aimed at preventing the depletion of the primary coolant inventory.

In Case 3 the actual sequence of operator actions is assumed. The scram and SIS actuation times calculated in this case are slightly different from the actual times because of some simplifying assumptions made by the staff. These same assumptions were made for other plant scoping calculations; the results are therefore comparable.

The calculations were made for the leak rate corresponding to the actual accident and for the rate assumed in the FSAR. The results are shown in Tables 4 and 5.

7.2.1.1.2 Boron Concentration

A strip chart of source range nuclear instrumentation shows that a shutdown margin continued to be maintained and was increasing even as the plant was being cooled. Plant procedures required a minimum boron concentration C_B of 1031 ppm at 100°F RCS temperature. One hour after the reactor trip, C_B was measured to be 1236 ppm; 1 h, 45 min after the accident C_B was measured to be 1356 ppm,

Table 4

Time for RCS pressure to drop from normal (2235 psig) to the low P_p scram (1860 psig)

Case	Time (min)	
	FSAR-calculated leak rate of 920 gal/min	Staff-estimated leak rate of 330 gal/min
1	4.5	15.3
2	5.3	30.0
3	NA	25.2

Table 5

Time for RCS pressure to drop from the low P_p scram (1860 psig) to the low P_p SIS setpoint (1700 psig)

Case	Time (s)	
	FSAR-calculated leak rate of 920 gal/min	staff-estimated leak rate of 330 gal/min
1	40	60
2	41.7	60
3	NA	No scram

and the T_H was still greater than 350°F. Therefore, the plant boration capability was more than adequate to maintain a shutdown margin.

The staff calculated the effect of diluting the RCS boron concentration with secondary unborated water after equalization of pressure across the SGTs and reduction of RCS pressure as system cooldown and depressurization continue. The calculations are shown in Appendix D and were performed for a two-loop Westinghouse PWR, Prairie Island. These calculations are highly conservative in that they assume the secondary liquid contains no boron and is completely returned to the primary system; therefore, the dilutions and resulting reactivities shown represent the worst possible case in terms of dilution. The staff's calculations show that for Prairie Island an adequate shutdown margin is maintained. Since the Surry plant has a larger RCS and smaller SG volume, consequences of boron dilution are bounded by the Prairie Island calculations. Appendix D shows that there was no criticality problem caused by RCS dilution following the SGT rupture event at Prairie Island Unit 1.

7.2.1.1.3 Flow

The removal of core decay heat depends on either forced or natural circulation. The Surry FSAR analysis assumed a LOOP coincident with SI. The RCPs are not powered following a LOOP; therefore, the analysis of record assumes natural circulation. The recovery procedure in the FSAR states that the operator action, assuming OSP is available, should be to trip the RCP in the affected loop and isolate the loop by closing the reactor coolant loop isolation valves.

The Surry plant had the SGT break in SG "A." According to the Control Room Operator (CRO) Log, 10 min after the reactor was tripped, RCP "B" was shut down. Shutdown of RCP "B" is standard operating procedure during a plant cooldown since there are no pressurizer spray lines associated with loop "B," and running this pump puts additional energy into the primary system, which reduces the attainable cooldown rate. However, the staff considers it important to maintain as much RCS flow as possible during the cooldown and concludes that the RCP in the undamaged "B" loop should have remained operating.

Loop "A" was isolated 11 h and 20 min after the reactor trip. Strip-chart recordings of SG level indicate that all SGs were being maintained at about 75% level. Apparently the nonisolation of the affected loop was not a problem; the SG "A" level was remaining constant during plant cooldown and depressurization. Since the MSIV on SG "A" was closed, no additional release to the environment was incurred by failure to follow the FSAR procedure.

7.2.1.2 Safety Injection System

A fully severed SGT at the bottom of the SG in the vicinity of the tube sheet would result in automatic initiation of SI. However, the break at Surry was not as severe as that assumed in the FSAR; therefore, the operator had sufficient time to initiate SI manually. On this plant the high head SI pumps also function as charging pumps and were used in both modes during this incident to reestablish and maintain pressurizer level.

During the normal charging mode the pumps take the suction from the VCT and inject into a cold leg. Upon receipt of the SIAS, the pump suction is diverted to the RWST and the pumps discharge through the boron injection tank (BIT) to each of the three cold legs. For a time the operators also had the charging pump suction simultaneously aligned to the BAT and to the RWST. The BAT has a 12 weight percent concentration of boric acid.

7.2.1.3 Secondary Systems

The control of the SG level and pressure during the SGT rupture event is extremely important in both intact and ruptured SGs. The evaluation of the staff follows.

7.2.1.3.1 SG Pressure Control

The recovery procedure in the FSAR stipulates that the operator should isolate the faulty SG as soon as the pressure in the generator falls below 1100 psig. The faulty SG was isolated by the operators according to procedure as soon as it was determined which SG had the leak. Approximately 7 min after the reactor was tripped, the feed flow to the faulty SG was secured and the MSIV was closed. Closure of the MSIV ended the release of activity to the condenser. The release of activity to the environment was terminated essentially at the start of the incident when a signal indicating high radiation in air ejector discharge automatically transferred this flow to the primary containment. The plant was cooled by dumping steam from the intact SGs to the condenser until the RCS pressure and temperature had been reduced to the point that permitted them to go on the RHR system. The operators had no difficulties in cooling the plant, and the cooldown was essentially normal.

7.2.1.3.2 SG Level Control

The level in the damaged SG must be controlled to avoid overfilling. Excess water in the affected SG could lead to filling the steam lines, which are not designed for dead weight water loads. Because the operators quickly terminated feed flow to the faulty SG, the SG had a greater margin to accommodate leakage from the RCS into and through the ruptured tube. Leakage from the RCS can be controlled in two ways at Surry: depressurization of the primary system and isolation of the faulty SG by closing the reactor coolant loop isolation valves. An entry in the Shift Supervisor's Log shows that 1 h after the reactor trip the RCS pressure had been reduced to 1000 psig, which is below the lowest setpoint of any main steam line code SV. Therefore, there was no possibility of a discharge to the atmosphere via the secondary SVs since the pressure in the faulty SG can be no greater than the 1000 psi in the RCS. The level in the faulty SG is difficult to read but it appears to be stabilized at about 75% about 1 h after the reactor trip. In any event, the operators apparently had no problem controlling level since they did not close the RC loop isolation valves until after the unit was at cold shutdown, about 11 h after the reactor trip.

7.2.1.4 Miscellaneous Systems

The SG blowdown system and the condenser air ejectors are important in an SGT rupture in that they provide potential activity release paths. The response of each system to the SGT rupture is briefly described in the next two paragraphs.

7.2.1.4.1 SG Blowdown

There is no indication that operators received an alarm signal from the blowdown sample radiation monitor. The blowdown of the faulty SG presumably was terminated 15 min after the reactor trip when the Shift Supervisor's Log entry states that SG "A" was isolated.

7.2.1.4.2 Air Ejector

The operators received the high radiation signals from the air ejector discharge, and the discharge automatically shifted to primary containment. This system performed as designed and limited the release of activity to the environment.

7.2.2 Operator Response

The Surry Unit 2 SGT rupture event was a relatively severe event because of the relatively high leak rate and control rod manipulations in progress at the time. These control rod movements initially led the operators to believe that the decrease in pressurizer pressure level was caused by control rod induced changes in T_{AVE}. The staff's evaluation of the operator training, emergency procedure, and overall operator actions follows.

7.2.2.1 Operator Training

Each new licensee candidate and holders of licenses, during the requalification program, receive training in all Surry emergency procedures, including SGT rupture. The training is accomplished by formal classes, informal discussions, and simulator training.

The formal classroom instruction consists of several days of classroom presentation of precautions and limitations of the procedures and technical specifications. Each step of the procedures is discussed as to its intended purpose and the operators' appropriate response and interpretation.

Informal discussions are not required as part of the training program but on-shift discussions regarding emergency procedures may take place among shift personnel during informal or formal shift training.

Simulators built specifically to model the Surry stations are used for operator training in the use of the Surry plant emergency procedures. The training consists of a demonstration of the SGT rupture accident and a step-by-step evaluation. Operator response to the transient is discussed and during the (hands-on) operator participation phase, the operators manipulate plant controls and take corrective actions. The operators are evaluated on their response and use of the emergency procedures in bringing the plant to a controlled and safe condition.

The operators must retrain on the procedures and simulator approximately every year.

7.2.2.2 SGT Rupture Emergency Procedure

The emergency procedure for the SGT rupture event was reviewed by the staff to ensure that actual plant behavior and operator actions were consistent with the procedure in use at that time. Unfortunately, the revision in effect at the time of the event could not be located. Discussions with the NRC Resident Inspector revealed that the present procedure does not significantly differ from the procedure in effect then, so the staff used the present version. It should be noted that this procedure reflects the staff's requirements specified in NRC Bulletin 79-06A and NRC Bulletin 79-06B regarding RCP trip following SIS actuation and avoiding saturation conditions in the RCS. Judging from the present SGT rupture procedure, the procedures in effect at the time of the event were sufficiently detailed to ensure the operator's ability to conclude an SGT rupture had occurred. Appropriate operator actions are contained in the procedure along with adequate cautions and guidance regarding the void formations, saturation conditions, and identification of the affected SG.

The staff is unaware of any procedural changes made by the licensee as a direct result of the occurrence. Review of the present procedures uncovered the following deficiencies:

(1) The present procedure addresses operator response to a large SGT failure and the associated automatic responses. Operator guidance is not provided for orderly plant shutdown in the event the SGT failure is small enough to be controlled (i.e., within the capacity of the charging pumps).

(2) As the result of Inspection and Enforcement Bulletins, NRC requires the tripping of all RCPs upon SIS actuation and RCS pressure drop below a predetermined value (see NUREG-0623).

(3) Procedural guidance is not included for the following facets of plant operation:

  (a) Use of a PORV on the pressurizer with appropriate monitoring and control of the pressurizer relief tank parameters

  (b) Procedural requirements regarding the canceling of the Phase A containment isolation signal, resulting from the SI signal, to establish auxiliary spray to the pressurizer for pressure control and cooldown if necessary

  (c) Primary systems parameters and conditions required for the restart of an RCP.

(4) Immediate operator action requirements should include verification that the pressurizer PORV is closed or isolated.

(5) The procedure should guide the operator to potential secondary system radioactive release points:

  (a) Steam exhausting from the turbine of the TD AFP--the use of the TD AFP should be minimized; operating times should be tracked (logged) to account for radioactive release

(b) Turbine building sumps, drains, and other potential secondary release points

7.2.2.3 Operator Actions

The operator response to the Surry Unit 2 event is described in Appendix B. The tube rupture was readily apparent, and the operator responded to the symptoms of the procedure in an appropriate manner. Operator judgment was exercised in the early stages of the transient evolution that was not specifically addressed in the emergency procedure:

(1) Attempted to maintain RCS inventory (pressurizer level) by maximizing charging flow to the RCS--manually started additional charging pumps and isolated letdown from the RCS

(2) Initiated turbine load reduction at a rate of 10%/min to bring about an orderly plant shutdown

(3) Borated the RCS in anticipation of plant shutdown

(4) Recognized that the size of the SGT rupture was such that RCS pressure and pressurizer level were not controllable and that the plant was approaching the SI actuation setpoint--manually tripped the plant and initiated SI

None of the above operator actions was detrimental to plant safety; all attempts were made to maintain as orderly a plant shutdown as possible.

7.2.3 Radiological Considerations

As in the case of Point Beach Unit 1, the air ejector radiation monitor provided early indication of a primary-to-secondary system coolant leak. In another parallel to the Point Beach Unit 1 accident, the SG blowdown radiation monitor did not provide useful information for the early identification of the faulty SG. Since the steam dump valves and SVs of the faulted SG did not actuate during this accident, the radiological consequences of the event are very small. In addition, release of radioactivity to the environs was minimized by automatic diversion of the air ejector discharge to the reactor containment.

The staff did not perform an independent analysis of the releases from this accident, but, based on the licensee's analysis, the consequences are believed to be much lower than those of Prairie Island Unit 1 (see Section 7.3).

7.2.4 Summary

The evaluation resulted in the following findings:

(1) Limited specific information exists regarding systems performance.

(2) The leak was caused by stress corrosion cracking in the U-bend portion of the Row 1 tube.

(3) Radiation alarms functioned as expected, and air ejector discharge was automatically shifted to primary containment, thus quickly terminating any release of activity to the environment.

(4) Operator action mitigated the accident. Further mitigation could have been achieved by tripping the RCP in the affected loop and closing the loop isolation valves. Not isolating the affected RCS loop, however, hastened the damaged SG cooldown and depressurization.

(5) The operators diagnosed the problem quickly and isolated the secondary side of the affected SG.

(6) The RCP in the faulty loop was not tripped, and the loop isolation valves were not closed until the plant was in cold shutdown.

(7) The RCP in an intact loop was tripped to reduce RCS thermal inputs. This did not affect pressurizer spray.

(8) The plant was brought to cold shutdown in about 11 h in an essentially normal cooldown.

(9) Manual initiation of SI caused a rapid repressurization of the primary system and restored level in the pressurizer.

7.3 Prairie Island Unit 1

7.3.1 Systems Performance

The FSAR contained only a very sketchy description of the basis for the analyses of the SGT rupture event. Since practically no quantitative information was available it was difficult to make the detailed comparison between the performance of different systems during the actual event and the performance assumed in the FSAR analyses. Faced with this problem, the staff could perform only a limited scope analysis, which would not reflect all the differences that may exist between the actual and the FSAR described event.

The staff analyzed the performance of the various plant systems during the actual SGT rupture event to ensure that their performance was within the FSAR-predicted performance and to see whether any previously unknown or unexpected plant behavior was experienced.

7.3.1.1 Reactor Coolant System

7.3.1.1.1 Pressure and Pressurizer Level

The actual leak rate between the primary and secondary systems was calculated from the pressurizer level changes provided in the report of the licensee to the staff. This value was corrected to account for the pressure differential across the break existing at the beginning of the accident. The corrected value is 33.5 lb/s (336 gal/min). The corresponding leakage rate assumed in the FSAR analysis was not available; however, it was calculated from the total assumed primary water leaked into the secondary side of the faulty steam SG before the plant was depressurized and the pressure differential across the break dropped to zero. Assuming a linear change of the pressure differential with time, the initial leak rate was calculated to be 100 lb/s (1004 gal/min). The leakage rate assumed in the design basis analysis in the FSAR was, therefore, higher than the actual leakage experienced during the accident.

The first indication of abnormal plant behavior was an intermittent high radiation alarm signal on the air ejector discharge radiation monitor. The operator was initially misled by the intermittent alarm, and could not confirm that an SGT rupture had occurred since pressurizer level and pressure were not changing significantly. This was followed by an increased flow of charging water and, later, about 5 min after the first air ejector radiation monitor alarm signal, by a rapid drop in pressurizer level and pressure. This confirmed that the primary coolant was leaking into the secondary side of one of the SGs. At this point, the operator could not estimate the magnitude of the leak. However, the RCS pressure and level response should have been less severe than predicted in the FSAR because the leak rate was lower. The licensee's abnormal event report indicated that little more than 10 min after the event with all three charging pumps operating the pressurizer level reached its minimum value. The licensee has shown, however, that even at this point some liquid was left in the pressurizer. The RCS pressure also showed considerable decrease, and at about 10 min after the event low pressure (<1900 psig) initiated reactor trip, which was followed by turbine trip. About 5 s later, further decrease of the primary pressure caused actuation of SI (<1815 psig). The SI signal also automatically terminated normal feedwater supply and initiated AFW addition.

To assess the plant and operator responses during the actual accident, the staff has performed scoping studies that compare the times required for the reactor to scram and for the SIS to actuate. The comparison was made for three cases and for two leak rates.

In Case 1 it is assumed that the operator does not take any action until the reactor scrams and SIS actuation occurs.

In Case 2 it is assumed that the operator recognizes instantaneously the accident and takes immediate actions aimed at preventing the depletion of the primary coolant inventory.

In Case 3 the actual sequence of operator actions is assumed. The scram and SIS actuation times calculated in this case are slightly different from the actual times because of some simplifying assumptions made by the staff. These same assumptions were made for other plant scoping calculations; the results are therefore comparable.

The calculations were made for the leak rate corresponding to the actual accident and for the rate assumed in the FSAR. The results are in Tables 6 and 7.

