NUREG-1044

Evaluation of the Need for a Rapid Depressurization Capability for Combustion Engineering Plants

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

L. Marsh, C. Liang

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ABSTRACT

This report documents the NRC staff evaluation of the need for providing a rapid primary system depressurization capability, in particular by using a power-operated relief valve(s) (PORVs), in the current 3410-MWt and 3800-MWt classes of plants designed by Combustion Engineering (CE).

The staff reviewed the responses of licensees, applicants, and vendors to staff questions, supplemented by independent analyses by the staff and its contractors. The staff review led to the conclusion that, on the basis of risk reduction and cost/benefit considerations, no overwhelming benefit would result from requiring the installation of PORVs in CE plants that currently do not have them. However, when other unquantifiable considerations regarding the potential benefits of a PORV are factored into the evaluation, it appears that more substantial benefits could be realized. Given the more comprehensive studies currently under way to resolve the generic unresolved safety issue, USI A-45, Decay Heat Removal Reliability, the staff concludes that the decision regarding PORVs for these CE plants should be deferred and incorporated into the technical resolution of USI A-45. Resolution of USI A-45 will also include the effects of residual risks due to fires, floods, earthquakes, and sabotage.

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EXECUTIVE SUMMARY

This report documents the NRC staff evaluation of the need for providing a rapid primary system depressurization capability, in particular by using a power-operated relief valve(s), in the current 3410-MWt and 3800-MWt classes of plants designed by Combustion Engineering (CE).

This evaluation was performed for two reasons. First, informal reviews conducted since the accident at Three Mile Island, Unit 2 (TMI-2) (particularly by those done by the Nuclear Regulatory Commission (NRC) Advisory Committee on Reactor Safeguards (ACRS)) have suggested that power-operated relief valves (PORVs) enhance the overall capability of pressurized water reactors (PWRs) to accommodate transients and accident events. Secondly, all PWRs designed by other vendors (Westinghouse and Babcock and Wilcox (B&W)) include at least one PORV in their design.

The evaluation confirms the ability of these current designs without PORVs to meet regulatory requirements, with the exception of the possible single failures in the auxiliary pressurizer spray (APS) systems. It also compares the expected performance with and without PORVs for events that are outside the scope of those traditionally considered for licensing purposes. The evaluations performed were both probabilistic and deterministic, and they reflect engineering analysis and judgment. Also included are estimates of the value impact associated with the potential addition of PORV capability.

The results of the probabilistic analyses indicate that the frequency of core melts could be reduced from about 6×10^{-5} per reactor year to about 3×10^{-5} per reactor year by the installation of properly designed PORVs. The value-impact assessment suggests that there would be a real but not overwhelming advantage in equipping these plants with a rapid depressurization capability. The value of such a retrofit is not so large as to suggest unambiguous cost-effectiveness, nor does it suggest an urgent need for risk reduction.

In the final analysis, the decision as to whether or not PORVs should be installed in CE plants is a close call. As part of its program to resolve generic unresolved safety issues affecting nuclear power plants, the NRC staff is conducting a detailed study of shutdown decay heat removal requirements, designated USI A-45. However because USI A-45 is under way, the staff has concluded that the decision regarding PORVs for these CE plants should be deferred and incorporated into the technical resolution of USI A-45. Because part of the benefit of the PORVs was predicated on their ability to provide an alternate decay heat removal path (feed and bleed), any improvements in decay heat removal capability that might be promulgated as a result of the A-45 assessment could reduce the net benefit of PORVs. Finally, the events for which PORVs could prove to be of benefit are of low probability, and the staff is aware of no immediate safety concern associated with incorporating the PORV decision into the A-45 Program.

In the latter stages of the staff review of the need for PORVs, it was recognized that a rapid depressurization capability may affect the severity of core melts in progress; the consequences of core melts at high and low pressures were not compared. The technical aspects of this problem are complex, and they will be addressed in the Severe Accident Research Program being conducted by the NRC Office of Regulatory Research (RES).

ACKNOWLEDGEMENT

Several NRC staff members from the Office of Nuclear Reactor Regulation contributed to the evaluation documented in this report. To support the staff's overall evaluation consultants--including Argonne National Laboratory, Sandia National Laboratories, and Burns & Roe, Inc.--have performed independent studies in the areas of thermal hydraulics of steam generator tube rupture, multiple steam generator tube ruptures, and total loss of feedwater, and in the areas of probabilistic risk assessment, engineering feasibility, cost, operational impacts, and net benefits of PORV installation.

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L. Marsh and C. Liang of the Reactor Systems Branch, Division of Systems Integration, coordinated overall review of the CE PORV issue and preparation of this report, under the direction of B. Sheron, Chief of the Reactor Systems Branch. Significant resources from the USI A-45 program were used to provide input to this assessment in terms of evaluating the engineering feasibility, costs, operational impacts, and net benefits of adding PORVs to CE plants without them. A. Marchese, Task Manager for USI A-45, directed those activities. Substantial effort was provided by the Reliability and Risk Assessment Branch, Division of Safety Technology, in the PRA aspects of the staff review. The secretarial staff of the Reactor Systems Branch--particularly Bonita Gray and Gwendolyn Davis--provided much-appreciated typing support. The Phillips Building Central Word-Processing Unit typed the appendices to this report.

1 INTRODUCTION

Since the accident at Three Mile Island Unit 2 (TMI-2), the purpose and use of power-operated relief valves (PORVs) have been the subjects of considerable analyses and discussions. All PWRs designed by Westinghouse and Babcock and Wilcox (B&W) include at least one PORV. Although older Combustion Engineering (CE) plants also have PORVs, the current designs by CE do not include PORVs. There are two groups of CE-designed PWRs without PORVs: the 3410-MWt plants (San Onofre Units 2 and 3, and Waterford Unit 3) and the 3800-MWt plants (Palo Verde Units 1, 2 and 3, and other CE System 80 plants). Although Arkansas Nuclear One (ANO) Unit 2 also does not have a PORV, it was not part of this review because a large, manually actuated vent valve is installed on the ANO-2 pressurizer and could provide rapid depressurization capability. However, the actual performance and operability of this valve under depressurization or feed and bleed conditions have not been detrmined.

Although the preliminary review by the staff of the Nuclear Regulatory Commission (NRC) indicated that these plants met current regulatory requirements without the PORVs, other considerations--primarily accident management for events more severe than design-basis events and potential core melt risk reduction--prompted further consideration. The NRC Advisory Committee on Reactor Safeguards (ACRS) issued a letter stating its belief that a rapid depressurization capability should be considered for the current CE plants. The steam generator tube rupture in the Ginna plant emphasized the role of the PORV in accident management, and an internal NRC memorandum indicated the potential risk reduction benefits of a PORV (Rowsome and Murphy, January 29, 1982). Appendix A chronologically lists the events and issues leading to the staff study.

Because the PORV has a potential impact on safety, cost, and schedule, the staff embarked on a detailed systematic study of the need for a rapid depressurization capability in current CE plants without PORVs. The study focused on the concept of PORVs providing this depressurization capability because the staff believes that PORVs would provide the most flexible system.

During the course of this study, the operating license application for the San Onofre Unit 2 plant was brought before the Commission. The Commission expressed considerable interest in the staff's study and the relationship of the study and its conclusions to the decision before it. Although the Commission approved the San Onofre Unit 2 (SONGS-2) license, it also asked the staff to provide a formal report of the results of the study. This report documents the results of the study and the conclusions drawn.

2 AREAS OF CONSIDERATION

As stated above, the staff's preliminary review indicated that the current CE design without PORVs met all current regulatory requirements. Therefore, a major aspect of the study was to perform a more detailed review of the current CE design to confirm that the preliminary conclusion was valid.

A second area of the review involved the "unquantifiable" benefits associated with a rapid depressurization capability, such as enhanced accident management capability and reduced severity of accidents and transients.

A third aspect of the review was the evaluation of the risk reduction potential afforded by a rapid depressurization capability (or increased pressure-relieving capability). This involved probabilistic risk assessments (PRAs) both with and without PORVs.

Finally, from these three types of assessments, combined with other considerations, overall conclusions were drawn.

3 EVALUATION

This section presents the staff's overall evaluation of the need for a rapid depressurization capability in current CE-designed PWRs. As stated above, the staff focused its review on the need for a PORV as a means for rapid depressurization. The staff reviewed the responses of licensees, applicants, and vendors to staff questions, supplemented by independent analyses by the staff and its consultants. This evaluation was then augmented by an additional overall evaluation that considered not only the responses to the questions, but all review facets the analysts considered relevant. The overall evaluation addressed four topic areas. First, the staff determined if the CE plants met current regulatory requirements without a PORV. Second, the staff determined the extent to which the existing design without PORVs can mitigate events more severe than design-basis events, and whether a PORV would substantially improve the ability of the plant to mitigate or reduce the severity of these events. Third, a PRA was performed to estimate the change in core melt probability if a PORV were installed. And fourth, the cost and benefits were assessed and compared.

3.1 Compliance with Current Regulatory Requirements

This section evaluates, in the context of current regulatory requirements, whether current CE plants should install a rapid depressurization capability in general, and a PORV in particular. That is, are there any design-basis conditions or events in which a PORV is required so the consequences remain within acceptable limits (for example, departure from nucleate boiling ratio (DNBR) and maximum pressure limits in the case of transients and from the guidelines of Title 10 of the Code of Federal Regulations Part 100 (10 CFR 100) in the case of accidents)?

3.1.1 Steam Generator Tube Rupture

In the event of a steam generator tube rupture (SGTR), leakage from the primary system to the secondary system will eventually pressurize the secondary system. The secondary safety valves will then lift, allowing the leaked primary coolant to escape directly to the environment. To prevent this situation from occurring, the primary pressure must be rapidly decreased to stop the primary-to-secondary leakage. This depressurization can be accomplished in a variety of ways, including (1) the use of the normal pressurizer spray that is available only when the reactor coolant pumps are running; (2) the use of the auxiliary pressurizer spray, which does not require the reactor coolant pumps, but rather derives its flow from the charging pumps; or (3) opening the PORV and discharging steam from the pressurizer steam space.

The Westinghouse, B&W, and early CE-designed PWRs rely on the pressurizer PORV to accomplish this depressurization whenever the reactor coolant pumps are not operating. However, the current CE plants apparently rely on the auxiliary pressurizer spray system (APS) as if it were a safety-related system to keep the offsite radiological consequences within the regulatory limits. Because of its safety importance in accident mitigation, the APS system should be considered a safety-related system and should meet the single-failure criterion. During its review of the APS systems for CE plants without PORVs, the staff identified a number of possible single failures that could defeat the spray function. These potential failures are identified in Appendix B of this report. The staff review also determined that there are no Technical Specifications for the APS system, despite its being assumed in the mitigation of the SGTR accident. The staff has initiated questions to the near-term operating license (NTOL) plant applicants to determine if the APS is necessary for SGTR mitigation, if the system is subjected to the single failures identified by the staff, and if equipment modifications are necessary to eliminate the failures. Depending on the responses to these questions, Technical Specifications may be developed for the APS system.