From the plots provided by the licensee, the staff estimated that during the first 10 min of the event, before reactor trip and SI were initiated, the primary coolant inventory was reduced by about 2000 gal. Immediately after the start of injection flow provided by two SI pumps (1400 gal/min), the inventory of the primary system started to increase. This caused an increase in the primary system pressure that eventually reached 2000 psig at about 13 min after the start of injection flow. Pressurizer level also started to rise, reaching approximately the 57% level. At this point, the operator started to reduce

Table 6

Time for RCS pressure to drop from normal (2235 psig) to the low P_p scram (1900 psig)

Case	Time (min)	
	FSAR-calculated leak rate of 1000 gal/min	Staff-estimated leak rate of 336 gal/min
1	2.4	7.9
2	2.8	15.8
3	Same as Case 1	Same as Case 1

Table 7

Time for RCS pressure to drop from the low P_p scram (1900 psig) to the low P_p SIS setpoint (1815 psig)

Case	Time (s)	
	FSAR-calculated leak rate of 1000 gal/min	Staff-estimated leak rate of 336 gal/min
1	22	38
2	25.3	47
3	Same as Case 1	Same as Case 1

the primary system pressure. Since cooldown rates using only one SG were not sufficient to control the pressure, the operator stopped one SI pump and started to depressurize using the PORVs on the pressurizer. This was the only means of depressurization left to him since the main coolant pumps were stopped and spray cooling of the pressurizer was not available. The use of PORVs for pressure relief during the steam line break accident was considered in the FSAR analysis for the case of concurrent loss of OSP. The flow of steam through the PORVs generated high pressure in the pressurizer relief tank and caused the rupture disk to burst. However, this event did not cause any serious consequences since the contaminated liquid did not leave the containment buildings.

Ten minutes after starting to depressurize the plant, the operator stopped the second SI pump in an attempt to increase the rate of pressure reduction. This action was justifiable because he still was able to maintain a sufficiently high degree of subcooling. Sixty-one minutes after the beginning of the accident, the primary and secondary pressures were equalized and leakage through the break stopped. The time the primary coolant was leaking through the break was twice as long as assumed in the FSAR. The staff estimated, from the information provided by the licensee, that the total amount of primary coolant leaked to the secondary system was 160,000 lb. This was about 33% more than assumed in the FSAR analysis; however, the damaged SG was isolated 27 min after the beginning of the accident, thus preventing any release of contaminated water since the ADVs and SVs remained closed.

7.3.1.1.2 Boron Concentration

The analysis of SGT rupture presented in the FSAR does not address directly the problem of boron dilution in the primary coolant system. However, the reference to the use of the SI pumps indicates that credit was taken for high concentration boric acid solution injected into the primary coolant system. In the evaluation of the actual event, the licensee states that two BATs were used to raise boric acid concentration because of some draining of SG water into the RCS. The licensee states further that a sufficiently high boron concentration was established in the shell side of the damaged SG through the primary-to-secondary system leakage at the beginning of the event as insurance against problems with RCS dilution during the cooldown when eventually the secondary pressure may exceed the RCS pressure. The licensee does not provide any quantitative information in support of this.

The concentration of boron in the primary system starts to increase as soon as the SI pumps start to inject highly concentrated boric acid solution. The staff has estimated that toward the end of the SI period (when both SI pumps are stopped) the injected boron would raise boron concentration in the primary coolant to a level higher than 3000 ppm, assuming no inleakage of the secondary water. The staff's analysis presented in Appendix D indicates that, for this boron concentration, dilutions as high as 50% can be tolerated without danger of introducing enough positive reactivity to make the reactor critical. In the actual case such high dilution rates are not possible. The staff's analysis is therefore very conservative and it indicates that the criticality problem resulting from boron dilution never existed during the SGT rupture accident at Prairie Island Unit 1.

7.3.1.1.3 Flow

The analysis presented in the FSAR does not require the main coolant pumps to be stopped during an SGT rupture event. However, following the requirement of Bulletin 79-06C, the licensee switched off the pumps immediately after the SI signal was initiated by low pressurizer pressure. The pump in loop "A" was switched off 12 min after the beginning of the accident, and the pump in loop "B" 1 min later. After the pumps were switched off, the flow diminished gradually before stopping, and then natural circulation flow was established in the RCS. The driving force for the flow was provided by the temperature differentials existing across the core and across the undamaged SG. The staff has estimated that 30 min after the beginning of the accident, the natural circulation flow was equal to approximately 5% of the flow that would have existed had both main coolant pumps remained in operation. Stopping the pumps had a deleterious effect on plant cooldown. It also did not permit the use of normal pressurizer spray for plant depressurization.

The licensee has stated in the Licensee Event Report (LER) that, for natural circulation flow, a cooldown rate of the order of 50°F/h was expected with a value of ΔT across the SG of approximately 30°F. The staff has performed an RCS cooldown comparison with and without main coolant pumps operating and found that without the pumps, the RCS temperature after 30 min was higher by about 20°F.

7.3.1.2 Safety Injection System

According to the analysis presented in the FSAR, the SIS is required during the SGT rupture accident to both recover and control RCS pressure and pressurizer level and to provide RCS boration, if needed. The FSAR assumed that the SIS is initiated by the coincident low pressurizer pressure and low pressurizer level signals (<1815 psig and <5% level). The SI signal starts two motor-operated SIPs, each having a capacity of 700 gal/min. The pumps are initially aligned to draw liquid from the BATs containing 20,000 ppm boric acid solution. At Prairie Island, three BATs are shared between the two units. After depletion of boric acid solution in the tanks, the SIPs automatically switch to the RWST and continue to draw water from it. The FSAR requires that after recovery of pressurizer level, one SIP be stopped and the other one operate for 30 min until the pressures between primary and secondary sides of the damaged SG are equalized.

During the actual accident, the SIS was initiated 5 s after the reactor trip. It was initiated by low pressurizer pressure only (<1815 psig) and not by low pressurizer pressure and level, as assumed in the FSAR analysis.* However, when the actuation pressure of 1815 psig was reached, the pressurizer level was already below the 5% level required for SIAS in the FSAR, so even if two coincident signals were required, the SI initiation time would be the same. One SIP was stopped immediately after the pressurizer level returned on scale. The other pump was stopped 10 min later, when the level reached the high level setpoint (>55%), about 9 min before the primary and secondary pressures equalized.

*As a result of the TMI-2 investigations, the SIS actuation logic was changed so that actuation would occur on low pressurizer pressure without low pressurizer level.

7.3.1.3 Secondary Systems: SG Pressure and Level Control

The FSAR analysis states that, when the faulty SG has been identified, AFW flow to this unit should be stopped and the unit should be isolated by closing the MSIV on the affected line. The undamaged SG should then be used as a heat sink and the steam should be bypassed to the condenser. However, the analysis considers also the conservative case of the loss of OSP when the condenser is unavailable and the steam is dumped to atmosphere with the SG controlled at the SV set pressure rather than the set pressure of the 5-in. air-operated relief valve.

During the actual accident, following the reactor and turbine trip, the bulk of steam from both SGs was discharged to the condenser. Some small amount of steam was released to atmosphere from the turbine used to drive the AFP. However, the operator recognized this source of release early in the event and shut the steam supply valve from the damaged SG. As a result, only a relatively small quantity of radioactive fluid was released to the atmosphere. Some steam was also released through one of the two ADVs in the affected line that opened for 3 s after the reactor trip. The licensee has estimated that the combined release from both these sources amounted to about 5000 lb of steam.

The operator identified the faulty SG about 18.5 min after the beginning of the accident. He identified it by steam/auxiliary-feed mismatch and by its rapid level recovery following the reactor trip. The AFW to the damaged SG was then discontinued as soon as possible after SI reset (in 24 to 27 min). Steam from the damaged SG was isolated from the rest of the steam systems 27 min after the start of the accident when the MSIV in the affected line (loop "A") was closed. After the isolation, its pressure remained below the settings of the safety and air-operated relief valves, and no steam was released. The actual event was, therefore, bounded by the FSAR analysis where some release after the isolation was postulated. About the time the damaged SG MSIV was manually shut, the MSIV in the intact SG was automatically closed, presumably by a signal generated by the high steaming rate (concurrent with SI signal and low T_{AVE}).

However, the operator immediately opened the MSIV and this SG was used as a main heat sink for subsequent cooling and depressurization of the plant until the proper pressure and temperature conditions were reached for placing in service the RHR system and for continuing cooling to cold shutdown. To increase cooldown rate, the main coolant pump in the unaffected loop (loop "B") was restarted about 7 h after the beginning of the event. However, the fact that the pumps were not operating during the greatest part of the event contributed to the slow cooldown rates and caused the equalization of the primary and secondary system pressures across the affected SG to take 31 min longer than assumed in the FSAR analysis.

7.3.1.4 Miscellaneous Systems

The air ejector and the SG blowdown systems play significant roles in the worst of the SGT rupture event. Radiation monitors in these systems can detect activity level increase in the secondary system and can identify leakage of the primary coolant through the tube break into the secondary system.

7.3.1.4.1 SG Blowdown

Although the FSAR analysis assumes that the radiation alarm on the SGB system is functional, the licensee could not use it in identifying the SGT rupture event because the alarm never actuated.

7.3.1.4.2 Air Ejector

The discharge of the steam air ejector is monitored for radioactivity by the special radiation monitor. This monitor started the alarm that first warned the operator about the abnormal plant operation and allowed him to diagnose the SGT rupture event.

7.3.2 Operator Response

The Prairie Island Unit 1 SGT rupture event was a relatively severe event in that there was little or no time for the operator to take action to prevent the rapid loss of RCS pressure and level. The system automatically tripped and the SIS was automatically initiated. The operator actions should have closely paralleled those assumed in the analysis of record since the systems behaved similar to the manner assumed in the analysis. The staff's evaluation of the operator training, emergency procedure, and overall operator actions follows.

7.3.2.1 Operator Training

Prairie Island emergency procedure training consists of formal training classes conducted as part of the requalification program. Oral exams are conducted on the emergency procedures including SGT rupture. Informal on-shift discussions are not required as part of the ongoing training.

The Prairie Island nuclear power units do not have a site-specific simulator. Simulator training to meet the operator requalification requirements of the site is accomplished through the use of other PWR simulators such as Indian Point, Sequoyah, or Zion. Actual site-specific procedures are used during simulator training on emergency procedures. Minor variations are incorporated to accommodate the difference between the actual site and simulator control boards and plant systems. Discussions with the training coordinator indicate the use of site-specific emergency procedures works well, and the operators are satisfied with their ability to use the guidance provided in the procedure to diagnose and control satisfactorily the SGT ruptures.

The operators must retrain on the plant emergency procedures and on the simulator during the requalification program.

7.3.2.2 SGT Rupture Emergency Procedure

The emergency procedure for the SGT rupture event was reviewed by the staff to ensure that actual plant behavior, procedural requirements, and operator actions were consistent. The staff used the actual procedure in effect at the time of the event. This procedure reflects the current staff requirements regarding RCP trips, SIS operation, and RCS subcooling. These requirements were in effect at the time of the event.

Two procedures are relevant for the SGT rupture event: EI.0 dated May 31, 1979, entitled "Safety Injection Initiation" and EI.3 dated May 31, 1979, entitled "Steam Generator Tube Rupture." In general, the combination of procedures EI.0 and EI.3 provides sufficient operator guidance to bring the plant to a safe shutdown condition.

Appropriate operator actions are contained in the procedure with guidance to assure RCS pressure and temperature relations for saturation conditions and SI operation. As the result of the SGT rupture accident and the operator response at Prairie Island, the following procedural deficiencies were identified by the staff:

(1) If the PORV on the pressurizer is to be used to control RCS pressure excursions, procedural guidance should be provided to the operator for monitoring and controlling the PRT parameters during manual pressurizer PORV operation.

(2) More direct operator procedural requirements should be provided to control pressure transients and pressurizer cooldown; for example, if possible, when and how to establish auxiliary spray to the pressurizer.

(3) Due to the MSIV closure logic and the related high steam flow setpoint, the procedure should caution the operator, during steam dump operation cooldown, to control steam flow below the main steam line isolation setpo...

(4) The procedure should key the operator to appropriate actions during small (controllable) tube failure conditions for orderly load reduction and plant shutdown. If the loss of pressurizer level cannot be controlled and the indicated level is at or is rapidly approaching 0% with pressurizer pressure still above the low-pressure scram setting, a manual reactor trip should be initiated.

(5) The procedure should alert the operator to potential secondary system radioactive release points; that is, to securing or minimizing the use of the steam-driven AFPs and identifying other potential secondary release points.

7.3.2.3 Operator Actions

The operator response to the Prairie Island Unit 1 event is described in Appendix B. The SGT rupture at Prairie Island Unit 1 was readily apparent from a high radiation alarm signal on the condenser steam jet air ejector exhaust and a rapidly decreasing pressurizer pressure and level.

The magnitude of the SGT rupture did not allow time for the operator to respond and maintain RCS inventory (pressurizer level) by isolating RCS letdown and increasing charging flow. The pressurizer level decreased off-scale low (about 37 s) prior to the low P_R automatic trip. The operator did not manually trip the reactor with this condition. The rapidly decreasing pressure caused an automatic reactor and turbine trip immediately followed by SI. This resulted in a rapidly increasing RCS pressure caused by the high head SIP discharge pressure. As required by <u>I&E</u> <u>Bulletin</u> <u>79-06C</u>, the operator tripped both RCPs upon SI with the resulting loss of pressurizer spray capability. To reduce RCS pressure, the operator, using personal judgment, opened the pressurizer PORV. This eventually resulted in the rupturing of the pressurizer relief tank rupture disk and a release into containment.

The actions taken by the operator deviated slightly from the existing emergency procedure at the time of the event. The procedure did not call for controlling system pressure by the use of the PORV. However, due to the requirement of tripping the RCPs upon automatic SI, the operator had no other means of RCS pressure control. The operator's judgment in using the PORV was successful in bringing the plant to a safe shutdown condition. Upon recognizing that pressurizer level was off scale (low) and pressurizer pressure was decreasing, but still above the low-pressure automatic reactor trip, a manual reactor trip would have been prudent. The resident inspector was in the control room at the time of the Prairie Island SGT rupture and SI. He indicated during subsequent discussions that following SI the operator properly followed and adhered to the procedure.

7.3.3 Radiological Considerations

The first indication of a large primary-to-secondary system leak at Prairie Island Unit 1 was a high activity alarm by the air ejector radiation monitor. This was one of six paths for potential releases of radioisotopes resulting from the accident. The major sources of airborne releases were the brief release of steam through the ADVs of the faulted SG and the vent of the AFW turbine. Minor releases are assumed to have occurred via the turbine gland seal exhaust and via leakage from the containment although no specific data are available for this release path. The release from the reactor containment is considered negligible, based on the relatively small amount of activity released to the containment. Another potential release path exists via liquid processing in the secondary system, including building sumps, drains, and tank vents. However, there is no indication that any uncontrolled releases occurred via this pathway as a result of the accident. The licensee estimates that a total of about 30 Ci of Xe-133 equivalent of noble gases and about 1 μCi of I-131 were released via AFW turbine, steam dump valves, and air ejector pathways. This would have resulted in a dose of 13 μrem to the whole body and 23 nrem to the thyroid at the exclusion area boundary (LER of October 16, 1979), assuming the atmosphere dilution factor estimated for the time of the accident.

The staff estimated the total dose to the thyroid during the accident. Analysis assumptions are shown in Table 8, and the results of analysis are shown in Table 9. A comparison of staff estimates of the actual releases of iodine with those estimated by the licensee shows that the licensee may have underestimated actual releases by more than two orders of magnitude. The staff estmiates a release of 210 μCi of dose equivalent (DE) I-131; the licensee estimated 1.2 μCi.

The casue of these large differences is the staff's assumption regarding the various release paths. Since there was no radiation monitoring equipment at the major release points, the licensee could not determine the actual activity released. The staff, therefore, made conservative estimates for these release quantities. In aprticular, an overall decontamination factor of 100 for iodine released from the SG was assumed by the staff, compared to a factor of 2000

Table 8

Assumptions used in the analysis of the SGT rupture event at Prairie Island Unit 1

Parameter	Value
Power level at time of accident	1650 MWt
Time of tube failure	0 min
Time of reactor and turbine trip	10 min
Time of SI activation	10 min
ADV operation	10.0 to 10.05 min
Time of failed SG isolation	27 min
Initial primary-to-secondary system leakage (0 to 10 min)	567 gal/min*
Primary coolant activity prior to accident (I-131 equivalent)	25 nCi/g
Fission product release to primary coolant prior to trip	3.45 mCi/min
Fission product release to primary coolant after trip	0 μCi/min
Atmospheric dispersion parameter (χ/Q)	40 $\mu s/m^3$
Release pathways assumed in analysis	ADV operation TD AFP exhaust Air ejector discharge
Iodine decontamination factor for SG	100

*This was the staff's initial estimate of the leak rate. Later calculation reduced this to around 336 gal/min; however, the reduction would not significantly affect the calculated thyroid doses shown in Table 9.