The capability of the APS system to depressurize the reactor coolant system (RCS) following a design-basis SGTR was evaluated by CE, the staff, and Argonne National Laboratory (ANL) under contract to the staff. The evaluations, described in detail in Appendix B, showed that mitigation using either the APS system or a PORV results in acceptable offsite radiological consequences. Further, the consequences using either are about the same.

ANL also analyzed the consequences of the operator inadvertently filling the pressurizer water solid while depressurizing the RCS with the APS system. The ANL analysis showed that recovery from a water-solid pressurizer would be difficult but possible for the current CE plants. The ANL calculations also showed that the recovery could be enhanced by opening a PORV. The pressure would drop more rapidly, thus minimizing primary-to-secondary break flow. The steam volume in the pressurizer would reform, and the APS would be regained as a means of continuing depressurization. However, the rapid drop in RCS pressure would result in a rapid increase in the reactor vessel upper head void size, which could result in operator concern regarding core uncovery and potentially cause an operator error.

In the judgment of the staff, using the APS rather than a PORV to manage SGTRs has some advantages. The APS provides better pressure control and does not result in a net loss of inventory from the primary system. Overall, no clear improvement in the management of a single SGTR using a PORV was determined.

The current SGTR accident analysis for a CE-designed PWR assumes a double-ended guillotine rupture of a single tube in a single steam generator. On the basis of recent experience with tube failures in PWRs, the staff reviewed the continued acceptability of the single-tube-failure assumption. Information on water chemistry, corrosion, steam generator materials, and preheater section tube vibration was reviewed. These aspects are evaluated in detail in Appendix B, and summarized in Section 3.1.2, Steam Generator Integrity, below.

3.1.2. Steam Generator Integrity

Steam generator integrity plays an important role in determining the need for a rapid depressurization capability in current CE plants without PORVs. If the integrity of both steam generators were lost, rapid depressurization and initiation of feed and bleed cooling might be the only actions that would prevent either excessive offsite doses or a loss of all emergency core cooling (ECC) water.

Additionally, steam generator integrity has special relevance to SGTR accidents. Should the steam generator materials, water chemistry, inspection program, or susceptability to flow-induced vibration combine to significantly increase the likelihood of multiple tube ruptures, then the adequacy of the mitigation techniques of the current CE-plants would have to be assessed under these multiple-tube-rupture scenarios. Presently, safety analyses assume only a single broken tube in a single steam generator.

In response to questions about water chemistry, corrosion, and preheater section tube vibration, licensees and applicants supplied information that is described and evaluated in Appendix B, Sections 7, 13, and 14.

The combination of water chemistry controls, inservice inspection, preventive plugging of degraded tubes, and primary-to-secondary leak rate limits led CE and the staff to conclude that multiple tube ruptures (in one or both steam generators) do not lead to estimates of high risk to the public.

This conclusion also applies the possibility of flow-induced vibration in the preheater section of the CE System 80 steam generators is considered. CE performed a full-scale test of the economizer region was performed to investigate the vibrational response of the tubes when subjected to cross flow from feedwater inlet. From these tests, CE concluded that no detrimental tube vibration will occur.

3.1.3 Low Temperature Overpressure Protection

When the PWR RCS is in a cold shutdown condition, the maximum allowable pressure in the reactor vessel is low because of vessel irradiation and embrittlement. The inadvertent starting of a high pressure safety injection (HPSI) pump can result in an overpressure transient. To ensure that in these situations the maximum pressure remains below the limits specified in the Boiler and Pressure Vessel Code of the American Society of Mechanical Engineers (ASME Code), and specified in the license Technical Specifications, a low temperature overpressure protection system (LTOPS) must be available. The Reactor Systems Branch Technical Position (BTP) 5-2 (BTP RSB 5-2) in the NRC Standard Review Plan (SRP, NUREG-0800) states the functional requirements for this system, but does not specify a particular mitigation technique.

Most PWR designs utilize the pressurizer PORV as the means of mitigating low temperature overpressure transients. In these plants, the PORV setpoint is manually lowered to around 500 psig at low RCS temperatures, and, should the RCS pressure reach this value, the PORV opens to limit system pressure. In the CE plants without PORVs, low temperature overpressure protection is provided by relief valves on the shutdown cooling system (SDCS).

The SDCS design pressure is 650 psig, and the SDCS relief valves are set to open at 450 psia. The RCS design pressure is 2500 psia, and the pressurizer safety valves are set to open at 2500 psia. As discussed above, when the RCS is in a cold shutdown condition, the maximum RCS allowable pressure is significantly below the RCS design pressure, because of the reduced strength of the reactor vessel. The allowable pressure varies with RCS temperature and the amount of accumulated neutron fluence the reactor vessel has received.

The staff evaluated low temperature overpressure protection for plants concerned and reported its findings in the Safety Evaluation Reports for the plants (NUREGs-0712, -0787, -0852, and -0857). Although the staff did not ask the licensees and applicants questions about low temperature overpressure protection, the staff reviewed this aspect of plant design for two reasons. First, during an April 4, 1983 staff briefing, the Commission expressed concern about the status of the CE PORV study. Second, the French PWRs have experienced operational problems on their SDCS safety valves that may have relevence to the current CE-designed PWR SDCS relief valves. Each of these areas is described further and evaluated below.

During the April 4, 1983 staff briefing, the Commission expressed concern regarding the use of the relatively low design pressure SDCS for overpressure protection of the relatively high design pressure RCS. Keeping this concern in mind, the staff rereviewed the current CE design for providing low temperature overpressure protection. The staff's review determined that the safety valves provide mitigation for all credible events identified in the guidance in BTP RSB 5-2. The relieving capacities and setpoints of the SDCS safety valves ensure that the maximum SDCS pressure remains below the SDCS design pressure for these overpressure transients. Further, the SDCS safety valves provide acceptable RCS overpressure protection. However, as discussed below, the staff asked the ASME to clarify one point.

The SDCS and RCS are isolated by safety-related motor-operated isolation valves (MOVs). Each MOV is provided with interlocks that prevent the valve from being opened and closes the valves at a set of predetermined RCS pressures. The setpoint for the open permissive circuit is the SDCS design pressure. The setpoint for automatic closure is about 750 psig, which is above the design pressure of the SDCS. The autoclosure signal must be set above the SDCS safety valve setpoint to ensure that the SDCS is not isolated before the safety valves open to relieve pressure during an overpressure transient. The ASME Code specifies the open permissive setpoint but does not discuss the autoclosure setpoint. Because (1) the SDCS isolation valve autoclosure feature provides some measure of protection against overpressurization of the SDCS, (2) the setpoint in the current CE plants is above the SDCS design pressure, and (3) the ASME Code is silent on this aspect, the staff could not readily resolve the question of whether the CE plants are in compliance with the Code requirements.

In a recent meeting of the ASME Code Section III subgroup on pressure relief (Cherny, September 12, 1983), an NRC staff member discussed the RCS and SDCS isolation design interface using MOVs with autoclosure interlocks. The subgroup unanimously agreed that the configuration meets the intent of the ASME Code, even though the isolation valves are interlocked to close at a somewhat higher pressure than SDCS design pressure. As long as SDCS safety valve is sized to ensure that the pressure in the SDCS remains below 110% of design pressure during all credible overpressure transients, the design is adequate. The SDCS safety valves in current CE plants meet this criterion, as stated above.

On the basis of its review of the adequacy of the current CE plant design for RCS low temperature overpressure protection, the staff concludes that the use of the SDCS for RCS overpressure protection is acceptable, and the SDCS itself will not be overpressurized.

At the recent international meeting on decay heat removal systems in Wurenlingen, Switzerland (Marchese, July 14, 1983), operational problems in the French PWR SDCS were described. The French systems use Fisher safety valves, and there have been occasions where the valves have stuck open. The French are considering replacing these valves with SEBIM pilot-operated safety valves (Marsh, June 8, 1983).

The staff reviewed the domestic PWR SDCS operational experience reported in the last 3 years and found no cases where safety valves had stuck open. However, there have been two cases where safety valves of similar design have lifted and stuck open in other reactor auxiliary systems. Additionally, the staff has learned informally that the French safety valves that malfunctioned were qualified only for steam and not for water discharge. In this case, some malfunction would not be unusual. The SDCS safety valves in current CE plants are ASME certified for water discharge and are not the same type of valve as the French SDCS safety valve. A recent overpressure event at SONGS-2 resulted in actuation of one SDCS relief valve. The valve operated properly during the event, although the overpressure transient was not severe and it is unlikely the valve was exposed to maximum flow conditions. Although certified for liquid flow and apparently different in design than the French SDCS valves, the SDCS safety valves in current CE plants have a much larger relieving capacity than those on other PWRs.

When these safety valves were manufactured, the ASME Code permitted their capacity to be certified solely on the basis of calculations performed by the manufacturer. In response to NUREG-0737 Item II.D.1 the Electric Power Research Institute (EPRI) recently completed tests on full-size PWR primary system safety valves. The test results suggest that manufacturers cannot obtain a complete understanding of valve performance capability without some full-scale test or operational experience.

Although the staff is not recommending a complete full-scale test program for the SDCS relief valves in current CE plants, the staff has concluded that because of the very large size of the valves, proper value operation should be confirmed by evidence supported by test or operational experience to ensure the relief valves will operate, open, and close during all fluid conditions to which they could be exposed. The staff will pursue this matter with the licensees and applicants of these plants. The staff concludes that the LTOPS for CE plants meet the functional requirements of BTP RSB 5-2 and are acceptable, pending receipt of confirmatory information from the licensees and applicants.

In the course of re-reviewing the LTOPS design for the current CE plants, the staff noted that although the LTOPS meets the current regulatory criteria, there is a potential operation problem. As described above, the LTOPS relies on the relieving capacity of the SDCS relief valve, which is set at 450 psia. CE informed the staff that to satisfy reactor coolant pump (RCP) minimum suction pressure and seal pressure requirements, the RCS pressure must be above about 400 psig. Thus, there would be only about 50 psig to absorb any pressure increase experienced while the RCPs were starting. The SDCS safety valve setpoint may not be exactly 450 psig, and the valve may open or leak at a lower pressure.

CE informed the staff that, during the SONGS-2 testing program, as a result of SDCS safety valve weepage when the RCS (and SDCS) pressure was raised to satisfy the minimum pressure requirements for the RCPs, the RCPs could not be run. Apparently, the problem was solved at SONGS-2 by correcting the leaking SDCS safety valve. However, the staff notes that if the low temperature overpressure protection were provided by a pressurizer PORV, as it is in virtually all other PWRs, this problem would not arise. If a PORV were to leak, Technical Specifications permit the upstream block valve on that PORV to be closed, and the other PORV would provide overpressure protection.

In summary, although the use of the SDCS safety valve for RCS low temperature overpressure protection meets the current regulatory requirements, it may result in operational problems that would not necessarily arise if a pressurizer PORV were used.

3.1.4 Residual Heat Removal Systems

BTP RSB 5-1 states that current PWRs should have safety-grade systems capable of maintaining the RCS in the hot standby condition for 4 hours, followed by a cooldown to the cold shutdown condition. In PWRs other than the current CE-designed plants, depressurization of the RCS is accomplished utilizing either RCS fluid contraction caused by the cooldown, heat losses from the pressurizer to ambient, or by a safety-related PORV. The current CE plants apparently rely on the APS as if it were a safety-related system.

No specific questions were asked of CE or the CE owners regarding this aspect of plant design; however, the performance capability of current CE plants to achieve cold shutdown using only safety-related equipment (and, in particular, to accomplish depressurization using the APS) has been re-evaluated by the staff.

The capability of the APS to depressurize the RCS is discussed and evaluated in Appendix B. Neither the CE nor the ANL evaluations analyzed the performance of the APS in depressurizing the RCS to the cold shutdown condition. However, steady-state and transient calculations performed by CE assessed and suitably demonstrated the performance of the APS in depressurizing the RCS. Based on its evaluation of these calculations, the staff concludes that depressurization to the cold shutdown conditions with the APS is viable.

However, as discussed in Appendix B, the staff has identified certain potential single failures that would reduce if not eliminate the capability of the APS systems to depressurize the RCS. The staff has initiated questions to the CE NTOL plant applicants to address these potential failures. Until these staff concerns are addressed, the staff cannot conclude that the current CE plants meet the functional requirements of BTP RSB 5-1 for Class 2 plants, nor can they be considered to have demonstrated their ability to meet the 10 CFR 100 guidelines for the SGTR event as discussed in Section 3.1.1.

3.1.5 Auxiliary Feedwater ~~Reliability~~ System

As part of the staff consideration of the need for a rapid depressurization capability (in this case, in the context of effecting decay heat removal by the feed and bleed process), the staff reexamined the reliability of the existing auxiliary feedwater systems. The intent of this review was to ensure that no new information from the PRAs done by the staff or the CE owners group altered the staff's previous reliability and deterministic assessments of the auxiliary feedwater systems of current CE plants.

On the basis of this review, the staff concluded that the previous assessments remain valid and the staff's conclusions remain unchanged; no new information has been determined that alters the staff's previous analyses. The staff thus concludes that the auxiliary feedwater systems of the current CE plants meet the unreliability criterion of 10^{-4} to 10^{-5} per demand and the deterministic criteria specified in SRP Section 10.4.9.

3.1.6 Conclusions

On the basis of the above considerations, the staff concludes that, with exception of the potential single failures identified in the APS, the current CE plants meet current regulatory requirements. Mitigation of a single SGTR with either a PORV or with the APS results in acceptable offsite radiological consequences that are essentially the same. Further, mitigation using the APS has the advantages of providing a controllable depressurization technique and of adding fluid to the reactor coolant system. Multiple tube ruptures--as either an initiating event or as a consequence of other accidents--are of sufficiently low probability that they need not be considered as design-basis accidents.

3.2 Capabilities Beyond the Current Regulatory Requirements

This section contains the staff's analysis of the capabilities of the current CE-designed plants without PORVs to mitigate the consequences of multiple-failure accidents that are beyond the current regulatory requirements. The staff's analyses were conducted in two ways. First, the staff assessed the capabilities of the existing equipment and systems to mitigate specific multiple-failure accident scenarios. Second, based on the first analysis, the staff identified mitigation system failures and described how a PORV could either provide or enhance the necessary mitigation. The staff also evaluated how the PORV could aid both the operator and the plant in managing accidents beyond the current design basis.

The overall purpose of these evaluations is to determine if the existing systems are able to mitigate low probability (and perhaps high consequence) multiple-failure accident sequences and if a PORV would offer any significant net safety benefits.

3.2.1 Multiple-Failure Accident Scenarios--Equipment Failures

The staff requested CE to assess the ability of the existing systems, including a PORV, to mitigate multiple-failure accident scenarios beyond the design basis. CE's response is described in detail in Appendix B, Sections 5 and 8, and is summarized below.

3.2.1.1 Multiple Steam Generator Tube Ruptures (MSGTRs)

Should tubes rupture simultaneously in both steam generators, the offsite consequences could be greater than the design-basis SGTR because one of the damaged steam generators would have to be continually steamed to the atmosphere (assuming loss of offsite power so the condenser is not available) to remove core decay heat. The staff and CE evaluated these multiple tube rupture scenarios, and the staff compared the mitigation abilities of the APS to those of an assumed PORV. These analyses (described in Section 5 of Appendix B) generally showed that the offsite consequences would be about the same, whether a PORV or the APS were used for mitigation.

Both the staff and CE evaluated a simultaneous single tube rupture in each steam generator, and CE evaluated a simultaneous rupture of three tubes in each steam generator. The results of these assessments (Section 5 of Appendix B) show that the offsite doses are below the 10 CFR 100 limits.

Neither the staff nor CE evaluated tube ruptures more severe than three tubes in each steam generator, although there are indications that ruptures more severe than three tubes result in unacceptable consequences. CE stated that further analyses were not performed because of the extremely low probability of these scenarios. The staff evaluation of steam generator integrity (Section 3.1.5 below) resulted in the same qualitative conclusion.

ANL investigated the viability of performing feed and bleed decay heat removal rather than continually steaming a damaged steam generator. Although feed and bleed was successful in terms of limiting offsite consequences, the calculations showed that cooling of the RCS was slowed significantly as a result of the heat input from the damaged steam generator. The slow RCS cooldown would necessitate high pressure recirculation because of the expenditure of water from the refueling water storage tank (RWST). This operation would involve the containment sump supplying water to the SDCS pumps, which would supply the suction of the high pressure injection (HPI) pumps.

There are many undesirable aspects to this approach. First, the containment has been contaminated. Second, a small-break loss-of-coolant accident (LOCA) has been created, thus placing extra reliance on the HPI pumps for inventory control. Third, long-term recirculation requires valve alignments and equipment configurations not normally used. Considering the relatively low offsite dose using the normal means of cooling the RCS and the drawbacks associated with the feed and bleed operation, the staff has concluded that feed and bleed is not the preferred means of mitigating this scenario.

The staff did not assess the viability of feed and bleed in mitigating tube rupture events more severe than a single ruptured tube in each steam generator. For larger numbers of broken tubes, the offsite dose could be significant; thus, feed and bleed may become a desirable means of mitigating multiple simultaneous broken tubes in both steam generators. However, the probability of this scenario is considered to be extremely low.

3.2.1.2 Total Loss of Feedwater Events

The staff has reviewed the auxiliary feedwater system (AFWS) for the current CE plants and has found that it meets the staff's deterministic and reliability criteria (Section 3.1.5 above). However, because the CE design initially relies exclusively on the steam generators for the removal of decay heat, the staff asked CE to describe how a total loss of feedwater (TLOFW) could be mitigated.

CE responded that alternate low pressure feedwater systems could be used to add inventory to the steam generators. CE also addressed the mitigation capabilities of an assumed pressurizer PORV. These responses and the staff's evaluations are described in Appendix B, Sections 6 and 8.

Although the staff acknowledges the CE approach of providing alternate emergency sources of feedwater to the generators as a valid one, the staff also recognizes that reliance on the secondary side for decay heat removal involves not only the AFWS but also requires steam generator integrity and safety valve operability. Therefore, the staff examined the viability of feed and bleed as an emergency decay heat removal method, and contracted ANL to analyze a spectrum of TLOFW scenarios.

Two PORV sizes were studied: a small, a Calvert Cliffs-size PORV and a large, St. Lucie Unit 2-size PORV. The actual flow area could be achieved by a single valve or by a combination of many smaller valves. The ANL and CE calculations determined the time of core uncovery without any operator action and the latest time one of the following actions could be initiated to avoid core uncovery: (1) open PORV(s) to initiate feed and bleed, (2) steam generator blowdown to effect condensate pump supplied feedwater, or (3) regain AFW flow.

The ANL and CE results generally agreed and showed that feed and bleed must be initiated within about 20 to 25 minutes after the TLOFW for core uncovery to be avoided. Without feed and bleed, initiating steam generator blowdown as late as 55 minutes following TLOFW will avoid core uncovery. Thus, feed and bleed must be initiated about 30 minutes before the latest time SG blowdown could be initiated. The initiation of feed and bleed may, therefore, be unnecessary if the AFWS is restored, or if the steam generator blowdown is successful. However, the condensate pumps rely on offsite power and, as described in Appendix B, Section 6, the emergency-powered fire pump discharge pressure is too low to ensure that core uncovery is avoided.

The use of the condensate system depends on the availability of offsite power, local manual operation of selected condensate valves, and the operation of control-grade components. These limitations have been factored into the PRA (Section 3.3). Although procedures are not now available for the use of the condensate system in this situation, licensees and applicants have described general guidelines from which procedures could be developed.

Calculations performed by RES for another NRC program indicated that the use of the APS would not significantly alter the course of a TLOFW accident, without condensate flow, at the current CE plants without PORVs. The initial depressurization by the APS is not enough to lower RCS pressure to the point where significant HPI flow is added to the system. The APS would delay the time of core uncovery in 3800-MWt plants by only about 15 minutes.

A condition associated with alternate secondary side cooling is the addition of cold water to a hot, dry, steam generator. CE evaluated the effects of cold feedwater (condensate) addition to a hot, dry steam generator and determined that the steam generators would be able to withstand the resulting thermal shock. Also, the structural integrity of the steam generators would not be compromised even if condenser cooling water (a lower grade water) were used as steam generator feedwater during this situation.

In summary, the TLOFW event in which offsite power is retained can be mitigated by the condensate pumps as long as the steam generator atmospheric dump valves and the condensate system operate properly. There are uncertainties associated with the use of the condensate system for low pressure feeding of the steam generators. For example, there are no explicit procedures available in the plants for this technique. However, the staff will ensure these procedures are developed and implemented through the ongoing TMI action plan, Item I.C.1, Emergency Response Guidelines. Steam generator structural integrity is not compromised by the thermal shock associated with the addition of cold condensate water or by possible accelerated corrosion as a result of the addition of condenser cooling water, if it were done.