Table 9

Results of analysis of the release of radioiodine during the Prairie Island Unit 1 SGT rupture event

	Thyroid dose (μrem)	
Time interval (min)	With offsite power	Without offsite power
0 to 10.0	0.0120	5220
10.0 to 10.05	0.432	17.7
10.05 to 27.0	3.86	283
27.0 to 40.0	0.0286	8.61
Total	4.33	5530

assumed by the licensee. (It should be noted that the staff considers its estimate as a conservative upper bound.) Because recurrence of SGT rupture accidents cannot be ruled out, it appears imperative to assure reasonably accurate measurement of the releases to the environs resulting from such an accident by installation of reliable radiation monitoring equipment at all release points.

Notwithstanding the sizable difference in estimated releases, the staff concurs with the licensee's conclusion that the offsite radiological consequences of the Prairie Island Unit 1 SGT rupture accident are small. The staff concludes that the offsite doses did not exceed 10 CFR Part 20 limits.

The results of the calculation with the assumed LOOP, however, show that, with all other parameters unchanged from the actual event, significant offsite doses could have occurred if OSP had not been available during the accident. Staff analysis shows an increase by about a factor of 1000 would have been possible under a LOOP. This large increase in the radiological consequences of this accident is caused by the necessity to remove decay heat from the core by atmospheric steam dump. These consequences, therefore, could result not only from a LOOP, but also from a number of malfunctions that affect condenser vacuum, the bypass system availability, or the ADV itself.

However, even if there had been a LOOP or a malfunction of the ADV itself (resulting in continued damaged SG blowdown for about 30 min), and if the RCS activity had been 1 μCi/g I-131 DE, the offsite dose at the site boundary would have been about 10% of the 10 CFR 100 guideline.

It should be noted to the credit of the operators that skillful plant cooldown operations following identification of the SGT rupture accident avoided large releases by ADV operation.

7.3.4 Summary

The evaluation resulted in the following findings:

(1) The leak resulted from mechanical damage caused by a piece of wire lodged between the tubes in the shell side of the loop "A" SG.

(2) The event was not immediately identified due to the misleading indication of the high radiation alarm on the air ejector discharge radiation monitor.

(3) The leak was of sufficient magnitude to cause the reactor to scram and the SI to start on low pressurizer pressure.

(4) Stopping the main coolant pumps 2 min after the reactor initiation of SI retarded plant cooldown and required use of the PORV for plant depressurization because the normal pressurizer spray was not available.

(5) Equalization of the primary and secondary pressures took twice as long as was assumed in the FSAR analysis.

(6) The dilution of primary system boron concentration by the inflowing secondary water did not cause any serious reactor criticality problems.

(7) The plant was successfully brought to cold shutdown condition.

7.4 Plant Comparisons

The various predictions, findings, and responses of the three plants are compared in this section. The results for each of the major evaluation categories are separately compared.

7.4.1 Systems Performance

Tables 10 and 11 provide comparisons of the various system performances for the Point Beach Unit 1, Surry Unit 2, and Prairie Island Unit 1 SGT rupture events (predicted and actual).

7.4.1.1 Leak Rates

The difference in plant volume, SGT size, and scram setpoint are apparent in the predictions for the time to reach the low P_p scram setpoint with the FSAR design leak rate. The Point Beach FFDSAR states that the leak rate is initially 80 lbm/s and then rapidly drops to 40 lbm/s. It could not be determined how quickly the mass flow rate dropped; therefore, the staff's estimate (for time to reach the low P_p scram) is based on 80 lbm/s (about 800 gal/min).

Without any operator action, the time to reach the low P_p scram is shortest for Prairie Island Unit 1 since the plant has a relatively small pressurizer volume (compared to Surry Unit 2), a relatively high low P_p scram setpoint, and a high predicted leak rate. Surry Unit 2 has the longest time to reach low P_p scram, although the leak rate is about the same as that of Prairie Island Unit 1, since the pressurizer volume, mass, and heat capacity are larger than either Prairie Island or Point Beach Unit 1.

Table 10

Comparison of Scram times and SIS times

Parameter	Point Beach SAR	Point Beach Actual	Surry SAR	Surry Actual	Prairie Island SAR	Prairie Island Actual
NOP (psig)	2235		2235		2235	
Low P_p scram (psig)	1865		1860		1900	
Low P_p SIS (psig)	1715		1700		1815	
$(T_{AVE})_{FL} - (T_{AVE})_{NL}$ (°F)	31		18		13	
	SAR	Actual	SAR	Actual	SAR	Actual
Leak rate, average* (gal/min)	800	125	920	330	1000	336
Time to scram* (min):						
No operator action	3.3	22.6	4.5	15.3	2.4	7.9
Instantaneous operator action	4.4	None	5.3	30	2.8	15.8
Actual						
Time from Scram to SI*	3.6	None	(†)	25.2	(†)	(†)
(s):						
No operator action	23.0	30.0	40.0	60.0	22.0	38.0
Instantaneous operator action	30.7	NA	42.0	60.0	25.3	47.0
Actual	24.8	NA	(†)	(None)	(†)	(†)

FL = full load; NL = no load.

(†) Same time as Case 1.

* These leak rates and times are from staff scoping calculations.

Table 11

Systems performance comparison

Parameter	Point Beach	Surry	Prairie Island
dP/dt, actual (psi/min)	-	20	81
Time to scram, actual (min)	47*	10*	10†
Power at scram (%)	25	70	90
Time for scram to SIS, actual (s)	None	60*	∿5†
Minimum RCS subcooling, estimated (°F)	-	45	32
Time to shut MSIV (min)	48	17	27
Time to stop feed flow (min)	58	17	?
Post-SIS RCS repressurization rate (psi/min)	-	43	43.8
Post-SIS RCS peak pressure** (psig)	-	2100	2000
Time to pressure equalization across damaged SG (min)	108	>30	61††
Normal spray:			
Flow (gal/min)	300	575	400
dP/dt (psi/min)	88.5	128	118
Normal spray and 1 RCP tripped:			
Flow (gal/min)	≃180	≃420	≃240
dP/dt (psi/min)	53.1	93.5	70.8
PORV:			
Flow (lbm/h)	179 000	179 000	179 000
dP/dt (psi/min)	450	388	450

*Manual.

†Automatic.

**Method of RCS pressure control: Point Beach and Surry use normal spray and RCS cooldown; Prairie Island uses intermittent pressurizer PORV operation and RCS cooldown.

††RCS pressure was below 1000 psig about 40 min after the first high radiation alarm.

The actual leak rate (staff's estimate) for Prairie Island Unit 1 and Surry was about the same, although our estimate of the Surry Unit 2 leak rate was based on poor quality traces. (Our Surry Unit 2 estimate, 330 gal/min, was used to calculate the rate of change of RCS pressure, and this agreed reasonably well with the trace. However, the trace of RCS pressure was equally poor.)

The time to reach the low P_p scram with the staff-predicted leak rates and without any operator action reflects the combined effect of different leak rates, depressurization rates, and the differences between normal operating pressure and low P_p scram. The Point Beach Unit 1 time is the longest since the leak rate was so small, despite the relatively small pressurizer volume, mass, and heaters. The relatively small charging system flow (net charging flow 14.5 gal/min versus 106 gal/min for Surry Unit 2) did not significantly affect the event.

The time to reach low P_p scram was shortest for Prairie Island, which had the largest leak rate (slightly larger than Surry), and a comparatively small charging pump, pressurizer volume, mass, and heater capacity.

The times to reach low P_p SIS setpoints for both the FSAR and the actual leak rates are about equal for Prairie Island and Point Beach Unit 1. This time is strongly influenced by the RCS contraction and subsequent depressurization. The time to reach the low P_p SIS setpoint for Surry Unit 2 reflects the somewhat larger pressure spread between scram and SIS setpoints, and the larger pressurizer.

Should the operator instantly diagnose the problem, start the remaining charging pumps, and isolate letdown, the time to reach low P_p scram increases significantly over the no-operator action cases for all plants, as would be expected. The increase over the FSAR case for Point Beach and Prairie Island Unit 1 is similar, considering the different leak rates. This is expected since they have similar charging systems. The increase in time to scram for Surry is somewhat less, due to the relatively small increase in charging system flow between the no-operator action case (106 gal/min net input) and the instant operator action case (216 gal/min).

The increase in time to scram (over the FSAR) for the actual leak rates for the three plants reflects the effects of leak rate, system volumes, and CVCS characteristics.

The times to scram considering actual CVCS manipulations and the FSAR and actual leak rates lie between the no action and "perfect" operator cases, as expected. The Point Beach Unit 1 case shows that, as expected, there is a net mass input into the system, and the pressure can be controlled. (The staff had no traces of pressure or level to verify the licensee's estimated leak rate.)

The Prairie Island Unit 1 calculations showed that there was no reduction in scram or SI actuation time, since the actual operator actions took place just after the staff's scoping calculations predicted a scram on low P_p. (As stated earlier, these calculations are not intended to exactly predict the plant response, but are used for comparative purposes.)

7.4.1.2 Depressurization Rate

The next set of comparisons shows the actual plant depressurization rates prior to scram during the SGT rupture event. The plant depressurization rate after scram, if the plant was scrammed at a high-power level, were significant and could not be determined from the information available. However, the time to reach automatic SI is shown. The Surry Unit 2 time was derived from a computer log that was operating about 6 min behind real time; therefore, the actual time could be significantly different.

The FSAR, in most cases, assumes the operator is able to distinguish which SG is damaged and isolate it within 10 min following the event. However, the actual leak rates are smaller than the FSAR leak rates, and the damaged SG was, therefore, not so readily apparent. The times when the MSIV on the damaged SG was shut are shown, and these reflect the time when release of contaminated fluid from the SG to the main steam system stops. This is an important time for Point Beach and Prairie Island because it reflects the time when the condenser stops receiving radioactive isotopes. As a result, the air ejectors, shortly thereafter, stop releasing to the environment. It is not significant for Surry, since the air ejector automatic divert feature directs air ejector discharge to the containment upon actuation of the high radiation signal.

7.4.1.3 Repressurization Rate

The staff noted that the system repressurization following SIS actuation is a significant phenomenon. The Surry Unit 2 repressurization rate was twice the depressurization rate (before scram) due to the relatively large-capacity SIPs. The Prairie Island Unit 1 repressurization rate is about the same as Surry since the RCS volume and SIS capacity are smaller than Surry but are proportionally the same. In both cases the operators took action, as the FSARs state must be done, to limit the repressurization and hence the release through the break. The Prairie Island Unit 1 operators opened the pressurizer PORV because normal spray was unavailable due to the RCP trip. This caused the RCS pressure to abruptly turn and drop at a rate of about 400 psig/min. The Surry Unit 2 operators still had normal spray available and were able to use it to control system pressure. The peak pressures for Prairie Island Unit 1 and Surry Unit 2 were 2000 and 2100 psig, respectively. Neither is close to the setpoints for automatic opening of the PORV (2335 psig) or the RCS code SV setpoints (~2500 psig). The staff notes that the RCS repressurization rate is highly plant dependent and would depend on SGT break size, SIP operating characteristics, and RCS volume.

7.4.1.4 Control of Pressure

For all three plants, the depressurization following SIS actuation was aided by the RCS cooldown.

The time to equalize pressure across the damaged SG is important because it represents the point when leakage through the broken tube effectively stops. It should be noted that the FSARs for all three plants state that the operators have the ability and equipment to equalize pressure within 30 min, and it is this time that governs the quantity of steam released through the SV or ADV on the broken SG (analysis assumption). Since no ADV or SV operation occurred (with the exception of a momentary opening at Prairie Island Unit 1), the greater time required to reduce RCS pressure did not result in release to the atmosphere, but did result in greater leakage to the SG.

The staff has calculated the pressurizer depressurization rate assuming, variously, normal spray, auxiliary spray, and PORV actuation. The flow rates through these components are also given. Table 11 shows that, using normal spray, plant pressure can be expeditiously lowered to reduce the ΔP across the broken tubes, and the accompanying primary-to-secondary system leakage.

The auxiliary spray system may not be available post-SIS due to the unavailability of control air inside containment (through isolation). Also, the spray nozzle has a 320°F ΔT limit to minimize thermal shock. This limit may eliminate the use of auxiliary spray to perform plant depressurization soon after the SGT rupture since the auxiliary spray water is more than 320° cooler than the spray nozzle. However, Westinghouse states that the nozzle can withstand a limited number of thermal cycles associated with spraying cold (78°F) water into the hot pressurizer steam space.

7.4.2 Operator Response

7.4.2.1 Operator Training

The training received by the operators was generally similar and appears to have met the requirements of the operator licensing process. The operators were examined on emergency procedures both with regard to the general content of the procedures and the required immediate actions. Table 12 compares the various facets of the operator training of the three plants.

7.4.2.2 SGT Rupture Emergency Procedures

Style, detail, content, and format of emergency procedures vary considerably among the utilities. Recently, Westinghouse conducted a review of emergency procedures, and the Westinghouse Owners Group was provided with detailed recommendations regarding format and content of the SGT rupture procedures. Presently, NRC is reviewing the Westinghouse recommendations, and the utilities are in the process of making major revisions in a number of their emergency procedures including those for SGT rupture. Also, the current procedures have not totally incorporated the new NRC requirements for RCP trip, subcooling conditions, and natural circulation. The staff's requirements have been temporarily incorporated by procedural change cover sheets and/or standing operation staff orders pending the resolution of the concerns of NRC and the Westinghouse Owners Group. Therefore, it would be untimely to make a procedure comparison of the utilities until they have incorporated the revised operator guidance and accomplished the recommended changes to the procedures. The scheduled date for the completion of the procedural revisions, by the utilities, was December 31, 1979.

7.4.2.3 Operator Actions

Table 13 shows a comparison of the various operator actions and times during the three SGT rupture events.

Table 12

Operator Training

Item	Point Beach	Surry	Prairie Island
Formal class	Initial training and requalification program	Several days of classroom instruction	Initial training and requalification program
Plant-specific simulator	Use of other plant simulators with modified site-specific procedures	Use of Surry plant simulator and emergency procedure	Use of other plant simulators with modified site-specific procedures
Other	On-shift discussion required	On-shift discussion of emergency procedures not required	On-shift discussion of emergency procedures not required
Frequency	Annual simulator training starting in 1980	Classroom and simulator training at least annually	Classroom and simulator training at least annually; annual oral exams on emergency procedures

The first indication of the SGT rupture at Point Beach and Prairie Island Unit 1 was the air ejector discharge radiation monitor alarm. From the description of the event provided to the staff by the Virginia Electric Power Co. (VEPCO), the first indication of the Surry Unit 2 SGT rupture was a decrease in pressurizer pressure and level. The plant operators that were in the control room at the time have stated that the air ejector discharge high radiation alarm signal occurred at about the same time.

The Point Beach and Prairie Island Unit 1 operators did not immediately diagnose the cause of the air ejector discharge high radiation alarm signal and waited until the pressurizer level and pressure showed significant decreases. At Prairie Island, the indicated pressurizer level decreased off scale (low) before automatic reactor trip on low pressure. A manual reactor trip was not initiated, and the reactor was at 90% power for about 37 s without indication of any pressurizer inventory.

The Point Beach and Prairie Island Unit 1 radiation monitors did not respond properly after measuring the high radiation, and this probably confused the operators. The Surry Unit 2 plant operators recognized the air ejector discharge high radiation alarm signal, but the control rod movements taking place at the time led the operators to think the concurrent L_p and P_p drops were not due to the SGT rupture that had taken place.