Nonetheless a PORV that can rapidly depressurize the primary system and allow feed and bleed cooling is very beneficial (1) to mitigate the consequences of other scenarios, including a TLOFW with loss of offsite power, and (2) to account for uncertainties, such as the operation of the condensate and ADV system.

3.2.1.3 Small-Break LOCA Without HPSI

Among the scenarios considered to be beyond the design basis is a small-break loss-of-coolant accident (SBLOCA) without high pressure safety injection (HPSI). CE analyzed three SBLOCAs: (1) one in which there is no operator action, (2) one in which there is RCS depressurization with a PORV and, (3) one in which there is RCS depressurization by aggressive cooling of the RCS with the steam generator ADVs. These cases are described in detail and evaluated in Section 5 of Appendix B.

The results of the CE study showed that core uncovery did not occur when the plant was depressurized by aggressive steam generator blowdown using the ADVs;

in contrast, core uncovery did occur (but no excessive fuel heatup occurred) when the plant was depressurized using PORVs. On the basis of these analyses, the staff agrees with CE that an aggressive secondary side cooldown is the preferred method of mitigating an SBLOCA without HPI. The use of the PORVs to depressurize the system will also mitigate the event, but the increased inventory loss through the PORV results in more core uncovery. As for other conditions, the PORV provides an added margin of safety in the event the ADV blowdown is not completely effective.

3.2.1.4 Pressurized Thermal Shock

The concern that the reactor vessel may experience excessive thermal shock as a result of cooldown and pressurization transients (pressurized thermal shock, PTS) is currently being addressed as an Unresolved Safety Issue (USI A-49). Scenarios presently thought to be of principal concern are multiple-failure scenarios.

Because the PORV could be useful in limiting system repressurization, the staff requested CE to evaluate the usefulness of the PORV for the mitigation of PTS events. CE's response, discussed and evaluated in Section 4 of Appendix B, analyzed steamline break accidents with break areas of 0.5 ft^2 and 1.29 ft^2 without the use of PORVs. The results of the analyses indicated that no crack initiation would occur during either transient even when the analysis considered a vessel radiation level corresponding to more than twice the design life of the plant. Preliminary results from the USI A-49 program, which did not include credit for use of a PORV to limit system repressurization, indicate no concerns for CE-designed plants. As long as the end-of-life reactor vessel nil-ductility transition reference temperature does not exceed the PTS screening criteria in the proposed PTS rule now in rulemaking (270°F for longitudinal welds or plate material, or 300°F for circumferential welds), the staff has found that no further actions are necessary to address the PTS concern. The end-of-life reference temperature for CE plants without PORVs is not expected to exceed the screening criteria.

3.2.1.5 Anticipated Transients Without Scram (ATWS)

The staff requested CE to address the potential benefits from a PORV in terms of mitigating anticipated transients without scram (ATWS) events. The CE response and staff evaluation are contained in Appendix B, Section 3. ATWS is currently beyond the regulatory requirements design basis, although there is pending rulemaking regarding the prevention and mitigation of ATWS scenarios.

A major safety concern in an ATWS event is excessive primary system pressure that can result in a major leak in the primary system and defeat of the HPI system because of deformed check valves in the injection line of the high pressure boundary. The limiting pressure for an ATWS is assumed to be 3200 psia, which corresponds to ASME Code stress level C. However, it is recognized that plants have the capability to withstand pressures in excess of level C.

The pending ATWS rule would require a diverse turbine trip for CE plants. The CE owners group calculations show that when credit is taken for the turbine trip but not for a PORV, the peak RCS pressure is greater than 3200 psia for only the 3410-MWt plants. The peak pressure for the 3800-MWt plants is about 2900 psia. Therefore, extra relieving capacity would be necessary for only the 3410-MWt plants. CE has calculated that an additional 0.10 ft^2 relieving area would be necessary to lower the peak RCS pressure to 3200 psia. This is about four times the relieving area of each St. Lucie Unit 2 PORV.

The staff notes that the use of a rapid depressurization capability to help mitigate the pressure peak in an ATWS requires a continuously aligned, fast-acting PORV. This may result in an increased risk from an SBLOCA induced by stuck-open PORVs. This issue is addressed as part of the PRA in the probabilistic risk (Section 3.4) and in Appendix B.

The staff also notes that the moderator temperature coefficient (MTC) used by CE in its ATWS calculations is a conservative value. The MTC will be more negative 95% of the time. Even though, for this MTC, the peak pressure reached in an ATWS exceeds 3200 psia (for the 3410-MWt plants), the addition of St. Lucie Unit 2-sized PORVs would be of benefit for ATWS sequences. The addition of the PORVs would increase the fraction of reactor operating time in which the peak pressure is less than 3200 psia.

In summary, additional relieving capacity would be necessary for only the 3410-MWt plants because the 3800-MWt plants meet the 3200-psia limit for 95% of the reactor operating times when credit is taken for the turbine trip. The installation of St. Lucie Unit 2-size PORVs would lower the peak pressure for the 3410-MWt plants to below 3200 psia for about one-third of the operating cycle; without the PORVs, the peak pressure would be above 3200 psia for virtually all of the operating cycle, even when credit is taken for turbine trip.

Again, the staff notes that there could be other ATWS scenarios that result in excessive peak pressures (greater than 3200 psia) that have not been identified or are currently considered to be too low in probability to be considered. The addition of PORVs on both the 3410- and 3800-MWt plants would increase their margin to accommodate a wide spectrum of ATWS events.

Additional Failure considerations.

3.2.2 ~~Multiple-~~Failure Accident ~~Scenarios--Mitigation System Failures~~

This section describes mitigation system failure scenarios beyond those considered in Section 3.2.1 above. These failures also are beyond current regulatory requirements because the mitigation systems generally meet the regulations. The failures are general and qualitative, and are more system functional failures than specific equipment failures. They show an additional aspect the staff considers to be appropriate in the assessment of the need for a PORV on current CE-designed plants.

The staff contacted plant operators and NRC training personnel to gain their perspective on possible techniques to mitigate the consequences of these failure scenarios and the potential benefits of a PORV. These considerations have been factored into the discussions below.

3.2.2.1 Limitations of the Auxiliary Pressurizer Spray System

The effectiveness of the APS in mitigating the consequences of scenarios both within and beyond the current regulatory requirements depends on the ability of the APS to depressurize the RCS. The staff review determined that there are potential single failures in the APS that could defeat the system's ability to reduce system pressure. These vulnerabilities are described in Appendix B, Section 1. The multiple-failure scenarios described below deal with the loss of the APS function as a result of additional malfunctions or operator errors that are more severe than those covered by the regulatory requirements.

(1) Water Solid System or Excessive Pressurizer Insurge

As discussed in Section 1 of Appendix B, system depressurization using the APS is only viable when there is a steam space in the pressurizer. During situations when there is a large pressurizer insurge, the depressurization capability of the APS is reduced significantly. Further, in scenarios in which the pressurizer steam space is lost altogether (for example, operator error in continually spraying while the safety injection system is in use), the APS is incapable of depressurizing the RCS. This results in extra reliance on the operator. To recover from this situation, the APS must be stopped, RCS cooldown continued with the steam generator ADVs, and the safety injection flow and reactor vessel upper head steam void size carefully monitored and controlled. Having a PORV in this situation may help. A PORV will always be able to lower system pressure, but may not efficiently regain the pressurizer steam space. However, plant operators and NRC training personnel noted that in terms of controlling plant pressure, an appropriately designed PORV would provide another means of lowering system pressure if the system became water solid or if there were an excessive pressurizer insurge.

(2) Unforeseen Malfunctions

With the exception of the single failure previously identified, the APS meets the staff's deterministic criteria and is judged to be an acceptable safety-related system. The staff did not identify any additional malfunctions that would totally defeat system operation. However, the APS relies on manual operator actions to align the fluid system valves, start the charging pumps (at Palo Verde Units 1, 2, and 3), and initiate and control the flow; a number of components must function properly, and the operator must take appropriate actions. Compared to the operation of a PORV, which would involve opening the block valve (if normally closed) and the PORV itself, operation of the APS involves more alignments and operator actions. Should there be unforeseen malfunctions or operator errors that have not been discovered by the staff's deterministic assessment, the APS may be limited in its ability to lower system pressure or unable to do so.

(3) Pressurizer Nozzle Fatigue

The results of CE's evaluation of fatigue usage of the pressurizer spray nozzle are in Appendix B, Section 1. The staff generally agreed with the techniques and assumptions associated with the CE analyses. The CE calculations are generally conservative; however, the staff notes that plants may operate in a way that makes the fatigue calculation less of a conservative, bounding-type calculation and more of a best-estimate calculation. There is nothing in a plant's Technical Specifications or Final Safety Evaluation Report that limits the number of spray cycles, and plants may choose to cycle the spray system (auxiliary spray or main spray) more frequently. This, in and of itself, may not necessitate the addition of a PORV, but the staff considers fatigue usage uncertainty one factor that should be considered when assessing limitations associated with the APS. A PORV or other means of rapidly reducing system pressure could always be used, and is not limited by pressurizer nozzle fatigue.

3.2.2.2 Redundant/Diverse Means of Core Decay Heat Removal

As discussed in Section 3.2.2, should there be a total loss of feedwater (which both the staff and the CE owners group consider highly unlikely), the condensate system could supply steam generator makeup. However, the condensate system relies on offsite power and a number of local, manual valve operations. In terms of plant safety, a rapid depressurization capability provided by a PORV or other relief path would provide the capability for feed and bleed cooling. Although not required by the current regulatory requirements, feed and bleed cooling is a redundant means of removing decay heat.

The use of the steam generators for the removal of decay heat is effective as long as the steam generators are available for energy removal. Should serious malfunctions occur in which the steam generator becomes unavailable, the PORV could provide a means of avoiding core damage. A feed and bleed capability enhances plant safety by enabling the removal of decay heat by a means other than the steam generator. It should be noted that a mission of reliable decay heat removal could dictate different design constraints on a PORV than would a mission of rapid RCS depressurization.

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3.2.2.3 Prevention of Pressurizer Safety Valve LOCAs

CE has stated that the high pressure reactor trip together with the steam dump system will prevent lifting the pressurizer safety valves for most anticipated operational occurrences. The staff evaluated this (Appendix B, Section 2) and generally agrees that if the steam dump system works properly, the safety valves would not lift. However, there are situations in which the steam dump system does not provide sufficient core decay heat removal. In addition, there is a low probability that pressurizer safety valves may fail to reclose after opening.