Table 13

Operator Response

Item	Point Beach	Surry	Prairie Island
First indication of SGT rupture	Air ejector high radiation alarm	Maximum charging flow alarm and L_p drop	Air ejector high radiation alarm
Operator recognition	After L_p and P_p drop	After L_p and P_p drop and after manipulating control rods	After L_p and P_p drop
Affected SG	"B"	"A"	"A"
Sequence of operator actions:*			
Started 2d charging pump	2 min	5 min	9 min
Started 3rd charging pump	19 min†	NA	9½ min
Isolated reactor letdown	8 min	5 min	?
Initiated load reduction	30 min	M-7 min	A-6 min**
Rate of load reduction	5%/min	10%/min	10% (total)
Type of scram	Manual	Manual	Automatic
Time of scram	47 min	10 min	10 min, 9 s
Pressure at time of scram	?	≈1950 psig	1900 psig
Low-pressure scram setpoint	1865 psig	1860 psig	1900 psig
Type of SIS	None	Manual	Automatic
Time of SIS	NA	11 min	10 min, 14 s
Pressure at time of SIS	NA	≈1800 psig	1815 psig
Low-pressure SIS setpoint	1715 psig	1700 psig	1815 psig
Peak pressure following SIS	NA	2100 psig	2000 psig
Time of peak pressure	NA	≈16 min	≈22 min††
Method of terminating pressure rise	NA	Normal pressurizer spray and RCS cooldown	Manually operated one pressurizer PORV***

Table 13 (continued)

Item	Point Beach	Surry	Prairie Island
RCP trips	Manual; RCP "B"	Manual; RCP "B"	Manual; both RCPs
Time of RCP trip	66 min	19 min	12 min
RCP restarts	RCP "B"	none	RCP "B"
Time of RCP restarts	1 h, 40 min	NA	7 h
Time when affected SG was isolated (MSIV shut)	48 min	17 min	27 min
Time when stop feeding affected SG	58 min	17 min	?
Stopped one SIP	NA	15 min	32 min
Questionable actions	Tripped RCP "B" Continued feed of SG "B" (10 min after MSIV closure) Length of time to depressurize RCS	Did not isolate "A" loop Length of time to depressurize RCS	7 h without forced RCS flow††† No manual trip when L_p off scale (low)

* Includes reactor conditions; times are from rupture.

† The 3d charging pump was out of service and was rapidly placed back in an operating condition, then started.

** The alarm log indicates that an overtemperature ΔT turbine runback was indicated earlier, but plant personnel state that this alarm did not actually initiate a runback.

†† At this time, the rate of RCS pressure rise was decreasing as pressure approached the HPSIP pump shutoff head (2200 psig).

*** The PORV was used to reduce RCS pressure once it had essentially stabilized at about 2000 psig.

††† The licensee did not have RCP restart procedures at the time; therefore, the staff required vendor analyses before allowing the licensee to restart the RCPs.

The second charging pump was started very soon after the rupture at Point Beach Unit 1 and Surry Unit 2, but relatively late during the Prairie Island Unit 1 event since the level did not start dropping significantly until about 5 min after the initial radiation alarm. However, as shown in Table 6, even if the second and third charging pumps had been started immediately after the rupture, the flow rate was such that automatic scram could not be avoided.

Plant load reduction was initiated earliest during the Surry Unit 2 event, although power had decreased to only 70% when the plant was tripped. However, the Point Beach Unit 1 operators waited 30 min before initiating the load reduction, but there was less need for prompt operator action due to the slow pressurizer pressure and level decrease. The plant operators at Prairie Island Unit 1 reduced plant load by only 10%; however, it is not apparent that a larger load reduction would have significantly altered the plant response once the scram occurred on low pressure.

The plant was manually tripped during the Surry SGT rupture event since the system pressure was approaching the low pressure scram setpoint. This action was prudent and preferable to waiting for the automatic scram. At the Prairie Island Unit 1 event, the automatic scram could not be avoided.

The operators manually initiated SI during the Surry Unit 2 event, seeing that system pressure was still dropping after the scram and SI was imminent. Again, this action was prudent. The leak rate during the Prairie Island Unit 1 event was such that automatic SI could not be avoided.

The use of the normal pressurizer spray, normal cooldown, and the securing of one SIP resulted in the control of RCS repressurization following SI actuation at Surry Unit 2. However, it appears that charging flow should have been maintained through the normal SI flow path, with one charging pump secured. The combination of stopping one charging pump and initiating flow through the normal charging flow path resulted in so low a flow into the RCS that pressurizer level again dropped out of the indicating range. The staff could not determine pressurizer level. Also, it could not be determined whether pressurizer level could have been maintained within the indicating range and whether RCS pressure could have been reduced if the SI flow path had been retained, with one charging pump.

The use of the pressurizer PORV to reduce the RCS pressure following SI actuation at the Prairie Island Unit 1 event was probably prudent. Since the operators' guidance at that time was to keep all HPSIPs operating for at least 20 min following low-pressure SI actuation, the reduction in plant pressure with both HPSIPs running could only be done by using the PORV.

As stated in Section 7.1.1, the Point Beach Unit 1 operators tripped RCP "B," probably to aid the RCS cooldown, but this is judged to have had only a marginal effect on the attainable cooldown rate. Tripping RCP "B" did result in a loss of spray from that pump. The pump was later restarted.

The Surry Unit 2 operators tripped RCP "B," but this did not result in a reduction in pressurizer spray since the pickups are downstream of RCPs "A" and "C."

The Prairie Island Unit 1 operators tripped both RCPs 2 min after the low-pressure SI actuation, as was required by NRC at that time. Pump "B" was not restarted for 7 h.

In all three events, the isolation of the affected SG took longer than the 10 min assumed in the FSAR. However, the leak rates were all less than the FSAR leak rates. Also, the RCS activity levels were all below those assumed in the FSAR. Therefore, the damaged SG was probably not as easily determined. The Surry Unit 2 operators identified the broken SG earliest of all three licensees, in 17 min. It is not apparent why the Prairie Island Unit 1 operators took 27 minutes to determine and then isolate the damaged SG, especially considering the leak rate.

The difficulties, already identified, associated with the Point Beach Unit 1 SG "B" level may have been due, in part, to the extra 10 min of feedwater after the MSIV had been shut.

The operator actions during the three events that may have completed the cool-down and recovery operations are listed. It should be noted that these actions are not thought to be significant and, in general, the operators responded to the SGT ruptures with prudent actions and successfully avoided significant releases to the environment.

7.4.3 Radiological Consequences

Table 14 shows a comparison of the available information regarding the consequences of the three SGT rupture events. As shown in Table 14, the primary coolant I-131 equivalent concentration at Prairie Island was 25 mCi/g.

By comparison, a primary coolant concentration of 0.73 μCi/g was measured at the time of the Point Beach Unit 1 tube rupture. This increase in primary coolant concentration would have resulted in a 30-fold increase of the offsite doses. This direct relationship between SGT rupture accident doses and primary coolant activity has been used to derive limiting primary coolant concentrations that, in the absence of additional accident-caused fuel failures, will assure that the resulting doses are a small fraction of the dose guidelines of the reactor siting criteria of 10 CFR Part 100. These standard technical specifications for primary coolant activity have been adopted by all but 10 PWR licensees.

The various radioactive release paths are shown for the Point Beach and Prairie Island Unit 1 events. The release paths during the Surry event are not known.

The licensee's estimates of the total activity released during the Point Beach and Prairie Island Unit 1 events show a significant difference. The staff's estimate of the total quantity released during the Prairie Island Unit 1 event is about 210 μCi I-131 equivalent. Staff assessment of the total dose to the thyroid is larger than the licensee's by two orders of magnitude, but is still well below both 10 CFR 20 and 10 CFR 100 requirements.

Table 14

Radiological Consequences

Item	Point Beach	Surry	Prairie Island
Primary coolant activity (I-131 equivalent)	0.73 µCi/g	NA	25 nCi/g
Release paths	TD AFP Air ejector discharge Blowdown tank vent Steam system leaks Atmospheric blowoff tank vent Condensate storage tank vent	Air ejector discharge* Blowdown vents* Steam system leaks* Condensate storage tank Containment leakage* Liquid processing system*	TD AFP Air ejector discharge ADV operation Gland exhaust Liquid processing systems Containment leakage
Total released to atmosphere:			
Licensee estimate	3055 Ci†	NA	Xe-133: 30 µCi I-131: 1 µCi
Staff calculation			I-131: 210 µCi
Thyroid dose (I-131 equivalent):	NA	NA	
Licensee estimate			23 nrem
Staff calculation			4.3 µrem

*Specifics are unavailable; therefore, these may have been the release pathways.

†Noble gases and iodine isotopes.

7.4.4 Summaries

Table 15 shows a comparison of the staff summaries for each event. Sufficient information was not available for review of the Point Beach Unit 1 and Surry Unit 2 events.

There were no traces of system parameters available for the Point Beach Unit 1 event, and the Surry Unit 2 traces were quite poor. Also, the Surry Unit 2 computer log was initially used by the staff in attempting to determine an event sequence, but the staff was later informed that this, too, was inaccurate.

The three events were caused by different mechanisms. The Point Beach Unit 1 SGT rupture was caused by wastage and caustic stress corrosion of an outer row tube. The Surry Unit 2 event was caused by stress corrosion cracking of a Row 1 tube in the U-bend region. (This was also the cause of the SGT rupture at Doel Unit 2, and perhaps at Cadarache, as described in Appendix H.) The Prairie Island Unit 1 SGT rupture was caused by mechanical wear. Apparently some equipment was left in the SG after a previous sludge lancing operation.

The various problems with the radiation monitoring equipment are next indicated. Point Beach Unit 1 had difficulties with both the air ejector discharge and SG blowdown monitors, and apparently Surry Unit 2 had difficulties with the blowdown monitor. The air ejector discharge radiation monitor at Prairie Island Unit 1 gave intermittent alarm signals. Also, the Prairie Island Unit 1 blowdown monitor radiation alarm never actuated.

In all three events, there were probably no significant offsite doses, and this is to the credit of the operators. As indicated in Section 7.3.3 on Prairie Island Unit 1, there was the potential for significantly more release had the proper actions not been taken.

The other items shown on Table 15 have been discussed in previous comparisons, and are presented here since they are considered important summaries.

Table 15

Summaries

Item	Point Beach	Surry	Prairie Island
Availability of sufficient information	Unavailable	Unavailable	Available
Cause of ruptured tube	Wastage and stress corrosion cracking	Stress corrosion cracking (Row 1 tube)	Mechanical damage
Plant control following rupture	Slow decrease in pressure and level allowed an almost normal shutdown	More rapid drop in pressure and level required a manual scram and manual SI actuation	Very rapid drop in pressure and level resulted in automatic scram and SI actuation
Radiation monitoring equipment:			
Air ejector discharge	Did not work properly	Worked properly	May not have worked properly
Blowdown monitor	Did not work properly	Did not work properly	Alarm never actuated
Other	Slow RCS depressurization and sustained feedwater flow to damaged SG resulted in excessive SG level	Slow RCS depressurization during cooldown	Slow RCS depressurization during cooldown
	RCP in damaged loop tripped and had to be restarted	RCP in undamaged loop tripped to aid in cooldown	Both RCPs tripped as per NRC requirements
	No problem with RCS dilution	Operator isolated damaged SG early	No problem with RCS dilution
	Release to atmosphere via TD AFP	Rapid RCS repressurization and level restoration after SI actuation	Release to atmosphere via ADV and TD AFP
	Probably no significant offsite doses	Operators secured 1 SIP and P_p and L_p decreased; P_p L_p out of indicating range for about 20 min	No significant offsite doses
		No problem with RCS dilution	
		Probably no significant offsite doses	

APPENDIX A

FSAR SGT RUPTURE ANALYSIS

This appendix gives a general, FSAR-type analysis of an SGT rupture accident. Although the FSAR analyses of the three licensees differed, all were similar to the description given in this appendix.

The FSAR presented a discussion and evaluation of a number of SGT rupture cases, all assuming a complete severance of a single SGT adjacent to the tube sheet and a complete loop at the time SI is automatically intitiated.

The analyses predict the following general sequence.

(1) Low P_p and low L_p alarms are actuated and, prior to unit trip, charging pump flow increases in an attempt to maintain pressurizer level. The damaged SG feed flow is automatically reduced because of the rising level from the SGT break flow. Before unit trip, the damaged SG level would be constant with a feed-flow/steam-flow mismatch.

(2) Loss of RCS inventory results in dropping values of P_p and L_p, and eventually a reactor trip signal is generated on low P_p. Automatic unit cooldown following reactor trip leads to a rapid drop in L_p, and the SI signal, initiated by coincident low P_p and low L_p, follows soon after the reactor trip. The SI signal automatically terminates normal feedwater supply and initiates AFW flow.

(3) The SG blowdown liquid monitor and the air ejector radiation monitor alarms are actuated almost immediately after the rupture indicating the passage of reactor coolant into the secondary system. (On Surry Unit 2, a signal is generated that automatically diverts the air ejector exhaust from the condenser to the containment, thereby terminating any direct atmospheric release.)

(4) The unit trip automatically shuts off steam supply to the turbine generator and, if OSP remains available, the condenser bypass valves automatically open to reduce RCS temperature to the no-load value. If OSP is lost, which is assumed in the analysis, the condenser bypass valves shut to protect the condenser from overpressure, and pressure in all SGs rapidly rises and steam is discharged directly to the atmosphere through the SG SVs and/or the ADVs.

(5) Following the reactor and turbine trip, the continued action of the AFW system and borated SI flow (from the RWST) provides a heat sink that eventually absorbs decay heat. Thus, steam bypass to the condenser or, in the case of loss of OSP, steam relief to the atmosphere is discontinued on a time scale that is dependent on the exact amount of emergency equipment (SIPs and AFPs) operating.

(6) SI flow results in increasing pressurizer water level. (The time after trip when the operator can see returning level in the pressurizer is also dependent upon the amount of operating auxiliary equipment.)

The operator's intervention during the course of events is necessary, and this action is assumed to be timely enough that the break flow through the damaged SGT is terminated before water level in the affected SG rises to the main steam pipe. The following operator actions are assumed:

(1) Before the faulty SG is identified, AFW flow is regulated to all SGs to maintain the minimum water level reached as no-load temperature and pressure are established.

(2) If OSP is available, the operator verifies that condenser steam dump maintains the no-load T_{AVE} and transfers steam dump to steam header pressure control.

(3) As water level returns in the pressurizer, all SIPs except one are stopped to minimize break flow to the secondary system.

(4) The damaged SG is identified by rising water level. (For Surry Unit 2, the RCP in the associated loop is stopped, and the loop isolation valves are closed.) As soon as the affected SG pressure is reduced below 1100 psig, the MSIV is closed. This completes isolation of the faulty SG.

(5) AFW flow to the faulty SG is stopped.

(6) If the affected SG has not been discovered by the time level returns in the pressurizer, it is then identified by sampling the SG secondary side.

(7) The steam header pressure is reduced to 850 psig with condenser steam dump if OSP is available. This cools the entire system below 1100 psig, at which time the MSIV on the affected steam line can be closed, steam dump being continued from the other SGs.

(8) If OSP is not available, atmospheric steam dump from the unaffected SGs is used to establish 850 psig. At the same time, the RCS pressure is decreased to 1000 psig using pressurizer relief valves and spray. These actions automatically reduce the pressure in the faulty SG below 1100 psig, and steam line isolation can then be achieved.

The FSAR states that the RCS is then cooled to the cold shutdown condition, using whatever systems are necessary. (The Surry FSAR gives an estimate of the time necessary to fill the faulty SG and states that about 4 min is required for the water inventory to increase to the low level top on the damaged SG after reactor and turbine trip.) The operator is required to terminate AFW flow to the damaged SG. From this point, another 30 min would be required for the water level to rise into the main steam pipes with all three SIPs operating. Therefore, the operator must terminate SGT break flow before flooding the damaged SG into the steam lines. This can be accomplished by taking the actions already described.

Table A.1 lists the results of the four cases described in the Surry FSAR. In each case, the values of P_p and L_p dropped rapidly. The value of P_p dropped to the minimum value show, then recovered gradually to the final P_p shown in the table. The value of L_p dropped to 0 ft^3 in 400 s in all cases and recovered to the final L_p value shown. In all four cases, no operator action was assumed.

Table A.1 Results of Surry FSAR analysis

Parameter	Case 1 (2 SIPs; 100% AFW)	Case 2 (2 SIPs; 50% AFW)	Case 3 (1 SIP; 100% AFW)	Case 4 (1 SIP; 50% AFW)
Initial depressurization rate (psi/s)	1.63	1.63	1.63	2.10
RCS cooldown rate, initial (°F/h)	110	100	80	30
Minimum RCS pressure (psig)	1600	1600	1250	1600
Time when pressurizer empties (s)	400*	400*	400†	400*
L_p at 30 min (ft^3)	100	200	0	70
Final L_p (ft^3)	100	200	0	70
Final RCS pressure (psig)	1750	1925	1250	1650
RCS temperature at 30 min (°F)	500	540	500	555
End of steam discharge (s, after trip)	104	396	100	744
Mass of steam discharge (10^3 lbm)	13.8	19.8	14.3	20.3

*Analysis shows the pressurizer empties at about 400 s, but then immediately starts refilling due to the SIS.
†Analysis shows the pressurizer empties at about 400 s, and doesn't refill.

The FSAR also shows that at t = 30 min for Case 4, 10% of the RCS inventory has been leaked to the damaged SG secondary.

The FSAR-predicted doses to an individual standing on the site boundary for Case 4 are 280 mrem to the thyroid and 300 mrem to the whole body resulting from the steam released through the damaged SG SVs.

APPENDIX B

DETAILED EVENT SEQUENCES

1. POINT BEACH UNIT 1

Initial Conditions

Plant was operating at full power; previous RCS leak rate calculations showed acceptable values.

Time	Event
2312	Unit 1 air ejector discharge gas monitor R15 registered high; then dropped low.
2313	Since on the previous shift charging pump "A" had been isolated due to seal leakage and the auxiliary building stack monitor R14 indicated an increase, the initial investigation was directed toward a possible leak in the auxiliary building.
	High limit alarm for unit 1 charging pump speed control came on. The CRO checked the running charging pump "B" controller position and then observed pressurizer level slowly dropping.
2314	Charging pump "C" was started by the CRO.
2314-2331	During this period, pressurizer level was falling slowly and the CRO was manually increasing charging pump speed accordingly. All radiation monitors were checked for assistance in locating the leak. A continuing rise on R14 still appeared to indicate a leak in the auxiliary building. Pressurizer level dropped approximately 6%.
2317	Auxiliary building exhaust stack R14 monitor alarm actuated.
2320	The operator manually secured RCS letdown. Two supervisors went to the primary auxiliary building to assist in locating the suspected leak.
2331	Charging pump "A" was unisolated and placed in service.
2331-2336	The CRO increased the third charging pump speed to its maximum. The VCT commenced a gradual reduction in level.
2336	An operating supervisor detected, after a detailed examination, a small perturbation in the SG "B" feed flow. The leak rate at this time was estimated to be 125 gal/min.
2338	A portable monitor, used to check activity at the air ejector discharge in-line filter located approximately 2 ft from R15, showed a 1 R/h field; a similar check at blowdown sample cooler "B" showed 50 mR/h.

2340 The conclusion was made by the operating staff on duty that the leak was primary to secondary into SG "B." Blowdown on both SGs was secured remotely at the control board by the CRO.

2342 The unit was placed on a ramp from 500 to 150 MWe at a rate of 5%/min.

2344 The alarm on blowdown sample monitor R19 actuated and closed sample line isolation valves as the supervisor was manipulating the sample line valves.

2359 The reactor was tripped manually by the operator at 25% power level. No activation of ADVs or SVs was required.

0000 Main steam stop valve "B" was closed.

0003 Reduction of primary system pressure was started and cooldown was begun using SG "A" condenser steam dump.

0006 SI was blocked at 1790 psig.

0007 A sampling program was begun by health physics personnel.

0010 All feed to SG "B" was secured.

0012 Charging pump suction was taken directly from the RWST.

0013 To maintain adequate pressurizer level, SIPs "A" and "B" were operated briefly and periodically as required during cooldown.

0018 The SI accumulators were isolated at 1240 psig primary system pressure; RCP "B" was secured.

0025 Charging pump "A" was secured.

0031 Charging pump "C" was secured.

0049 Charging pump "C" was restarted.

0050 RCP "B" was restarted to assist cooling of SG "B".

0052 Charging pump "A" was restarted.

0100 Summary of conditions: RCS pressure was 1000 psig at 430°F; SG "A" pressure was 300 psig, and SG "B" pressure was 920 psig. Operators changed the valve lineup of the air ejector drains to direct condensate to the retention pond rather than to the atmospheric blowoff tank and the service water system.

0122-0142 The SG "B" main steam stop 3-in. bypass valve opened to bleed steam to condenser and prevent any possibility of residual heat in SG metal from causing further rise in SG pressure and activation of SVs.

0135 Charging pump "B" was secured.

0217 The RHR operation was begun.

0301 Charging pump "B" was restarted.

0515 The loop "B" main steam line spring-loaded pipe hangers were blocked to prevent possible pipe or structural damage in the unlikely event of the SG filling to the main steam stop valve.

0635 The RCS pressure was 320 psig; primary system temperature was 182°F; boron concentration was 1235 ppm.

2. SURRY UNIT 2

Initial Conditions

The plant was operating at full power, and, according to the CRO Log, the previous RCS leak rate was satisfactory (1.40 gal/min total; 0.60 gal/min unidentified).

Excore nuclear instrumentation calibration was in progress. The operator had just driven a bank of control rods in eight steps to provide a $-5\Delta\phi$, and as a result T_{AVE} decreased 3°F. After about 5 min, T_{AVE} continued to decrease (about 1°F in that interval). The CRO observed a drop in L_p, which was assumed to be due to the drop in T_{AVE}.

Time	Event
1336	The maximum charging flow alarm and the pressurizer pressure were seen to be dropping. The CRO withdrew previously inserted control rod bank "D" 18 steps, but T_{AVE} was not observed to respond.
1337	Another operator noted a high alarm signal on the air ejector radiation monitor and rapidly decreasing values of P_p and L_p.
1338	Four low P_p alarms and a wide range RCS low-pressure alarm sounded (all alarms occurred at 2140 psig).
1340	The interval of automatic VCT makeup indicated the VCT level was (at this time) dropping at approximately 100 gal/min. Three low L_p alarms at 17.2% (first alarm at 18%) were followed by another low L_p alarm at 14.7%.
1341	Automatic makeup to the VCT was again automatically initiated, indicating a decreasing level. The value of L_p dropped below about 14.4%, automatically shutting off all pressurizer heaters. The RCS letdown was secured. (Operator manually shut the motor-operated valve, and two air-operated valves were automatically shut when L_p dropped below 14.4%.) A second charging pump was started.*

*Alarm log shows this event at 1347, but other indications suggest 1341.

1343 Low level and pressure alarms in the VCT indicated a continuing drop in the VCT inventory. 'Charging pump suction automatically switched to the RWST. The CRO initiated emergency boration by lining up the discharge of the boric acid transfer pumps directly into the charging pump suction and commenced load reduction at 10%/min.

1345 A low-low pressurizer level (<5%) SI partial trip occurred; SI P_p block (return of alarm) indicated P_p was about 2000 psig.

1346 Manual turbine and accompanying automatic reactor tripped. (Reactor and turbine power at time of trip were about 70%, and T_{AVE} was about 562°F, a reduction from full load value of about 566°F.)

1347 The TD AFPs "A" and "B" started on low SG level; VCT level returned due to continued automatic makeup, with the charging pump drawing from the RWST and the boric acid transfer pump. Manual SI was initiated. (Recorders showed P_p at about 1800 psig and L_p off scale low.) All main feedwater pumps tripped automatically at initiation of SI.

1349-1350 SG "A," "B," and "C" low-low level alarms actuated.

1351-1352 SIS was manually reset. (The 5-min time delay was satisfied.) Both low head SIPs and SIP "A" were stopped. High-pressure SI flow path (through BIT) was secured and flow from one SIP through normal charging flow path was initiated. Values of P_p and L_p peaked at about 2100 psig and 17%, respectively.

1353-1354 The RCS cooldown was temporarily slowed, feedwater from all three SGs was isolated, and the SGT rupture was determined to be in SG "A"; SG "A" was isolated by shutting its MSIV and feedwater MOVs; RCS cooldown was recommended. Both TD AFPs were manually tripped, and normal feedwater flow from one of the main feedwater pumps was initiated.

1355 The RCP "B" was stopped.

1357 Charging pump "A" was restarted and flow back through the high-pressure SI flow path (through BIT) was initiated. (Recorder showed P_p at about 1915 psig, and L_p was off scale low.)

Final Conditions

The plant was cooled to <500°F and depressurized to <1000 psig as required by emergency procedures; SG "A" pressure and level were continually monitored; the plant was cooled to cold shutdown for SG maintenance.

3. PRAIRIE ISLAND UNIT 1

Initial Conditions

The plant was operating at its full power. Prior to the accident, no leakage between the RCS and secondary system was detected.

Time	Event
1414	A high radiation alarm sounded on 1R15 (air ejector discharge gaseous radiation monitor).
1420	Overtemperature ΔT turbine runback occurred due to decreasing pressure.
1421	Low pressurizer pressure alarm occurred (<2139.9 psig).
1421 (approx.)	Load reduction was begun.
1422	Low pressurizer level alarm occurred (<18.3%).
1423	The second charging pump (No. 11) was started.
1423	Pressurizer level indication was off scale - low.
1424 (approx.)	The third charging pump (No. 13) was started.
1424:09	Reactor was automatically tripped because of low pressurizer pressure.
1424:14	Because of low pressurizer pressure (<1815 psig), SI occurred.
1424:33	The RCS water inventory was at a minimum; RCS pressure began increasing.
1426	The RCP No. 11 stopped.
1427	The RCP No. 12 stopped.
1432:29	The SG No. 11 level increased above the low-low level setpoint (13%) on the narrow range after having gone off scale low after the trip. (It is normal for SG level to go off scale low on a trip; recovery in this case was much more rapid than usual.)
1438	The SIS was reset.
1441	Loop "B" MSIV closed during high steam flow. Loop "B" MSIV was immediately opened by the operator, and "A" MSIV was closed.
1456	Pressurizer level returned on scale; SIP No. 12 was stopped.
1456-1457	Depressurization of the RCS using the pressurizer PORV was begun. (The valve was cycled 6 to 8 times to reduce pressure to the required value.)

1502 The pressurizer level reached the high level setpoint (>55%).

1506 The SIP No. 11 stopped.

1507 Pressurizer relief tank rupture disk opened.

1515 The RCS pressure at 910 psig (same as SG No. 11 pressure) leakage flow apparently stopped.

1550 Normal cooldown was started.

0640 The RHR system was placed in service to continue cooldown to cold shutdown.

1300 The RCS reached cold shutdown.

APPENDIX C

DESCRIPTION OF SGT FAILURE MECHANISMS, OPERATING HISTORIES, AND REMEDIAL ACTIONS

1. DESCRIPTION OF SGT FAILURE MECHANISMS

1.1 Caustic Stress Corrosion and Wastage

Inconel-600 tubing is typical of that found in most operating SGs. Intergranular stress corrosion cracking and localized tube wall thinning (wastage) are the major types of degradation that affect the exterior surface of the tubing in recirculating type SGs designed by both Westinghouse and Combustion Engineering. "Pitting" (that is, relatively deep, small volume wastage of the exterior surface of SG tubing) has also been experienced.

Wastage has occurred when a coordinated phosphate treatment of the secondary coolant was used and is attributed to a local concentration of residual acidic phosphates. In some cases these acidic phosphates have not been completely removed after a changeover from a phosphate treatment to an AVT of the secondary coolant water. (This chemistry control is called AVT because the chemicals injected into the secondary water eventually volatilize and escape with steam.) Approximately a dozen domestic plants have experienced some degree of wastage while operating with phosphate water treatment. Since the establishment of AVT chemistry control, both the evidence and the extent of wastage have diminished and no further substantial tube degradation due to this mechanism is expected to occur. Caustic stress corrosion cracking is caused mainly by either the formation of caustic compounds in the secondary coolant (that is, from hydrolysis of trisodium phosphate) or by caustic-forming impurities carried into the SG by the feedwater.

The principal cause of serious corrosion damage from either wastage or caustic stress corrosion cracking is the local concentration of aggressive chemicals within the secondary side of SGs. The major source of these impurities is inleakage of condenser cooling water. Because of this, the boundary between the secondary coolant system and the condenser cooling system is of significance. The concentration of these impurities is affected by the thermal and mechanical design parameters of SGs, by accumulations of chemicals and corrosion products within the SGs as plants age, and by the normal and transient variations in water and air environments to which SG internals are exposed. Both types of corrosion generally occur when regions of restricted water flow and high heat flux tube surfaces cause nonvolatile impurities to concentrate or phosphates to precipitate (hideout). These high concentrations may occur at crevices between the tubing and the tube support plates or the tube sheet, and in areas where sludge deposits have built up on the tube sheet or tube support plates.

1.2 Denting at Tube/Tube Support Plate Intersections

In December 1975, the NRC was informed by Westinghouse that several plants designed by them had experienced SGT deformation in the form of a reduction in tube diameter. This reduction in tube diameter was later termed "denting."

Later laboratory reports of dented tubes indicated that the annulus between tubes and support plates was filled with hardened corrosion products that continue to form by the corrosion of the support plates and exert sufficient forces to "dent" the tubes diametrically. Severe buildup of corrosion products has caused cracking of the tube support plate ligaments between the tube holes and the water circulation flow holes. The phenomenon of denting in Westinghouse plants has been attributed to acid chloride salts that concentrate in the annulus between the tubes and the tube support plates. The first incidence of denting occurred shortly after SG secondary water chemistry control was switched from phosphate treatment to an AVT. Contamination of the secondary coolant by inleakage of condenser cooling water was believed to have caused a catalytic reaction with residual phosphates.

The simultaneous presence of residual phosphate in the tube/tube support plate annulus and chloride in the condenser cooling water caused accelerated corrosion of carbon steel support plates present in most plants. The corrosion product from the carbon steel support plate occupies approximately twice the volume of the material corroded. The continuing corrosion product exerts sufficient force to dent the tube and/or crack the tube support plate ligaments between the tube holes and the water circulation flow holes, and these dented tubes become subject to higher strains.

Because of tube denting, tubes at tube/tube support plate interfaces have developed small stress corrosion cracks in the longitudinal direction of the tube. These small cracks are masked by the support plates. During normal operation, small leaks through these cracks have occurred in plants where severe tube denting has occurred. Recent denting events have occurred at plants using AVT exclusively.

1.3 Stress Corrosion Cracking in U-Bends

Along the chord of the innermost rows of tubes in Westinghouse-designed SGs, there is a row of rectangular flow slots in the tube support plate. These slots are approximately 16 in. long by 2-3/4 in. wide and are spaced about 20 in. center to center. Because of the pressure built up in the tube support plate due to the denting phenomenon, the flow slots in the tube support plates have been observed to deform (the "hourglassing" effect); that is, the central portion of the parallel flow slot walls has moved closer, so that some flow slots become narrower in the center than at the ends. Because the initial parallel slot walls have moved closer, the tube support plate material supporting the tubes nearest this central portion of these flow slots has also moved inward, which consequently forces an inward displacement of the legs of the tubes at these locations. When this inward movement of the legs of the tubes has occurred at the uppermost support plate, it has been shown to cause an increase in the hoop strain at the tube U-bend apex. This additional increase in strain at the apex of the U-bend greatly enhances susceptibility to stress corrosion cracking at the top of the U-bend for Inconel-600 alloy tubin exposed to PWR reactor coolant.

2. POINT BEACH UNIT 1 EVENT

2.1 Nature of the SGT Failure

On February 26, 1975, at approximately 11:00 p.m., an SGT failed in the Point Beach Unit 1 SG "B" while the plant was operating at full power. The failure was progressive over an interval of approximately 48 min. The first indication of failure was a spike on the air ejector monitor and, subsequently, at about 11:12 p.m., on the blowdown monitor. This was followed by manually increasing charging flow. A charging flow of 125 gal/min was able to maintain reactor pressurizer water level. This was estimated to be the leakage rate of the ruptured tube.

2.2 SG Operating History

Point Beach Unit 1 began commercial operation on December 21, 1970. The unit was operated with phosphate secondary water chemistry control through Fall 1974 when it was converted to AVT. During this period a substantial amount of sludge deposits accumulated on the tube sheet surface. The changeover to AVT at this reactor was accomplished without an intermediate sludge lancing so that the sludge deposits remained essentially in-situ during the first few months of AVT operation until the first sludge lancing in January 1975. Some of the sodium phosphate trapped in the sludge may have been converted to sodium hydroxide during that period and caused stress corrosion to develop in the same areas where wastage had previously occurred. The licensee's report to NRC on June 26, 1975, stated that the free caustic had been detected in the SGs of this unit during that period.

Prior to the February 26, 1975, tube leak, approximately 3.2% of the tubes in SG "B" had been plugged. These tubes were plugged mainly as a result of the wastage type of degradation described in Section 1.1 of this appendix.

2.3 Remedial Actions/Subsequent Experience

The licensee concluded that tube degradation, and thus tube rupture, was caused primarily by wastage-type corrosion and plugged all tubes having more than 30% eddy current indications. Secondary water chemistry control had already been converted from phosphate to AVT, and sludge lancing had been conducted in January 1975 to alleviate further wastage and caustic stress corrosion cracking problems. Although recent operating experience at Point Beach Unit 1 indicates that the wastage and caustic stress corrosion mechanism that led to the February 26, 1975, tube failure above the tubesheet has been largely arrested, corrosion damage to tubes within the thickness of the tube-sheet has recently been occurring at a high rate due to the "deep crevice cracking" phenomenon that is a phenomenon affecting early generation SGs in which the tubes were not fully expanded in the tubesheet. This "deep crevice cracking" is a form of caustic stress corrosion cracking that can affect SGs that have been converted from phosphate to AVT, such as Point Beach Unit 1, or have operated exclusively on AVT secondary water chemistry. Relatively small leaks (<1.5 gal/min) due to this phenomenon occurred on September 20, 1978; March 12, 1979; and August 5, 1979. Because of the constraint provided by the tubesheet, the deep crevice cracks are not considered to be a significant safety concern during normal operation or postulated accident conditions.