The safety significance of pressurizer safety valve lifts under these situations must be considered because safety valves cannot be isolated should they fail to close. A stuck-open safety valve after a transient constitutes a multiple-failure scenario because the combination of a passive failure in conjunction with a transient is beyond the current regulatory requirements. An automatically actuated PORV, with upstream block valves normally open and with a setpoint above the normal high pressure reactor scram, may avoid pressurizer safety valve LOCAs. It must be pointed out, however, that PORVs can leak, and, in fact, many plants with PORVs currently run with the block valves closed, negating this benefit of a PORV in this application.

3.2.3 Conclusions

On the basis of the analyses of selected multiple-failure accident scenarios that are beyond the current regulatory requirements, the staff concludes that with the exception of ATWS events without scram for the 3410-MWt CE plants, and loss of all feedwater events in both 3410-MWt and 3800-MWt CE plants, the existing systems should be able to mitigate the spectrum of multiple-failure accidents considered. However, there are limitations associated with the mitigation systems.

The capability of the APS to depressurize the RCS depends on the presence of a steam space in the pressurizer and on a number of operator actions. Also, although the staff has confidence in the deterministic assessment of the APS system, the staff recognizes the fact that there may be unforeseen malfunctions that render the system unable to control plant pressure.

Similar limitations can be expressed regarding the decay heat removal systems. The CE analyses showed that the condensate system is able to supply sufficient steam generator feedwater to avoid core uncovery. However, the condensate system relies on offsite power, and the steam generators themselves must be able to remove decay heat. In the event of loss of all feedwater, the steam generators may become unable to remove decay heat, and a suitably sized and properly operated pressurizer PORV could remove decay heat and avoid core damage. Similarly, the PORV could keep the pressurizer safety valves from lifting and prevent an unisolable LOCA.

On balance, although the staff recognizes that the existing systems can mitigate a number of multiple-failure accident scenarios that are beyond the current regulatory requirements, there are considerable uncertainties in this ability, and a properly sized PORV with a carefully chosen setpoint could provide defense in depth.

3.3 Probabilistic Risk Assessment (PRA)

To determine some quantitative measure of the change in safety that would result from the addition of PORVs, the staff asked CE for information necessary to estimate this change in a probabilistic way. The staff has reviewed CE's responses and had a staff consultant, Sandia National Laboratory, perform an independent analysis. In addition, the staff has performed its own probabilistic assessment.

CE performed plant-specific analyses for each member of the CE owners group. In general, the staff and the Sandia National Laboratory analyses considered only SONGS-2 and -3 design, but the staff ATWS analysis also considered the 3800-MWt design.

3.3.1 Scope of Consideration

All three studies included a quantitative analysis of the loss-of-main-feedwater event, including the loss of main feedwater caused by loss of offsite power. Steam generator tube ruptures (SGTR) were considered quantitatively in the CE and Sandia analyses; only the staff analysis included a quantification of the benefits from additional pressure relief for ATWS sequences. External events, fires, and floods were not considered in any of the studies.

Several additional potential benefits from the addition of PORVs were not quantified by CE, the staff, or Sandia. These include the possible limitation of challenges to the safety valves and the ability to depressurize the RCS while a core melt is in progress. This latter potential benefit would decrease the probability of failure of the steam generator tubes from steam overpressure when the core slumps into the lower reactor vessel plenum.

3.3.2 PORV Design Consideration

In its original submittal (CEN-239), CE considered only one type of feed and bleed system--one in which the PORV block valves are normally closed and in which each block valve requires power from a separate diesel generator. Because both PORVs are required for the success of feed and bleed, this limited the value of the feed and bleed system during loss of offsite power events. In addition, because the block valves are closed, the PORVs are not beneficial in reducing the peak pressure in an ATWS; such a design does, however, limit the frequency of PORV LOCAs.

Later results were communicated to the staff by telephone and then incorporated into Revision 1 of CEN-239. These results (from San Onofre Units 2 and 3) included the case of an automatic PORV design in which the PORV block valves are normally open. (In its CEN-239 submittal, CE had considered the increase in PORV LOCA frequency from the automatic PORV design, but had not considered the improvement in feed and bleed performance.)

Both the Sandia analysis and the staff analysis considered feed and bleed systems that were more reliable than the system originally considered by CE.

The Sandia analysis assumed that the block valves were normally closed, but that either diesel generator could power either block valve. The staff analysis assumed that the block valves were normally open. Thus, for the systems analyzed by both Sandia and the staff, feed and bleed success is possible with a loss of offsite power and failure of one diesel generator; for the system analyzed by CE, failure of a single diesel generator on a loss of offsite power transient results in feed and bleed failure.

3.3.3 Core Melt Sequence Frequencies

3.3.3.1 PORV-LOCA Sequences

The staff believes that, if the PORVs and their associated controls are properly designed and operated, the frequency of LOCAs as a result of stuck-open PORVs can be made negligible, even for the case where the PORV block valves are normally open. The sequence of most concern is the lifting of a PORV on a loss of offsite power. If the PORV should stick open, and if neither diesel generator started, there would be a LOCA and no way of mitigating it. The HPI system would be unavailable, and the block valves (operated by alternating current) could not be operated. To avoid this potential scenario, the opening setpoint of the PORV could be such that the PORV would lift during only a small fraction of loss of offsite power transients. Moreover, the block valves could be powered by direct current so a PORV could be isolated if stuck open. The PORV system arrangement in which the block valves are always open has the advantage of reducing the frequency of challenges to the safety valves, and gives additional pressure relief for ATWS sequences.

In its original CEN-239 submittal, CE had not correctly considered the lifting of PORVs on a loss of offsite power. In revised results for San Onofre, which have been incorporated into Revision 1 of CEN-239, CE estimated the frequency of PORV LOCAs, including those caused by loss of offsite power, as $4.1 \cdot \times 10^{-6}$/yr (median value) for the automatic PORV design and as 7×10^{-8}/yr for the case in which the PORV block valves are normally closed.

The Sandia analysis assumed a PORV system in which the block valves are normally closed. Thus, the Sandia analysis showed that PORV LOCAs resulted in a negligible core melt frequency.

3.3.3.2 Loss of Secondary Heat Sink Sequences

In their analyses, both the staff and CE have given credit for decay heat removal by use of the condensate pumps after depressurization of the steam generators (called the alternate secondary decay heat removal system by CE). The staff analysis assumes that there are procedures in place for the depressurization of the steam generators and use of the condensate pumps during loss-of-main-feedwater transients in which the auxiliary feedwater system is available. The Sandia analysis gives no credit for the alternate secondary decay heat removal system.

Tables 3.1, 3.2, and 3.3 show the results of the loss-of-heat-sink analyses performed by CE, Sandia, and the staff, respectively.

The importance of procedures for use of the alternate secondary decay heat removal system can be seen from the fact that if no credit is given for this system, the core melt frequency from loss-of-main-feedwater transients for a plant without PORVs would be about 6×10^{-5}/yr (mean value), instead of the value of 9×10^{-6}/yr given in Table 3.3. The net gain from adding PORVs, from the loss of secondary heat sink sequences, would then be 7×10^{-5}/yr, instead of 1.5×10^{-5}/yr.

3.3.3.3 Small-Break LOCAs

Both the Sandia and CE analyses show that the frequency of core melt sequences initiated by small-break LOCAs (SBLOCAs) is not appreciably changed by adding PORVs. However, both analyses assumed that an SBLOCA followed by failure of the HPI system would lead to core melt. There is, however, the possibility that PORVs could be used to depressurize the primary system, and low pressure injection systems used. Also, as described in Section 2.2, an aggressive cooldown of the RCS using the steam generator ADVs would avoid core uncovery. Thus, the assumption that an SBLOCA without HPSI results in core melt is a significant conservatism that ignores the thermal-hydraulic work performed for the analysis addressed in Section 3.2 above.

Table 3.1 CE core melt frequency results: SONGS-2 and -3

Initiator	With PORVs	Without PORVs
Loss of MFW combined with loss of offsite power	1.1×10^{-6}/yr, auto PORV	3.1×10^{-6}/yr
	2.8×10^{-6}/yr, manual PORV	

Notes:

1. Corrected values supplied by CE, reported in Revision 1 of CEN-239; see Appendix B.11.

2. Because of the PORV LOCA sequences, in the corrected analysis CE obtains an <u>increase</u> in core melt frequency 1.4×10^{-6}/yr from adding PORVs for the automatic PORV design.

3. These values are median values, not mean values.

Table 3.2 Sandia core melt frequency results

Initiator	With PORVs	Without PORVs
Loss of MFW	7.2×10^{-8}/yr	2.6×10^{-6}/yr
Loss of offsite power	5.5×10^{-6}/yr	7×10^{-6}/yr

Notes:

1. The values quoted are point estimate values, obtained from median point estimates of individual component failure probabilities.

2. The core melt probability as a result of SGTRs and SBLOCAs was calculated to be the same, both with and without PORVs. The Sandia analyses did not quantify the ATWS sequences.

Before credit can be given for aggressive cooldown for the RCS, appropriate procedures must be in place. The frequency of SBLOCAs with failure of the HPI system is approximately 1×10^{-5}/yr, assuming an SBLOCA frequency of 2×10^{-2}/yr and an HPI system unavailability of 5×10^{-4}/per demand. Thus there would be appreciable benefit from having the procedures in place and having personnel trained in their use.

Table 3.3 Staff core melt frequency results

Initiator	With PORVs	Without PORVs
Loss of MFW	1.7×10^{-6}/yr	9×10^{-6}/yr.
Loss of offsite power	6×10^{-6}/yr	1.4×10^{-5}/yr

Notes:

1. The net gain from PORV is 1.5×10^{-5}/yr (mean with an error factor of 36) from these sequences. The median value is 1.4×10^{-6}/yr.

3.3.3.4 ATWS

For ATWS sequences, the staff quantified the benefits of installing PORVs by estimating the reduction in the frequency of ATWS events in which the peak primary pressure exceeds 3200 psia. This frequency reduction ranged from 3.2×10^{-5}/year for a 3410-MWt plant without implementation of the ATWS rule to 2×10^{-6}/year for a 3800-MWt plant in which the ATWS rule was implemented. The assumption was made that two PORVs sized for decay heat removal were added. The results are given in Table 3.4.

3.3.4 Net Change in Core Melt Frequency from Adding PORVs

The overall net change in core melt frequency from the addition of PORVs, as given by the CE owners group in CEN-239, was less than 10^{-8}/yr for San Onofre Units 2 and 3. After CE corrected certain inconsistencies identified by the staff, the core melt frequency from loss of heat sink sequences was decreased by 2×10^{-6}/yr as a result of adding PORVs (for the CE automatic PORV system). (This is an approximate result obtained by taking the differences of median values.) However, PORV LOCA sequences more than counterbalanced this reduction in the revised CE analysis, with the result that adding the CE automatic PORV design resulted in an increase in the core melt frequency of 1.4×10^{-6}/yr (median value). Adding manual PORVs (block valves normally closed) leads to a decrease in core melt frequency of 1.3×10^{-7}/yr, according to the CE analysis.

Table 3.4 Staff core melt frequency results for ATWS sequences*

Assumption	3410-MWt plants	3800-MWt plants
ATWS rule not implemented	3.2×10^{-5}/yr	5×10^{-6}/yr
ATWS rule implemented	1×10^{-5}/yr	2×10^{-6}/yr (below 3200 psi 95% of the time without additional relief area.)

*Change in the frequency of ATWS sequences, in which pressure exceeds 3200 psi, by adding two PORVs, with .0228 ft^2 area per valve.

Notes:

These estimates assume the primary system pressure exceeds 3200 psi. The value/impact analyses in Section 3.4 are based on the following assumptions:

1. The ATWS rule is implemented.

2. Although the conditional probability of core melt with high primary pressure in excess of 3200 psi is likely to be less than 1, the value/impact assessment assumes this value to be 1. A somewhat lower value would have negligible impact on the results.

The Sandia analysis indicated that the net decrease in core melt frequency was 4×10^{-6}/yr (this is a point estimate based on median value of component failure rates, as opposed to a true median value of the decrease in core melt frequency).

The staff analysis showed a net decrease in core melt frequency of 1.5×10^{-5}/yr (mean value) from non-ATWS sequences; the median value was 1.4×10^{-6}/yr.

Differences in the analysis results may be attributable to the assumptions about differences in the frequency of loss of offsite power and the probability of recovery of offsite power, and about differences in the PORV and the block valve design/configuration.

The results of the staff analysis of ATWS core melt frequency are given in Table 3.4.

3.3.5 Conclusions

The staff's best-estimate calculations showed that if PORVs were installed on CE plants, the core melt frequency would be reduced by about a factor of 2, from 6×10^{-5} per reactor year to 3.5×10^{-5} per reactor year for the loss of heat sink and ATWS sequences. These are mean value estimates that combine the results of ATWS and non-ATWS sequences (the latter being the principal contributor).

Because mean values (1) offer better balancing of total costs and total benefits, (2) allow some objectivity to the uncertainties, (3) are more amenable to algebraic manipulations, and (4) are commonly used by other industries, the staff believes it more appropriate to use means instead of the medians in its cost/benefit assessments.

The accident sequences for which PORVs could avert core melt are those for which some ac power is available. Containment heat removal systems are likely to be operable so that offsite radiological consequences are not judged to be large, provided the containment does not fail as a result of a hydrogen burn or containment isolation. Therefore, a major incentive for adding PORVs is the result of their providing greater operational flexibility in upset events and in their helping to avert core damage generally associated with modest offsite consequences.

3.4 Value/Impact Analysis

3.4.1 Background

This section presents a summary of the staff's evaluation to determine if the installation of PORVs in CE plants lacking such capability would represent an important safety improvement. It includes an assessment of the value/impact or benefit/cost of such an installation. Although the method used has a quantitative emphasis, the calculated numerical values are used only as an aid to the decision-making process, and are not intended to be used as the final decision-making criterion on this issue. The values are, therefore, considered a supplementary tool to provide additional insight in an overall evaluation of this issue.

The safety importance is represented as a reduction in the probability of core melt and reduction in risk (man-rem) to the public that would result from the installation of PORVs to those CE plants lacking such capability.

This evaluation utilizes the results of the staff's probabilistic risk assessment (PRA) and cost evaluation presented separately in Section 3.3 and Appendix B, Section 12, respectively. In addition to those results, the methods developed in NUREG/CR-2723 are used to estimate the consequences of potential reactor accidents with specific application to the CE PORV issue.

A comparison of the staff's independent cost/benefit results with those of the CE owners group is shown in Table 3.5. In addition to showing the change in core melt frequency and PORV installation costs, the table also compares the installation time and estimated costs of replacement power. With respect to the change in core melt frequency resulting from the addition of PORVs, there is a considerable difference between results obtained by the staff and those obtained by the CE owners group. The reasons for the differences are discussed in detail in Section 3.3. Considering the costs of adding a controlled depressurization system, there is reasonable agreement between the staff's estimates and those of the CE owners group. An exception is the owners group's estimates for replacement power costs, which the staff considers to be conservatively high and unsubstantiated, as discussed in Appendix B, Section 12.

3.4.2 Risk Reduction

Table 3.6 summarizes the results of the risk reduction that would result from the installation of PORVs. The core melt release categories are based on CRAC-2 results for SONGS-2, as described in NUREG/CR-2723. Release category SST1 essentially involves the loss of all installed safety features and direct breach

Table 3.5 Comparison of cost/benefit analysis results

Organization	Change in core melt frequency (per reactor-yr)	PORV installation costs per plant ($ million)	Time to install PORVs (days)	Replacement power costs per plant to install PORVs ($ million)
NRC staff				
Case 1: before plant operation	2×10^{-5}	2.5	60	0 to 3
Case 2: after plant operation		4.3	60	
SONGS-2 and -3 (Southern California Edison Co.)	(1×10^{-7})*	2.3	42	2 to 35
Waterford 3	(1.1×10^{-6})**	2.3	80	3 to 30
Palo Verde 1, 2, and 3	(1.6×10^{-7})**	5.54***		2 per unit

Notes:

*This is a revised number, obtained from CE by telephone for the case of manually operated PORVs. For the case of automatic PORVs, CE predicts an increase in core melt frequency from the addition of PORVs, because of the PORV LOCA sequences.

**These changes in core melt frequency are being revised by CE.

***For all three units, during a refueling outage.

Table 3.6 Risk reduction from PORV installation (SONGS-2)

Plant	Release category	Release (man-rem)	Probability of containment failure	Reduction in core melt frequency per ry	Remaining plant life (yr)	Averted risk (man-rem)
SONGS-2	SST 1	3.3 E+7	3.0E - 2	2.0 E-5	40	790
SONGS-2	SST 2	2.8 E+6	1.0E - 2	2.0 E-5	40	20
SONGS-2	SST 3	8.8 E+3	9.6E - 1	2.0 E-5	40	70
Total						880

of the containment. Release category SST2 involves failure of the containment to isolate, but with proper operation of the fission product release mitigation systems. Release category SST3 involves failure of the containment by basemat melt-through with release mitigation systems operational. The release values provided in NUREG/CR-2723 for these release categories were calculated using the population distribution and meteorology for the SONGS site. The man-rem dose calculated for SONGS-2 in NUREG/CR-2723 represents the total population dose commitment

For SST1, SST2, and SST3 radioactivity release categories (as used in NUREG/CR-2723), the probability that containment failure would lead to a release in those categories was assumed to be 0.03, 0.01, and 0.96, respectively. The value of 0.03 represents the probability of early containment failure (Meyer and Pratt, 1983) by a hydrogen burn; the value of 0.01 represents the probability of containment isolation failure (NUREG/CR-1659); and the value of 0.96 represents the probability of containment failure by basemat melt-though and/or long-term containment leakages (Meyer and Pratt, 1983). The value of the probability of containment failure by hydrogen burn is for the case in which the containment sprays are available for a large, dry containment. For those sequences in which PORVs can help avert core melt, some ac electric power is available and, therefore, containment sprays are likely to be available. Table 3.6 shows that the averted risk (man-rem) with the installation of PORVs, considering a 40-year plant life for SONGS-2, is about 880 man-rem

3.4.3 Implementation Costs

The costs for installing a depressurization system such as PORVs range from about $2.5 million in a plant that has not operated to $4.3 million in a plant that has operated for some time. As discussed in Appendix B, Section 12, there exists the possibility that testing of the depressurization system could be on the critical path and, therefore, could extend a normal outage by 2 to 3 days. The estimated cost of replacement power based on $800,000 per day for 2 days of system testing is $1.6 million.

3.4.4 Maintenance Costs

The estimated costs of maintenance and repair of the installed PORVs over the life of a plant were considered. Maintenance and repair times for PORV/block valves are expected to require approximately 50 personnel hours per reactor year. Generally, based on operational history from two PWRs over a total of 6 years, maintenance and repair involves lapping valve seats, recalibrating, testing, repacking, and repairs to miscellaneous valve parts. The maintenance labor, overhead, and materials costs are estimated at $5300 per reactor year. This estimate is based on $100,000/man-year labor and overhead costs. The overhead costs ($600) are estimated to be 30% of the labor costs ($1900). The materials costs ($2800) are estimated to be 150% of the labor costs. Maintenance costs are assumed to be yearly recurring costs over 40 years. In present-day dollars, based on a 4% real discount rate (the difference between rate of inflation and the rate of debt interest), the estimated maintenance and repair costs for 40 years total $0.1 million.

3.4.5 Outage Costs

The outage costs resulting from PORV/block valve malfunctions have contributed to plant capacity losses of approximately 0.11% in operating PWRs (Electric Power Research Institute, (EPRI)-1139). Assuming that the PORV/block valves will be safety grade, these losses are estimated to be reduced by 50% and the capacity losses for PORVs installed in the CE design should not exceed 0.2 outage days per reactor year. Considering a replacement power cost of $0.8 million per day for SONGS-2, the replacement power cost resulting from outages attributed to the installed PORV is estimated at $0.16 million per plant year. The cost of replacement power is assumed to be a recurring cost extending 40 years into the future. The estimated present worth (costs), based on a 4% real discount rate, is, therefore, $3.16 million.

3.4.6 Accident Avoidance Costs

The costs of accident avoidance resulting from the potential reduction in core melt frequency using cleanup and replacement power costs as described in NUREG/CR-2723 as onsite costs, adjusted to $800,000 per day for the costs of replacement power, would result in an accident avoidance cost of $1.4 million.

3.4.7 Occupational Radiological Exposure

The installation and maintenance work described above would result in an occupational radiological exposure (ORE) to persons working in the radiation field (of about 0.15 rem/hr) near the pressurizer safety and block valves. The ORE resulting from installing PORVs in an operating plant is estimated at 400 man-rem. The ORE from PORV maintenance and repair, assuming 50 hours per reactor year over 40 years, as discussed above, is 300 man-rem.

ORE in post-core-melt accident cleanup, repair, and refurbishment is estimated at $2X10^4$ man-rem (NUREG-0933). Installation of PORVs that results in a reduction in core melt frequency of $2.0X10^{-5}$ per reactor year results in an avoided ORE of $(2X10^4)(2.0X10^{-5})(40)$ or 16 man-rem, considering a 40-year reactor life. Therefore, the ORE risk of post-core-melt accident cleanup is not a major factor with respect to installation of PORVs.