However, this form of degradation has had a significant impact on plant availability, and, unless arrested, may eventually force a derating in power or a SG replacement at Point Beach Unit 1.

3. SURRY UNIT 2 EVENT

3.1 Nature of the SGT Rupture

On September 15, 1976, during normal operation, Surry Unit 2 developed a primary-to-secondary system SG leak of approximately 80 gal/min. This leak resulted from an axial crack about 4-1/4 in. in length on the primary side of the tube surface in the U-bend apex of one of the SGTs in the first row. It was determined to have been caused by the stress corrosion phenomenon described in Section 1.3 of this appendix.

3.2 SG Operating History

Surry Unit 2 began commercial operation on May 1, 1973, and, like almost all units with U-tube SG design, employed a sodium phosphate secondary water chemstry treatment. This treatment was designed to remove precipitated or suspended solids by blowdown and was successful as a scale inhibitor. Primarily because of wastage and caustic stress corrosion cracking problems encountered with the phosphate treatment, most PWRs employing SGs with a U-tube design, Surry included, converted to AVT chemistry control.

In 1975, radial formation of SGTs, or the so-called denting phenomenon described in Section 1.2 of this appendix, occurred in several PWR facilities after 3 to 14 months' operation following conversion to AVT secondary chemistry. Surry Unit 2 converted to AVT chemistry in February 1975, and denting and support plate cracking were first observed in May 1975.

3.3 Remedial Actions/Subsequent Experience

Operation of Surry Unit 2 and similarly degraded facilities at Surry Unit 1, Turkey Point Units 3 and 4, Indian Point Unit 2, and San Onofre Unit 1 have been closely monitored by NRC. Following the September 15, 1976, tube failure incident at Surry Unit 2, these six units implemented preventive plugging of the innermost row of tubes in each SG to avoid a recurrence of stress corrosion cracking at the apex of the small radius U-bends. In addition, augmented inservice inspection programs have been implemented at increased frequency (typically 6 months) and with expanded sample sizes to carefully monitor the rate of SGT degradation. Each inservice inspection has included eddy current inspections, tube gauging, and support plate examinations. The number and locations of the tubes to be gauged have been established using a finite element computer model for predicting the growth and deformation of the tube support plates. As a result of each inspection, tubes that were judged to be susceptible to stress corrosion cracking and that may begin to leak prior to the next inservice inspection were plugged.

For Surry Units 1 and 2 and Turkey Point Units 3 and 4 (the four most extensively degraded units) the potential for dent-related cracking (at U-bends and support plates) has necessitated the preventive plugging of 25% and 22% of the tubes in Surry Units 1 and 2, and 18% and 21% in Turkey Point Units 3 and 4, respectively. The frequent inspections and extensive preventive tube plugging have adversely affected the availability of these units. Continued degradation and attendant tube plugging would eventually require derating of the thermal output of these units (due to excessive loss of heat transfer surface area in the SGT). For these reasons, Surry Unit 2 is currently undergoing and Surry Unit 1 is planning replacement of the lower portions of the SGs (including new tube bundles); a similar replacement program is planned for the Turkey Point units. The repaired generators will incorporate several design changes that are expected to eliminate or greatly reduce the potential for the types of degradation observed so far, as described in Section 1.0 of this appendix.

4. PRAIRIE ISLAND UNIT 1 EVENT

4.1 Nature of the SGT Rupture

On October 2, 1979, Prairie Island Unit No. 1 experienced a primary-to-secondary system SGT leak of about 390 gal/min (licensee's estimate). The reactor was brought to a cold shutdown in a routine manner following the emergency procedures for such an event. Subsequent investigation discovered a foreign object near the ruptured tube, which was determined to be wearing against the tubes, leading to a significant reduction in wall thickness of three tubes and subsequent pressure burst failure of one of the three tubes.

4.2 SG Operating History

Prairie Island Unit 1 began commercial operation on December 16, 1973, and prior to the October 2, 1979, incident had been operated without signs of SG corrosion degradation or tube failures. The Prairie Island SGs are of the Westinghouse model 51 design. The most recent inservice inspection of SG "A" (where the leak occurred) prior to the October 2, 1979, incident was conducted in March 1977 during which time ECT was performed on 4.5% (exceeding the technical specification minimum requirement of 3%) of the SGTs. No pluggable tubes were found during this or in the previous four inservice inspections performed since the beginning of commercial operation. Sludge lancing to remove accumulated sludge deposits was performed as part of each inservice inspection and maintenance activity.

4.3 Remedial Actions

It was concluded on the basis of the postincident inspection that the rupture was caused by mechanical wear of the tubes against the steel coiled spring that eventually led to pressure burst. This was considered to be an isolated occurrence with no generic implications other than for the Quality Assurance Program.

In addition to the failed tube, and the adjacent tube with a 65% wall reduction, the remaining four tubes adjacent to the failed tube were also plugged. This action was taken to preclude additional ruptures in the event that the failed tube should break further and damage the adjacent tubes. The licensee has also agreed to inspect the condition of the ruptured tube during the next outage.

Lessons learned from this tube rupture incident are consistent with the laboratory burst test of degraded tubes in that the rupture size and the resultant leakage rate were dependent upon the size of thinned tube surface area prior to the burst. There is no evidence that the length of the opening extended outside the thinned down region. The opening is shown to be in a classical "fishmouth" shape. The fact that the tube with 65% wall reduction (Column 3, Row 1) did not rupture further substantiates the conservative nature of the present tube preventive plugging criteria.

APPENDIX D

BORON CONTROL SYSTEMS AND STAFF CALCULATIONS

1. BORON CONTROL SYSTEMS

1.1 Point Beach Unit 1

When the SIS is initiated, the Point Beach Unit 1 HPSIPs initially take a suction on the BATs. When the tank level decreases below the low-level setpoint the HPSIP suction switches automatically to the RWST. The VCT is the normal charging pump suction source, and it is kept pressurized with H_2 for RCS chemistry control. The VCT boron concentration is controlled by the mix and blend system. The system automatically or manually adds a makeup water at a predetermined boron concentration to the VCT and charging pump suction header. In the "automatic" mode of operation, the system adds makeup water at the same boron concentration as the water in the VCT.

In the "automatic" mode, a preset low-level signal from the VCT level controller opens various valves in the makeup water system and starts the makeup and boric acid transfer pumps. The flow controllers then blend the makeup stream according to the preset concentration. Makeup addition to the charging pump suction header causes the water level in the VCT to rise. At a preset high-level setpoint, the makeup is stopped, the valves return to their normal position, and the reactor makeup water and boric acid transfer pumps stop automatically if they were started automatically.

1.2 Prairie Island Unit 1

In the Prairie Island plant SIPs initially draw injection water from the BATs and only when this source of water is depleted are they aligned to draw injection water from the RWST. There are three BATs shared between two units, each containing 5000 gal. of boric acid solution having 20,000 ppm boron. The plant contains one RWST containing 275,000 gal. of 2100-ppm boric acid solution.

2. STAFF CALCULATIONS

2.1 General

This section shows that there was no criticality problem due to RCS dilution following the SGT rupture event at Prairie Island. There are two factors making the actual situation somewhat different from the one calculated:

(1) The staff's calculations assume an initial RCS boron concentration consistent with the operation of the SIS following the tube rupture. However, the Point Beach and Prairie Island SISs both initially take suction from the BAT, then switch to the RWST. In the actual event, automatic SIS operation never occurred. Therefore, the staff cannot assume the highly concentrated BAT contents were injected into the RCS. If not, then the RCS boron concentration just prior to dilution was below that assumed in the staff calculations. This effect makes the final RCS boron concentrations, after dilution, somewhat worse.

(2) The staff calculations assume that the secondary water inventory is completely returned to the RCS, via the ruptured tube, and is pure water. In addition, the Prairie Island SG is slightly larger than the Point Beach SG. These are highly conservative assumptions and make the final calculated RCS boron concentration significantly lower than actual.

2.2 Criticality Analysis of Cooldown and Dilution of PWR Primary System

This section contains an analysis of the reactivity effects due to cooldown and dilution (by inflow of secondary water) of a PWR primary system following an SGT. The scenario that would allow this deboration to occur is not described, and the extent of deboration to be expected in an SGT rupture accident has not been determined. Instead, the deboration event is assumed to occur at various initial conditions (that is, beginning of life (BOL), no xenon; BOL, equilibrium xenon; middle of life (MOL); and end of life (EOL)), and the degree of dilution is investigated parametrically. Boron concentrations, control rod worths, and reactivity coefficients were obtained from the Prairie Island FSAR and are, therefore, representative of first cycles cores.

To calculate reactivity states, a reactivity decrease of 7.5% $\Delta k/k$ was assumed as a result of reactor trip (full control rod insertion). The reactivity increase due to the power defect and control rod bite in going from full power (569°F) to hot standby (545°F) was obtained from the control rod reactivity requirements presented in the FSAR. A linear average between the BOL and EOL values was assumed for the MOL state. The additional reactivity increase due to further cooldown from hot standby to 68°F was obtained from the moderator temperature coefficient curve given in the FSAR. Values of BOL with control rods inserted were obtained by interpolation from the FSAR figure.

The total amount of boron in the core was assumed to be 3000 ppm. This results from a combination of SI boron and boron present at the specific time in the operating cycle (i.e., 1359 ppm at BOL (no xenon), 1026 ppm at BOL (equilibrium xenon), 450 ppm at MOL, and 0 ppm at EOL). The reactivity reduction due to the additional boron (3000 ppm minus the initial boron concentration) was calculated by assuming a boron worth coefficient of -1.0 $\Delta k/k$ per 100 ppm and is shown as SI worth in Tables D.1 to D.4. This same boron worth coefficient was then used to calculate the reactivity increase due to dilution of the borated coolant. Because of the assumed constant boron worth coefficient for all values of boron concentration, the reactivity versus dilution relationship is linear and, therefore, only two states are shown in the tables: 25% and 50% dilution. For 3000-ppm boron in the core, the 25% dilution value corresponds to the reactivity increase associated with a 25% reduction in the total boron concentration (i.e., from 3000 to 2250 ppm). In the same way, the 50% value corresponds to a 50% reduction (3000 to 1500 ppm). If we further assume, for conservatism, that the entire volume of the unborated secondary water replaced an equivalent amount of borated primary coolant, these dilution values are then simply the volume ratios of the volume of water in one secondary loop to the volume of primary water as shown in Figures D.1 and D.2. The BOL, no xenon, full-power case results in the highest positive reactivity addition as seen in Figure D.1.

The total amount of boron in the core was varied parametrically to obtain a generic family of curves as shown in Figure D.2 for BOL, no xenon, conditions. The total primary system volume is approximately 6000 ft^3, and the volume of one of the SGs at full power (secondary side) is 2000 ft^3. Measurements of the boron concentration in the primary coolant at Prairie Island Unit 1 after the SGT tube rupture incident of October 2, 1979, indicated a total value of 2000 ppm. Therefore, based on this concentration and a secondary-to-primary volume ratio of 1/3, complete dilution of the initial primary system volume by one secondary loop is seen to result in approximately a 2.5% subcritical system from Figure D.2. Since Prairie Island is a two-loop plant and thus results in the largest secondary loop to primary volume ratio of any operating plant, this point represents the worst criticality state due to deboration as a result of an SGT rupture. It, therefore, appears that there is no short-term criticality problem as a result of a tube rupture.

The xenon buildup after shutdown reduces reactivity by about 2% in approximately 5 h, all of which is lost in about 24 h. The reactor then gains about 3% in reactivity due to xenon decay after another 24 to 72 h and may cause a criticality problem for cores with less then 2000-ppm boron concentrations.

Table D.1 Reactivity values during conditions of full power, BOL, no xenon, and 1359 ppm boron

Condition	Reactivity worth (% Δk/k)	Total reactivity (% Δk/k) (accumulated)
Reactor trip	-7.5	-7.5
Cooldown:		
Full power to hot standby	2.4	-5.1
Hot Standby to 68°F	2.3	-2.8
1500 ppm boron (total):		
SI: 141 ppm	-1.4	-4.2
25% dilution	3.8	-0.4
50% dilution	7.5	3.3
2000 ppm boron (total):		
SI: 641 ppm	-6.4	-9.2
25% dilution	5.0	-4.2
50% dilution	10.0	0.8
3000 ppm boron (total):		
SI: 1641 ppm	-16.4	-19.2
25% dilution	7.5	-11.7
50% dilution	15.0	-4.2
4000 ppm boron (total):		
SI: 2641 ppm	-26.4	-29.2
25% dilution	10.0	-19.2
50% dilution	20.0	-9.2

Table D.2 Reactivity values during conditions of full power, BOL, equilibrium xenon, and 1026 ppm boron

Condition	Reactivity worth (% Δk/k)	Total reactivity (% Δk/k) (accumulated)
Reactor trip	-7.5	-7.5
Cooldown:		
Full power to hot standby	2.4	-5.1
Hot standby to 68°F	3.3	-1.8
3000 ppm boron (total):		
SI: 1974 ppm	-19.7	-21.5
25% dilution	7.5	-14.0
50% dilution	15.0	-6.5

Table D.3 Reactivity values during conditions of full power, MOL, and 405 ppm boron

Condition	Reactivity worth (% Δk/k)	Total reactivity (% Δk/k) (accumulated)
Reactor trip	-7.5	-7.5
Cooldown:		
Full power to hot standby	2.9	-4.6
Hot standby to 68°F	5.6	1.0
3000 ppm boron (total):		
SI: 2550 ppm	-25.5	-24.5
25% dilution	7.5	-17.0
50% dilution	15.0	-9.5

Table D.4 Reactivity values during conditions of full power, EOL, and 0 ppm boron

Condition	Reactivity worth (% Δk/k)	Total reactivity (% Δk/k) (accumulated)
Reactor trip	-7.5	-7.5
Cooldown:		
Full power to hotstandby	3.4	-4.1
Hot standby to 68°F	7.8	3.7
3000 ppm boron (total):		
SI: 3000 ppm	-30.0	-26.3
25% dilution	7.5	-18.8
50% dilution	15.0	-11.3

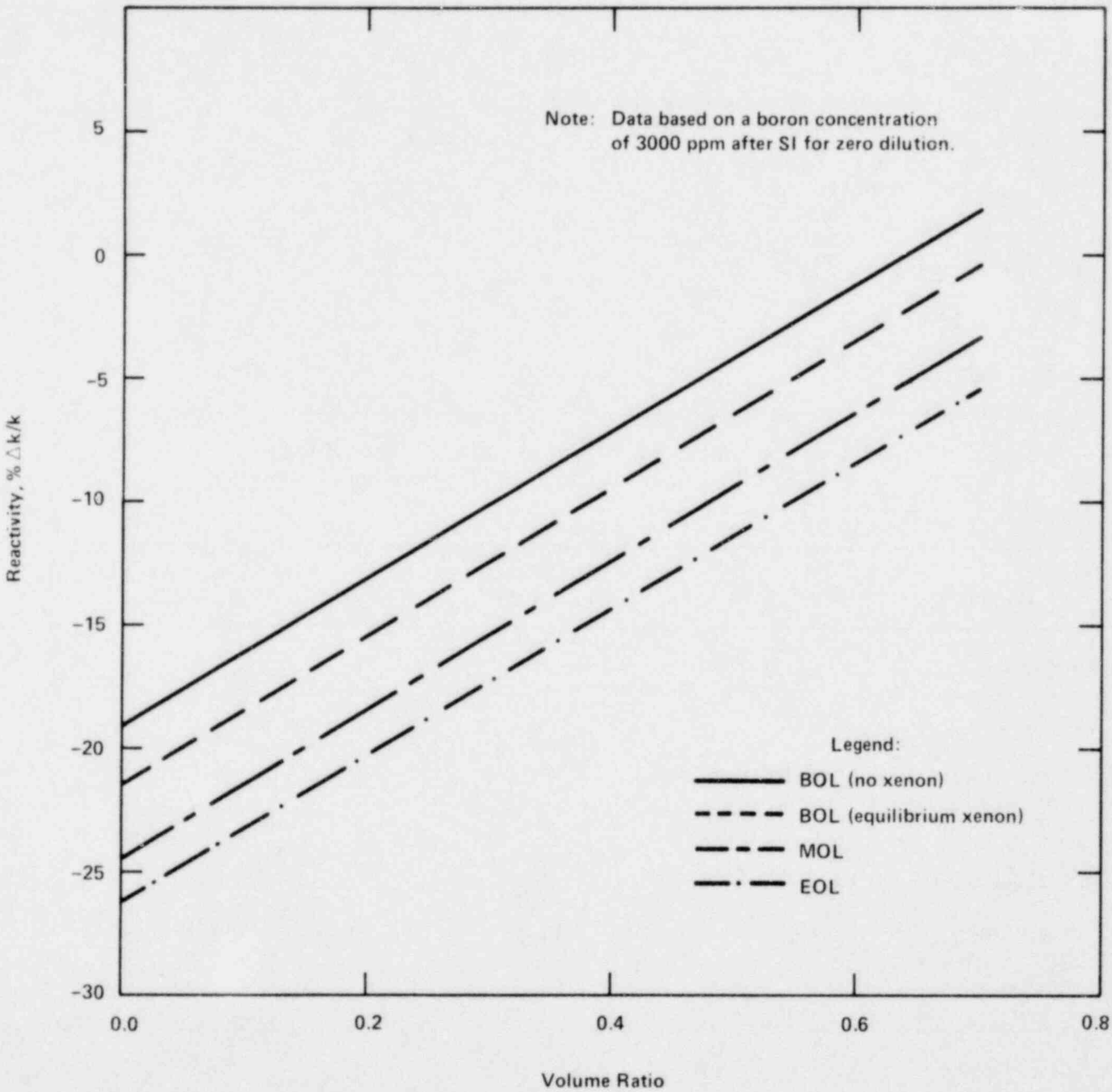

Figure D.1. Reactivity versus volume ratio of secondary to primary systems during full power