3.4.8 Other Considerations

At the present time, the staff does not have a policy or rule-of-thumb to determine a dollar equivalence of offsite effects. The offsite effects may include early fatalities, early injuries, latent cancer fatalities, and property damage. The actual benefit from averting those effects is highly uncertain and largely unquantifiable. In addition, there are such indirect effects as national economic repercussions (e.g., closing of other nuclear power plants), effects on the finanical market, and provisions for health care and medical treatment for the affected population. Considering all these effects would enhance the overall value/impact ratio. However, as indicated in Note 2 to Table 3.7, these omissions are not quantified in the following value/impact assessment.

Table 3.7 Value/Impact (benefit/cost) results

Values (Benefits) [1,2]		Impacts (Costs) [2,3]	$millions
Reduction in core-melt frequency	$2x10^{-5}$/ry	Installation	+4.3
		Replacement power during testing	+1.6
Reduction in public risk	+880 man-rem	Replacement power during outages	+3.2
		Recurring maintenance	+0.1
Subtotal	+880 man-rem	Subtotal	+9.2
ORE[4], installation	-400 man-rem	Accident avoidance (cleanup and replacement power)	-1.4
ORE, maintenance	-300 man-rem		
ORE, accident avoidance	+ 16 man-rem		
Subtotal	-640 man-rem	Subtotal	-1.4

Value/impact (not including ORE and accident avoidance $\cong \frac{880}{9.2} \sim 97 \frac{\text{man-rem}}{\$\ M}$

[1]Positive values indicate man-rem averted; negative values indicate man-rem burden incurred during installation and maintenance.

[2]Offsite effects such as potential reductions in offsite property damage, litigation, loss of jobs, medical treatment, loss of industrial capacity, etc., are not considered in this analysis because the various factors and uncertainties are not quantifiable at this time.

[3]Negative impacts indicate cost savings.

[4]ORE = occupational radiological exposure.

3.4.9 Value/Impact Assessment

The costs and other considerations discussed above are summarized in Table 3.7; they are used to aid in assessing the value/impact (V/I) ratio and safety importance of installing PORVs in the CE design. The V/I ratio is the quotient of the safety benefits (values) in terms of averted risk (man-rem) to costs (impacts). The averted risk resulting from a reduction in core melt frequency of 2.0×10^{-5} per reactor year is 880 man-rem for SONGS-2 (see Table 3.6). The PORV cost per plant (after operation) is $9.2 million. The resulting V/I ratio is 96 man-rem per $1 million. Thus the resulting V/I ratio provided only a marginal V/I when compared to the goal of keeping radiation releases as low as is reasonably achievable (ALARA) (as defined in Appendix I to Title 10 of the Code of Federal Regulations Part 50 (10 CFR 50)) of 1000 man-rem averted per $1 million (i.e., the reciprocal of $1000 per man-rem). It should be noted that the V/I ratio does not change if Units 2 and 3 are considered either separately or combined.

It must also be recognized that the V/I, as defined above, does not consider that the same population is subject to the combined risk reduction from Units 2 and 3. Based on this interpretation, the combined potential risk reduction of 1760 man-rem per reactor site, when considered independent of the V/I ratio, represents an important safety benefit.

In addition to the above V/I considerations and the averted risk per reactor site, the staff has determined that a given single issue that provides more than a 10% reduction in a total core melt frequency of 10^{-4} per reactor year is considered an important safety benefit. Therefore, the safety benefit related to a reduction in core melt frequency of 2.0×10^{-5} per reactor year (the reduction attributed to PORV installation) represents an important safety improvement.

3.4.10 Summary

Table 3.7 shows that a small but positive V/I ratio from the installation of PORVs at SONGS-2 and-3. However, if the values (benefits) described above as "other-considerations" were quantified, a higher V/I ratio would result. Therefore, recognizing the limits inherent in the quantitative V/I ratio and based on a potential reduction in core melt frequency of 2.0×10^{-5} per reactor year and a potential site-specific risk reduction of 1760 man-rem, the staff finds that the installation of PORVs would provide important safety benefits. The above assessment based on SONGS-2 and 3 also bounds the consequences for the same issue relative to Palo Verde Units 1, 2, and 3 and Waterford Unit 3.

4 CONCLUSION

4.1 Conformance with Current Regulatory Requirements

To verify the staff's earlier conclusions that the CE plants without PORVs meet the current regulatory requirements, the staff reassessed the ability of the plants to meet these requirements. As a result, the staff concluded

(1) The APS, together with the other design features, enables mitigation of a postulated single SGTR accident so that radiological consequences would remain below the guidelines dose value of 10 CFR 100. Further, a PORV would also provide adequate mitigation capability and result in about the same offsite radiological consequences as the SGTR mitigated by the existing APS.

(2) Potential single failures have been identified in the APS on the current CE-designed PWRs that may render the system unable to supply charging fluid to the pressurizer spray nozzle. Specifically, on plants other than SONGS-2 and -3, the loop charging valves that must be closed for charging flow to be diverted to the pressurizer for spray flow are manually operated. Similarly, on SONGS-2 and -3 a malfunction in the normal pressurizer spray valve, which is a control-grade component, diverts APS flow. In its requests for additional information, the staff is requiring these potential single failures to be addressed by the applicants of CE plants without PORVs.

(3) There are no Technical Specifications associated with the APS to ensure its operability and surveillance. Without such Technical Specifications, the staff cannot conclude that the system would be available when needed. The staff is requiring the applicants of CE plants without PORVs to

address the reliance placed on the APS, and, if they are necessary for meeting the regulatory requirements, Technical Specifications will be developed and implemented.

(4) In situations in which the pressurizer becomes water solid, the pressurizer steam space will re-form upon continuation of the cooldown with the safety-grade ADVs. The recovery would be a challenge to the plant operators, but would be within the capability of the existing systems. The size of the reactor vessel upper head void may be of a concern to the operator, although calculations show that at no time is core cooling jeopardized. A PORV may help, but no net advantage using this technique was determined.

In general, the staff believes that depressurization using the APS is preferable to using a PORV because the former involves the addition of mass to the system and the depressurization is more controllable. Use of the PORV results in a more rapid depressurization with the accompanying contamination of containment and the possibility of an SBLOCA. However, the staff believes that procedures and training should emphasize the recovery actions should the pressurizer be inadvertently filled water solid during a SGTR. The staff is incorporating this into the ongoing I.C.1 program.

(5) The staff's reassessment of the conformance of the current CE-designed PWRs to BTPs 5-1 and 5-2 confirmed that, subject to receipt of confirmatory safety valve performance information from licensees and applicants and resolution of the potential single failures in the APS, the current CE plants are in conformance with these BTPs. Similarly, the PRAs done by licensees, applicants, and the staff did not result in any new information that would alter the staff's earlier conclusion that the current CE-designed PWR auxiliary feedwater systems meet the reliability and deterministic criteria.

(6) The water chemistry programs, corrosion susceptibility, and the pre-heater section tube vibration (3800-MWt class plants only) have been evaluated by CE and by the staff. The staff finds that (a) steam generator integrity is adequate for these plants, (2) the assumption of only a single ruptured

tube in a single SG is adequate, and (3) the probability of multiple tube ruptures as either an initiating event or as a consequence of the accident is very low. However, the staff recognizes that the uncertainties in these determinations may be large.

Overall, the staff concludes that the current CE-designed PWRs meet the current regulatory requirements. However, the potential single-failure and the need of Technical Specifications for the APS should be addressed by the applicants of CE plants without PORVs.

4.2 Capabilities to Mitigate Multiple-Failure Accident Scenarios Beyond the Current Regulatory Requirements

As an additional aspect of its review, the staff reviewed the capabilities of the existing systems and components to mitigate multiple-failure accident scenarios that are beyond the current regulatory requirements. The contributions of a PORV in these accident scenarios were assessed, and the staff also considered the operational aspects of multiple-failure accident scenarios. As a result of this assessment, the staff concluded

(1) The current-design CE plants can mitigate multiple SGTR accidents that involve up to three broken tubes in each steam generator. The calculations indicated that (1) there were no unsatisfactory offsite doses, (2) the plant was adequately cooled, and (3) the operator could perform mitigating actions. Further, the staff determined that feed and bleed cooling using a PORV is a viable means (although not the preferred means) of mitigating multiple SGTRs (single ruptured tube in each steam generator). Long-term recirculation using the containment sump would be necessary to continue the RCS cooldown to the RHR system entry conditions. Because the offsite doses in the multiple SGTR accident analyzed were relatively low when the normal means of plant cooldown was used (steam generator blowdown), the staff believes that feed and bleed would not be the preferred means of mitigating this accident, although it does provide a diverse, additional means for cooling.

(2) Mitigation of a TLOFW can be accomplished using the safety-grade steam generator ADVs to reduce the pressure significantly to enable the non-safety-grade condensate system to supply water to the steam generators. However, the condensate system is powered only from offsite power and is not a safety-related system. The staff believes that the addition of PORVs for feed and bleed cooling can contribute significantly in mitigating the TLOFW event.

(3) For mitigation of a TLOFW, the emergency firewater pump at Waterford Unit 3 may not be able to add sufficient feedwater to prevent core uncovery because of the limited ADV capacity and the relatively low fire pump discharge head. However, scoping calculations showed that, although some uncovery did occur, the peak cladding temperature does not go above 2200°F. No credit was taken for the emergency firewater pumps of the other current CE-designed PWRs.

(4) In the most limiting TLOFW accident, two large-size PORVs of the St. Lucie Unit 2-size would have to be opened 20 to 25 minutes after the initiation of the event or about 30 minutes before the latest time that AFW recovery would keep the core from being uncovered. However, should the secondary heat sink not be recoverable for any reason, calculations performed by both CE and ANL show that feed and bleed is a viable means of removing core decay heat.

(5) SBLOCAs coupled with total loss of HPI can be mitigated by an aggressive RCS cooldown using the safety-related steam generator ADVs. No uncovery occurs, and the low-pressure safety injection tanks (SITs) and low pressure safety injection pumps (LPSIPs) provide makeup when RCS pressure is low enough. However, this conclusion assumes no analysis uncertainties. A PORV would provide significant defense in depth in protecting against this event.

(6) The staff believes that there are no significant concerns regarding pressurized thermal shock on the CE plants without PORVs. The results of conservative calculations showed that no crack initiation would occur in the worst case steamline break PTS scenarios.