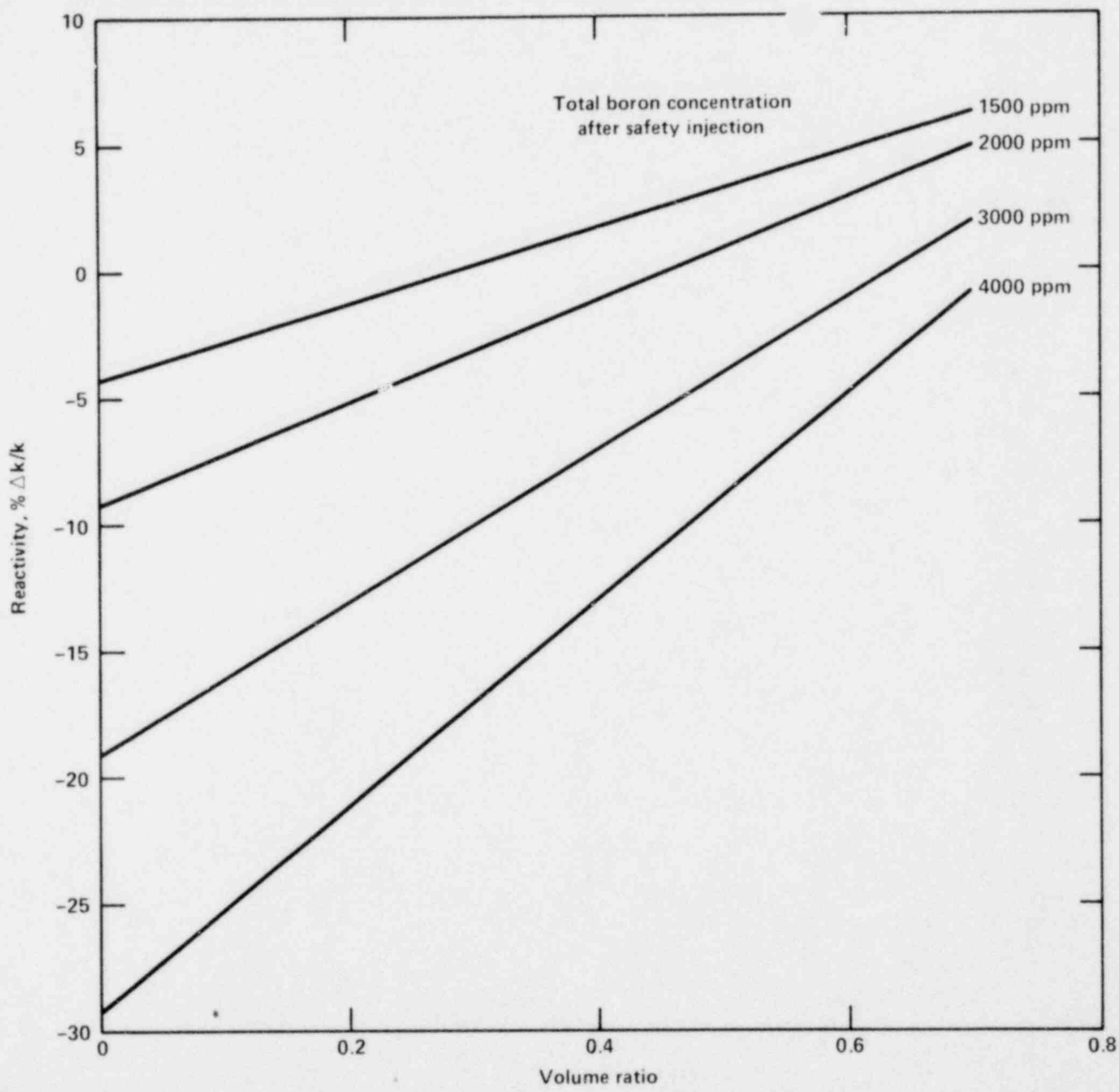

Figure D.2. Reactivity versus volume ratio of secondary to primary systems with varying boron concentrations after SI during full power, BOL, no xenon and 1359 ppm boron

APPENDIX E

SG PRESSURE AND LEVEL CONTROL SYSTEMS

1. SG PRESSURE CONTROL

1.1 Point Beach Unit 1

Each of the two main steam headers has four American Society of Mechanical Engineers (ASME) Code safety valves and an ADV. The four SVs are set to open at 1085, 1100, and 1125 (two valves) psig; all eight SVs pass a total of about 6.64×10^6 lbm/h saturated steam, or about 100% power.

The ADV has two modes of operation: (1) automatic opening at a preset, variable steam header pressure or (2) manual. The ADV is normally operated in the automatic mode with the pressure selected at about 1050 psig, which is below the lowest ASME Code SV setting. The main purpose of the ADV is to keep from lifting the SV, and to provide a means of SG pressure control and core decay heat removal without the availability of the condenser. The ADVs can together pass 660,000 lbm/h of saturated steam at about 1050 psig, which corresponds to about 10% power.

The normal steam dump system uses four steam dump valves off each steam header to the condenser. Each valve is an air-operated valve that is operated by a control system. The control system opens a variable number of steam dump valves depending on the difference, or error signal, between T_{AVE} and T_{REF}. The value of T_{AVE} varies from 547°F at no load to 580°F at full load; T_{REF} is a signal based on the turbine FSSP and varies from 551°F at no load to 582°F at full load.

The steam dump valves can also be set to control (during RCS cooldowns) SG header pressure. The operator selects the desired pressure, and the valves open depending on the differences between the actual and selected header pressure. The steam dump valves can also be manually opened from the control room. The steam dump valves can together pass 2.64×10^6 lbm/h saturated steam at 820 psig, which corresponds to 40% power.

1.2 Surry Unit 2

Each of the three main steam lines has five ASME Code SVs and an ADV. The total relieving capacity for the 15 SVs is about 11,100,000 lbm/h. This corresponds to approximately 100% of full power steam flow. In addition to the five SVs, each main steam line has an ADV that is power operated and has a variable setpoint. These valves are set to open automatically at 1035 psig and have a flow capacity of 373,000 lb/h, which gives a total relieving capacity of 1,119,000 lb/h, which is 10% of full power steam flow. The purpose of the ADV is to prevent the Code SVs from opening during the less severe anticipated plant transients. The setpoint for the ADVs of 1035 psig is about 50 psi lower than the setpoint of the lowest set Code SVs.

Excess steam generated by the residual and sensible heat in the core and the RCS is normally bypassed directly to the condensers by means of two 14-in. main steam bypass lines, which provide a total bypass capacity of 40% of normal full-load steam flow. Each bypass line contains a bank of four steam bypass control valves arranged in parallel. These valves are controlled by reactor coolant average temperature with provisions to control a portion of the valves with steam pressure. These valves are shifted to the steam pressure control mode after the unit has tripped and is being cooled down.

As long as a condenser vacuum permissive interlock is satisfied, all or several of the bypass valves open under the following conditions:

(1) On a large step load decrease, the steam bypass system creates an artificial load on the SGs, thus enabling the nuclear steam supply system to accept a 50 percent load rejection from the maximum capability power level without reactor trip. An error signal exceeding a set value of reactor coolant T_{AVE} minus T_{REF} will fully open all valves in 5 s. The value of T_{REF} is a function of load and is set automatically. The temperature-controlled valves close automatically as reactor coolant conditions approach their programmed setpoint for the new load.

(2) On a turbine trip with a reactor trip, the pressure in the SGs rises. To prevent overpressure without main steam SV operation, the turbine steam bypass valves open and discharge to the condenser for several minutes, to provide time for the RCS system to reduce the thermal output of the reactor without exceeding acceptable core and coolant conditions.

(3) After a normal orderly shutdown of the turbine generator leading to unit cooldown, the pressure-controlled bypass valves are used to release steam generated from the residual and sensible heat for several hours. Unit cooldown is programmed to minimize thermal transients and is based on residual and sensible heat release. It is effected by a gradual manual closing of the bypass valves until the cooldown process is transferred to the RHR system.

(4) During startup, hot-standby service, or physics testing, the pressure-controlled bypass valves are operated from the main control room.

In addition, a decay heat release control valve is provided that, after approximately half an hour, can release the sensible and core residual heat to the atmosphere via the RHR header. This valve is positioned from the main control room.

The valve is mounted in the common decay heat release header and provides service to all three SGs through 3-in. connections on each main steam line upstream of the nonreturn valve. In addition, this valve can be used to release the steam generated during reactor physics testing and operator license training; it can also be used to release steam while the unit is in the hot-standby condition.

1.3 Prairie Island Unit 1

The atmospheric dump system on each steam line consists of one 5-in. air-operated relief valve upstream of the MSIV and two 8-in. air-operated dump valves downstream of the MSIV. The 5-in. valve is automatically controlled by pressure or can be manually actuated from the main control board. These 5-in. valves have a capacity of 10% of maximum steam flow at 1100 psig. The 8-in. valves are controlled by a T_{AVE} error signal and provide a total relieving capacity of 30% of the steam flow at maximum load.

The capacity of the bypass system at Prairie Island Unit 1 is approximately 10% of the full power steam flow. The bypass system is also controlled by a T_{AVE} error signal.

When the SG is isolated by shutting the MSIV, steam cannot be released from the unit through the turbine bypass 8-in. valves. The only way the steam generated by the RCS sensible heat and core decay heat can be released is through the Code SVs and the 5-in. air-operated ADVs. The ASME Code SVs that can handle the full-power steam load are set to open at 1077, 1093, 1110, 1120, and 1131 psig.

2. SG LEVEL CONTROL

2.1 Point Beach Unit 1

After a reactor trip, the main feedwater control valve automatically opens completely to increase feed flow to both SGs to aid in reducing the RCS temperature to the no-load value. The valves remain fully open until one of the following conditions occurs:

(1) Abnormally high L_{SG}
(2) An SI signal
(3) $T_{AVE} - T_{REF}$ reduced to desired ΔT

The AFW system is composed of two TD pumps, one for each unit, and two MD pumps, which are shared by both units (i.e., both MD pumps feed a common header that supplies all four SGs with AFW). The TD pump is automatically started on (1) low-low L_{SG} in both SGs and (2) loss of 4-KV power supply to the normal feedwater pumps. Both the MD pumps are started on (1) low-low water level in any SG, (2) trip of both main feed pumps in either unit, or (3) safeguards sequence signal.

2.2 Prairie Island Unit 1

During normal plant operation, water level in the SG is controlled by two MD feed pumps, each of 8600 gal/min capacity. During an SGT rupture accident, the SI signal automatically terminates normal feedwater supply and initiates AFW addition. The AFW systems consist of two pumps: one MD and one TD. Each of the pumps has a 200-gal/min capacity.

APPENDIX F

MISCELLANEOUS SYSTEMS

1. SG BLOWDOWN

1.1 Point Beach Unit 1

Each SG has two 2-in. bottom blowdown connections for shell-side solids concentration control. The two connections are at the same elevation, but on opposite sides of the SG. Piping from the connections join, to form a 2-in. blowdown header for each SG. Each blowdown header has a hand shutoff valve and an air-operated trip valve. Each blowdown line also includes a manually adjusted needle valve for control of blowdown flow along with an SG sample line that taps into the blowdown line inside containment. In the event of a high radiation signal from radiation monitor R19, the air-operated trip valves close.

Flow from each SG blowdown header goes to a common blowdown tank, which has a vent condenser attached to the steam space to reduce the amount of iodine leaving the system in the event of a primary to secondary system leak. The water from the blowdown tank is processed using a 35-gal/min evaporator and other systems.

1.2 Surry Unit 2

Each SG is provided with blowdown connections for shell solids concentrating control. The three SGs associated with one unit are expected to collectively blow down 10,500 lb/h of steam under normal operating conditions.

In the original station design, blowdown from the three SGs of the unit passed to and flashed in the SG blowdown tank associated with that particular unit. The flashed vapor was discharged to the atmosphere through the tank vent while the condensate was normally drained by gravity to the circulating water discharge tunnel and, when contaminated, to the vent and drain system. The rate of blowdown from each SG is controlled by a manually operated needle-type flow control valve. A blowdown slip stream was taken from a point ahead of each flow control valve to produce a composite sample for radiation monitoring. If the radiation monitoring detects contamination exceeding 3.5 nCi/cc in the sample, an alarm is initiated in the Main Control Room. At this signal, the operator shuts off all blowdown in the affected unit and drains the associated SG blowdown tank to the unit and drain system. Individual SG blowdown samples are monitored separately to determine which SG is leaking.

In May 1977 the blowdown system for each unit was modified to eliminate the use of the flash tank and thus eliminate the discharge of flashed vapor to the atmosphere. The modified system consists of a blowdown heat exchanger and associated controls to depressurize and cool the blowdown for release to the circulating water discharge tunnel. The flash tank is valved out of service. The RMs remains as originally designed. A blowdown processing system consisting of a demineralization system to remove contaminates from the blowdown is being constructed and will be placed into service about May 1980. The processed blowdown will be recovered and returned to the condensate system for reuse.

1.3 Prairie Island Unit 1

Bottom blowdown from each of the two SGs is directed to the SG blowdown flash tank. The flash tank pump takes a suction on this tank and pumps the liquid through a heat exchanger and past the R19 radiation monitor. The flow then splits into two paths: to either the discharge canal (along with the flow from the other flash tank pump discharge) or into the SG blowdown (SGB) holdup tanks. The two SGB holdup tanks each have one own pump. Flow from these pumps is directed to either the hotwell condenser via an ion exchanger system or to the discharge canal via the ion exchanger system, an SGB monitor tank, and an associated pump.

Flow to the discharge canal from the flash tanks is automatically interrupted by the R19 radiation monitor if high radiation is detected. In this situation, flow is directed to the holdup tanks.

Flow to the discharge canal from the SGB monitor tank is monitored by another radioactive detector, R18.

The cause of these large differences is the staff's assumption regarding the various release paths. Since there was no radiation monitoring equipment at the major release points, the licensee could not determine the actual activity released. The staff, therefore, made conservative estimates for these release quantities. In particular, an overall decontamination factor of 100 for iodine released from the SG was assumed by the staff, compared to a factor of 2000 assumed by the licensee. (It should be noted that the staff considers its estimate as a conservative upper bound.) Because recurrence of SGT rupture accidents cannot be ruled out, it appears imperative to assure reasonably accurate measurement of the releases to the environs resulting from such an accident by installation of reliable radiation monitoring equipment at all release points.

Notwithstanding the sizable difference in estimated releases, the staff concurs with the licensee's conclusion that the offsite radiological consequences of the Prairie Island Unit 1 SGT rupture accident are small. The staff concludes that the offsite doses did not exceed 10 CFR Part 20 limits.

2. AIR EJECTORS

2.1 Point Beach Unit 1

The steam jet air ejector helps maintain vacuum in the turbine condenser by removing noncondensable gases. The air ejector jets are supplied with steam from the main steam line during startup. Two separate primary jets of the low-head, high-flow type are used to evaluate the condenser. The steam plus noncondensable gas mixture leaving the first stage jets are discharged onto the tubes of the intermediate stage condensers. When high radiation on the discharge is detected by the R15 radiation monitor, a high radiation alarm occurs but the air ejector discharge is not redirected.

2.2 Surry Unit 2

Each of the condenser steam jet air ejectors (two per shell) is designed to remove 12.5 ft^3/min of free air. Each ejector normally uses about 800 lb/h of steam at 150 to 200 psig from the auxiliary steam header, while using 900 gal/min of condensate for cooling. Separate hogging or vacuum priming jets are used to reduce condenser vacuum to 1 to 3 in. Hg abs during startup.

Vent gases removed from the condensers by the air ejectors are normally discharged through a radiation monitor to the atmosphere through the process vent. If an SGT ruptures, with subsequent contamination of the steam, the radioactive noncondensable gases would be detected by the radiation monitor located in the air ejector effluent line.

When the radioactivity level reaches the alarm setpoint of the monitor, trip valves in the air ejector effluent line will automatically actuate to divert the effluent flow to the containment and shut off the vent to atmosphere.

2.3 Prairie Island Unit 1

The steam jet air ejector helps maintain a vacuum in the main condenser by removing noncondensable gases. It has three first-stage elements and three second-stage elements mounted on the shells of the intermediate and after-condensers. Only two of the three stages are required during normal plant operation. The ejectors are supplied with steam from the main steam line. The discharge of the steam air ejector is monitored for radioactivity by the special radiation monitor.

APPENDIX G

COMPARISON OF POINT BEACH, SURRY, AND PRAIRIE ISLAND SYSTEMS

This appendix compares the systems of the three domestic nuclear plants that have undergone an SGT rupture accident.

Table G.1
Plant Systems Comparison

PARAMETER	Point Beach	Surry	Prairie Island
General:			
Licensed power (MWt)	1518	2441	1650
Plant capacity (MWe)	497	822	530
Loops	2	3	2
Loop isolation valves	None	2 per loop	None
RCS:			
Total volume (ft^3)	6040	8938	6191
Pressurizer volume (ft^3)	1000	1300	1000
Total RCS flow (10^6 lb/h)	63.6	100.7	68.2
RCP thermal input (10^7 Btu/h)	2.95	$\sim$3	2.27
T_{AVE}:			
No load (°F)	$\sim$551	547.0	547.0
Full load (°F)	$\sim$582	574.4	560.1
ΔT, full load (°F)	$\sim$60	62.8	63.6
Pressurizer level:			
Full load (%)	-	46	32.8
No load (%)	-	22	21.0
NOP (psig)	2235	2235	2235
Low pressure scram (psig)	1865	1860	1900
SGs and feedwater:			
Secondary water volume:			
Full load (ft^3)	1681	1688.5	1920
No load (ft^3)	2821	3581.8	3250
Steam pressure:			
Full load (psig)	821	770	770
No load (psig)	-	100[illegible]	1005

Note: See footnotes at end of table.

Table G.1 (Continued)

PARAMETER	Point Beach	Surry	Prairie Island
Number of U Tubes, each SG SVs:	3260	3388	3388
Number each SG	4	5	5
Setpoints (psig)	1085 1100 1125 1125	1085 1095 1110 1120 1135	1077 1093 1110 1120 1131
Flow rate, total for each SG (10^6 lb/hr)	3.332	3.723	3.873
ADVs each SG:			
Number	1	1	1
Operation	Automatic during high steam pressure (1050 psig) Manual	Automatic during high steam pressure Starts to open at 1035 psig; full open position occurs at 1085 psig Manual	Automatic during high steam pressure (1050 psig) Manual
Total Capacity (%power)	10	10	10
ADVs, other:			
Number and location	None	1 on common decay heat release header	1 on each steam header
Operation	-	Manual	Automatic ΔT control or pressure control
Steam dump (bypass to condenser):			
Operation	T_{AVE}-T_{REF} pressure control	T_{AVE}-T_{REF} control steam pressure control	T_{AVE}-T_{REF} control pressure control
Capacity, total (% power)	40	40	40
AFPs:			
MD:			
Number	2	2	2
Capacity, each (gal/min)	200	350	200
Automatic start signals:			
Low-Low Level in SG	Both SGs	2 out of 3 SGs	Either SG
Loss of power	-	All normal	Both 4.16-KV buses
Trip of main feedwater pumps	-	-	Yes
SIS	-	-	Yes

Table G.1 (Continued)

PARAMETER	Point Beach	Surry	Prairie Island
TD:			
Number	1	1	1
Capacity, ea (gal/min)	400	700	200
Automatic start signals:			
Low-low level in SG	Both SGs	2 out of 3 SG's	Either SG
Loss of power	Both 4-KV buses	Station service buses	Both 4.16 KV buses
Trip of main feedwater pumps	-	-	YES
SIS	-	-	YES
MSIV automatic closure modes, all lines:			
High-high containment pressure (psig)	30	25	17
High steam flow and low T_{AVE} (°F)	0.66 x 10^6 lb/h* and 540 and SIS	40% (at 20% load) 110% (at full load) and 541	DP $\cong$ 0.745 x 10^6 lb/h at 1005 psig* 540 and SIS
MSIV closure times (s)	5	5	5
Pressurizer:			
Volume total (ft³)	1000	1300	1000
Water volume full load (ft³)	600	780	600
Total heater capacity (kw)	1000	1300	1000
Normal spray flow, loop	Both	"A"; "C"	Both
Normal spray flow rate (ga/min)	300	575	400
Auxiliary spray flow rate	-	200	40
Restrictions on spray nozzle	320°F ΔT max	320°F ΔT max	-
PORVs:			
Number	2	2	2
Operation (psig)	2335	2335	2335
Flow Rate (10^5 lb/h)	1.79	1.79	1.79
Quench Tank:			
Rupture Disk Setting (psig)	100	100	99
Capacity (ft³)	800	1300	800
SIS:			
Low pressurizer pressure (psig)	1715	1700	1815
High containment pressure (psig)	≤ 6	≤ 5	≤ 4
Low steam line pressure (psig)	$\bar{5}00$	$\bar{N}A$	$\bar{5}00$

Table G.1 (Continued)

PARAMETER	Point Beach	Surry	Prairie Island
High steam flow and low T_{AVE} or low steam pressure	NA	40% (at 20% load) 110% (at full load) and 541° or 500 psi	NA
High differential pressure between steam line and header	NA	$\leq$ 150 psi	NA
HPSIPs:			
Number Required	2	2 out of 3 (charging)	2
Design flow (gal/min)	700	150	700
Design pressure (psig)	1120	2507	1082
Shutoff pressure (psig)	1500	2750	2207
Boron injection (with SIS)	Pumps take suction from BATs (20,000 ppm) then from RWST	One charging pump discharges through BIT (20,000 ppm)	Pumps take suction from from BATs (20,000 ppm) then from RWST
RWST:			
Capacity (10^5 gal)	2.75	3.5	2.75
Boron concentration	>2000	>2000	>2000
Design flow (gal/min)	1560	3000	2000
Design pressure (psig)	121	300	121
Shutoff pressure (psig)	145	-	147
Charging System:			
Number of charging pumps	2	3	2
Type of charging pumps	Positive displacement	Centrifugal	Positive displacement
Design pressure (psig)	-	2507	-
Design flow (gal/min)	60.5	150	60.5
Normal charging flow (gal/min)	30	45	30
Normal letdown flow (gal/min)	40	60	40
Normal RCP seal supply flow (gal/min)	16	24	16
Normal RCP seal return flow (gal/min)	6	9	6
Automatic letdown isolation	Low pressurizer level	Low pressurizer level <14.4%	Low pressurizer level

DP = differential pressure.
*Affected line only

APPENDIX H

DOEL UNIT 2 SGT RUPTURE EVENT

1. INTRODUCTION

On June 25, 1979, an SGT leak developed in SG "B" while the plant was heated to normal operating temperature and pressure and the reactor was shut down. The utility estimated the leak rate at about 135 gal/min. System pressure and pressurizer level began rapidly dropping and the second charging pump was manually started. Despite efforts to control the pressure and pressurizer level, automatic SI occurred on low system pressure concurrent with low pressurizer level. The high head SIPs caused RCS pressure to rapidly increase. The pressurizer PORV had been previously blocked so it was not available for pressure control. Normal pressurizer spray was initiated; however, this caused the pressurizer to become filled with water. The subsequent startup of the AFPs helped to cool the plant and reduce system pressure. The operators secured the SIS components and lined up normal letdown about an hour after the event.

After the primary pressure was reduced to about 440 psig, the RHR system was placed in operation and the plant brought to cold shutdown condition. Information regarding the radiological consequences is at present unavailable.

Subsequent SG inspection showed a longitudinal crack at the top of the U-bend on one of the Row 1 tubes, similar to the defect discovered in the Surry Unit 2 incident. The licensee plugged the faulted tube and several other tubes determined to be a potential source of leakage.

2. DESCRIPTION OF SGT RUPTURE

2.1 Nature of SGT Rupture

Doel Unit 2, located in Antwerp, Belgium, began commercial operation in November 1975. The unit is a 390-MWe PWR with two model 44 SGs designed by Westinghouse.

On June 25, 1979, while returning to power following a maintenance outage, an SGT rupture occurred in SG "B." The primary-to-secondary system leak rate resulting from the tube rupture was approximately 135 gal/min. The subsequent investigation indicated that the ruptured tube was located at Row 1, Column 24. The leak came from a longitudinal crack at the top of the U-bend.

2.2 SG Operating History

Doel Unit 2 has operated exclusively with AVT. The condenser cooling water of the unit is characterized as brackish, and the unit has full-flow condensate demineralizers and operates with continuous blowdown. In some isolated instances, chloride concentration in the SG blowdown reached 200 ppm. The condensers of the unit are currently being retubed.

The last SG inspection prior to the June 25, 1979, SGT failure was conducted during November 1978.

2.2.1 SG "B"

One thousand thirty-three tubes in SG "B" were eddy current inspected. Three hundred ten tubes were inspected over their full length while the remainder were inspected through the U-bend.

The tubes are expanded to only approximately 8 in. from the primary face of the 24-in. thick tube sheets. Thus, crevices that exist between the 16-in. unexpanded portion of the tubes and the tube sheet are exposed to the secondary coolant environment. The inspection revealed minor tube denting within these crevices:

Dent magnitude (mils)	No. of tubes
< 0.98	3
0.98 to 1.97	30
1.97 to 3.94	55
3.94 to 5.91	23
5.91 to 7.87	7

In 1977 the maximum dent magnitude at the tube sheet was approximately 4.72 mils while the maximum dent magnitude observed during inspections following the June 25, 1979, tube failure was approximately 18 mils. All of the dents were located in the region of the tube sheet where sludge had accumulated. The maximum depth of the sludge in 1978 was about 2.8 in.

Tubes that were examined showed no indication of denting in the tube support plates, and no hourglassing of the support plates was observed. There were, however, indications that the support plates were corroding.

Prior to the June 25, 1979, incident, no tubes had been plugged in the SG "B."

2.2.2 SG "A"

Prior to June 25, 1979, 25 tubes had been plugged in SG "A" as a result of tube leaks from within the tube/tube sheet interface crevices previously described. The exact cause of these leaks has not been identified.

Detailed results of the November 1978 inspection of SG "A" are not available.

2.3 Cause of the SGT Failure

Investigations revealed that the leak was located at the top of the U-bend of the Row 1, Column 24, tube of SG "B." Row 1 is the innermost row of tubes in the tube bundle, and Row 1 tubes have the tightest bend radius. Visual and video examination revealed that the Row 1, Column 24, tube had an axial crack located at tne top of the U-bend. During ECT, the largest probe to which the tube would allow passage was 0.689 in. while a 0.728-in. probe would not pass, indicating excessive ovality of the tube. To further quantify the degree of ovalization in the inner row tubes, various size ball bearings were pushed through the tubes. Ball bearings were used because of their precise dimensions and because the sharp bend radius of the inner row tubes does not interfere with passage of the ball bearings as it does with the passage of eddy current probes. The diameters of the two ball bearings were 0.704 and 0.717 in. Twenty-four tubes in SG "B" and 50 tubes in SG "A" would not pass the 0.717-in. ball bearing, but the 0.704-in. ball bearing passed every tube inspected.

The degree of ovalization is significant as it relates to the magnitude of tensile stresses on the inner surface of the tube. These stresses influence the susceptibility to stress corrosion cracking. Bending of small radius U-bends causes their cross section to become oval. The degree of ovalization increases with decreasing radius. Therefore, Row 1 and 2 tubes in all Westinghouse SGs are bent using an internal ball mandrel to limit the degree of ovalization and are not expected to have the degree of ovalization indicated by the gauging described. The Doel Unit 2 operators, therefore, have attributed the SGT failure to stress corrosion cracking resulting from an increase in tensile residual stresses due to excessive ovality of the tube. They believe the excessive ovality is a result of improper fabrication.

In addition to the ruptured tube at the R1-C24 location leaking in SG "B," the inspection following the event revealed a leaking tube and leaking tube plug in SG "A." The tube was leaking in the tube/tube sheet interface crevice.

2.4 Remedial Actions

In addition to plugging the leaking tubes, the tubes immediately surrounding the failed tube in SG "B" (tubes R1-C23, R2-C24, and R1-C25) and all tubes in SGs "A" and "B" that would not pass the 0.717-in. ball bearing were plugged.

3. DETAILED EVENT SEQUENCE

3.1 Description

The first indication of abnormal behavior was a rapid decrease of the primary system pressure (approximately 28 psi/min). The following sequence of events ensued:

	Time (min)
(1) Increase of charging flow demand, requiring startup of a second charging pump	1.8
(2) Automatic isolation of the CV letdown line	2.4
(3) Shutoff of the pressurizer heaters because of low liquid level in the pressurizer	2.4
(4) Closing of block valves in the pressurizer relief line	4.6

		Time (min)
(5)	Rapid increase of water level in the damaged SG (loop "B"); SG isolated	9.4
(6)	Startup of the third charging pump and realignment of the suction of all charging pumps from the VCT to the RWST	?
(7)	Shutoff of the main coolant pumps in loop "B" to reduce heat generation in the primary coolant system.	17.4
(8)	SI signal on low pressure in pressurizer followed by startup of diesels, containment isolation, and high pressure SI resulting in increase of the primary system pressure	19.2 to 19.5
(9)	Manual startup of the pressurizer spray in an attempt to decrease primary system pressure	28
(10)	Filling of pressurizer with water (level indicator off scale; no release of primary coolant from the pressurizer because block valve was closed and pressurizer did not exceed safety valve settings)	33
(11)	Automatic startup of AFW flow to both SGs	41
(12)	End of AFW to damaged SG	50
(13)	Beginning of depressurization of the primary coolant system--SIPs were stopped and the isolation valves in the letdown line were opened	68 to 88
(14)	Startup of the RHR system	195
(15)	Drainage of water from the secondary side of the damaged SG	

3.2 Discussion

The operator's actions during the accident were directed toward the following:

(1) Maintaining primary coolant subcooled

(2) Minimizing leakage rate between the primary and secondary coolant system

(3) Preventing radioactive fluid from escaping from the damaged SG

A sufficiently high degree of subcooling in the primary coolant system was achieved by reducing heat generation in the primary system (switiching off one main coolant pump "B") and by controlling, to the extent pissible, primary coolant pressure.

Two actions were taken to prevent radioactive fluid from escaping from the leaking SG. As soon as the leak was detected, the secondary side of the SG was isolated, and the setpoints of the ADVs were raised to their maximum value.

In general, the accident was handled in accordance with the existing procedures, and no radioactive releases or equipment damage was experienced.

All safety systems functioned as designed with the exception of the air-operated valves in the letdown line and in the line to the cooling system of the main pump thermal shields. The cause of this problem was that the containment isolation signal interrupted the supply of compressed air to these valves and rendered them inoperative until the air was manually restored. This malfunction of the valves resulted in a delay of primary system cooldown and depressurization (Item 13) and caused the primary coolant pumps to operate for a while without proper cooling. However, none of these events produced any detrimental consequences. The accident was successfully terminated using the presently existing procedures, which, with only one exception, proved to be adequate. The procedure dealing with containment isolation will have to be revised.

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16. ABSTRACT *(200 words or less)*

The NRC Staff's review of three domestic pressurized water reactor steam generator tube rupture events has shown that no significant offsite doses or systems performance inadequacies have occurred. The plant operators and systems successfully avoided direct releases to the environment (via the steam generator power operated relief valves or safety valves) and brought the reactor to a safe shutdown condition. However, a number of relatively minor procedural and equipment deficiencies were noted.

17. KEY WORDS AND DOCUMENT ANALYSIS

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