(7) Assuming the implementation of the ATWS rule, only the 3410-MWt class CE plants would need extra relieving capacity to ensure the peak pressure following an LOFW ATWS remains below the ASME Code service level C limit, which is 3200 psia. The addition of PORVs sized to successfully accomplish feed and bleed would limit the pressure in the 3410-MWt plants to below the 3200-psia limit for about one-third of the operating life. Without the PORVs, the peak pressure would be above 3200 psia throughout plant life. PORVs would expand the range of ATWS scenarios that both the 3410-MWt and 3800-MWt classes of plants could safely accommodate.

From the above assessments and calculations, the staff concludes, overall, that a number of accident scenarios beyond the current regulatory requirements can be mitigated by the existing systems. Further, a PORV is able to mitigate a TLOFW by providing a feed and bleed capability. Also, a fast-acting, normally aligned PORV can mitigate ATWS scenarios to limit peak RCS pressure to below the ASME Code service level C limit of 3200 psia.

4.3 Additional Failure Considerations

Although the assessments done by the staff and by licensees showed that the existing systems are capable of mitigating selected multiple-failure accidents, there are both known and unknown limitations associated with these mitigation systems. The staff attempted to qualitatively assess the following limitations and potential failure scenarios:

(1) Limitations of the APS have been calculated in thermal hydraulic analyses and observed during LOFT and SONGS-2 tests. If the pressurizer insurge rate becomes excessive, the rate of depressurization from the APS is significantly reduced. Also, if the pressurizer becomes water solid, the APS is unable to depressurize the system. A properly sized and reliably powered PORV would be capable of lowering system pressure without these limitations.

(2) There may be malfunctions associated with the APS that have not been identified in either the staff's deterministic or probabilistic risk analyses. Pressurizer nozzle fatigue is one example of a limitation of the APS that

may restrict the use of this system, and there may be others that are unidentified. The staff believes that the PORV would provide another means of depressurizing the RCS. Although the CE plants without PORVs meet the licensing basis considerations, assuming the single failures in the APS are corrected, the PORV could provide a redundant and diverse means of depressurization for SGTR and SBLOCA scenarios.

(3) The PORV, if suitably sized, would provide a redundant and diverse means of core decay heat removal. Calculations by CE and ANL have shown that feed and bleed is a viable means of core cooling for TLOFW scenarios.

(4) As an additional improvement in plant safety, an automatically actuated PORV may avoid pressurizer safety valve actuation in situations in which the steam dump system does not function properly after loss of loads or when the ultimate heat sink is lost altogether. However, the possibility of a PORV LOCA must be considered in both PRAs and in the assessments of possible costs resulting from inadvertent or accidental PORV openings. The staff's initial estimate of the contribution to the severe core damage frequency from a PORV LOCA is very small, provided the PORV block valves are operated by direct current. If CE believes the contribution is greater, CE could reduce this contribution by considering variations in PORV opening logic or the use of automatic PORV block valves.

Overall, although the staff recognizes that a number of multiple-failure accident scenarios can be mitigated using the existing systems, the mitigation systems themselves have limitations that may limit or even totally defeat their mitigation capabilities. A properly sized, reliably powered PORV would, overall, provide a net addition to plant safety. A PORV would provide a redundant and diverse means of controlling RCS pressure for any accident scenario in which primary pressure is important.

4.4 Probabilistic Risk and Value Impact Assessments

The staff recognizes that the value of a PORV must be compared to the potential costs. This can be done using engineering judgment and deterministic calculations. The conclusions listed in the sections above come from these assessments.

The staff also used probabilistic and value/impact assessments to measure the potential benefits of a PORV. The following conclusions apply to those assessments:

(1) Probabilistic risk assessments performed by the staff, which incorporated the potential for common-mode malfunctions, determined that the overall core melt probability for SONGS-2 and -3 would be reduced by about 2×10^{-5} per reactor year as a result of the installation of properly sized, powered, and configured PORVs. This reduction in core-melt probability comes from the TLOFW accidents in which the condensate system fails and from the ATWS accidents on the 3410-MWt class CE plants.

(2) The staff believes that the probability of an SBLOCA as a result of a stuck-open PORV can be minimized by properly designing and powering the PORV and its block valve. It is the staff's judgment that the probability is approximately the same as the probability of a pressurizer safety valve LOCA, which cannot be isolated using block valves.

(3) The staff's PRA was limited to the benefits obtained in reduced core-melt frequency. No attempt was made to examine the potential risk reduction associated with the consequences of core melt accidents already in progress. For example, system depressurization using a PORV prior to core melt during a severe accident could reduce the consequences of the event.

(4) A staff consultant, Burns & Roe, determined that the installation of a supplementary depressurization system (a PORV) would cost from $2.5 million for a new, unoperated plant to $4.3 million for an operating plant. However, the testing program that must accompany a PORV installation could extend the normal outage by 2 to 3 days, which could add an additional $3 million for the cost of replacement power.

(5) There is good agreement between PORV installation cost estimates of the staff consultant and the CE owners group, with the exception of the owners group estimate for replacement power. The owners group estimate for this cost is considered to be overly conservative.

(6) For the installation of a PORV on a plant that has operated, total personnel exposure during a PORV installation is estimated to be approximately 400 man-rem.

(7) The staff performed a value/impact analysis for installing PORVs based on the change in core-melt probability, averted public risk, and resulting occupational radiological exposure impacts. The evaluation shows that a positive, but small, value/impact ratio would result from the installation of PORVs on the current CE system design.

(8) Procedures for aggressive cooldown of the RCS for SBLOCAs with failure of the HPI systems are cost effective, in the staff's judgment; they lead to a benefit of $500,00 to $1,000,000 from averted core melts. Similarly, the staff finds that procedures for depressurizing the steam generators and using the condensate pumps to supply feedwater to the steam generators for accident sequences in which main feedwater and auxiliary feedwater are lost are cost effective. The benefit from averted core melts for plants without PORVs, is about $2 to $5 million. The staff is incorporating this into the ongoing I.C.1 program.

The PRA showed that a PORV could reduce the core-melt probability by an appreciable amount. The accident scenarios whose core-melt probabilities were reduced are the TLOFW and ATWS accidents. However, an assessment of the overall value/impact of PORVs installation showed only a small value/impact ratio. This assessment, which considered all costs and man-rem averted and incurred, indicated that PORV installation would not be justified. However, the assessment could not quantify all the values, including such operational aspects as increased flexibility in avoiding significant offsite radiological releases in accidents not leading to core melt. Similarly, the value/impact analyses could not quantify the benefits associated with the extra flexibility afforded to the operator in managing other less severe accidents in which the normal depressurization means fail.

4.5 Conclusions

The overall results of the staff evaluation conclude that there is a net benefit in adding PORVs to the current CE plants without them. Although the quantitative portions of the evaluation (cost-benefit, regulatory requirements) do not support this conclusion, other factors (beyond design-basis events, imponderable events, engineering judgment, large uncertainties on PRA results) that entered into the decision-making, when combined with the quantitative evaluation, led to this conclusion.

The NRC is also in the process of resolving the more comprehensive generic issue, USI A-45, Decay Heat Removal Requirements. Because part of the benefit of the PORVs was predicated on their ability to provide an alternate decay heat removal path (feed and bleed), any improvements in decay heat removal capability that might be promulgated as a result of the USI A-45 assessment could reduce the net benefit of PORVs. Therefore, the staff concludes that the decision regarding PORVs for these CE plants should be deferred and incorporated into the technical resolution of USI A-45. Finally, it should be noted that the events for which PORVs could prove to be of benefit are of low probability, and the staff is aware of no immediate safety concerns associated with incorporating the PORV decision into the A-45 program.

APPENDIX A

CHRONOLOGY OF ISSUES AND EVENTS
ASSOCIATED WITH THE STUDY OF
CE PLANTS WITHOUT PORVS

December 15, 1981	ACRS letter to NRC Chairman Palladino expressing concern regarding CE plants without PORVs.
January 25, 1982	Ginna SGTR accident.
January 29, 1982	RES issued, cursory PRA for CE plants without PORVs.
February 8, 1982	Staff requested that CE address the adequacy of design without PORVs and comment on RES PRA.
March 4, 1982	CE responded to February 2, 1982, staff letter.
March 16, 1982	Staff met with ACRS subcommittee on status of CE PORV issue.
September 6-9, 1982	SONGS-2 Natural Circulation Tests (first phase).
December 6, 1982	Staff met with representatives of SONGS-2 on viability of installing PORVs on SONGS.
January 12, 1983	Staff met with contractors and CE owners group on status of PORV efforts.
January 27, 1983	CE and NRC staff met with ACRS subcommittee on status of PORV issue.
March 22, 1983	Staff letter to CE owners group forwarding questions/ comments from January 12 meeting.
April 4, 1983	Staff briefed Commission on status of PORV issue.
June 30, 1983	CESSAR, Waterford, and SONGS-2 and -3 responses to staff questions received.
July 7-8, 1983	Staff met with CE owners group in Windsor, CT to discuss response to questions.
August 24, 1983	Staff met with ACRS subcommittee on conclusions and recommendations regarding need for PORV on current CE plants.

October 4, 1983	Staff met with ACRS subcommittee on staff evaluation of the CE PORV issue.
October 13-15,	Staff met with ACRS on staff evaluation of the CE PORV issue.
February 3, 1984	Staff met with CRGR on staff evaluation of the CE PORV issue.
April 3, 1984	Staff met with Commissioners on staff evaluation of the CE PORV issue.

APPENDIX B

DETAILED STAFF EVALUATION OF RESPONSES TO 14 QUESTIONS REGARDING THE NEED FOR RAPID DEPRESSURIZATION CAPABILITY FOR CE PLANTS

CONTENTS

CONTENTS (Continued)

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APPENDIX B

DETAILED STAFF EVALUATION OF RESPONSES TO 14 QUESTIONS REGARDING THE NEED FOR RAPID DEPRESSURIZATION CAPABILITY FOR CE PLANTS

INTRODUCTION

This appendix contains a discussion and the staff's evaluation of the applicant's responses to 14 staff questions regarding the need for rapid depressurization capability for Combustion Engineering (CE) plants (Tedesco, March 26, 1982). Because the questions involved technical aspects associated with a variety of review branches of the Office of Nuclear Reactor Regulation (NRR), a matrix was developed to ensure that the staff review of each response was conducted by the appropriate branches. This matrix is shown as Table 1.

Questions and responses are presented as numbered in Table 1.

Table 1 CE plant PORV study: branch review responsibilities*

Task	RSB	ASB	CEB	RRAB	MEB	GIB	PSRB	EQB	SPEB	AEB
I. Evaluation of CE, SONGS, and Waterford responses to 14 staff questions										
1. Auxiliary pressurizer spray	P		X							X
2. Limiting plant scrams	P			X						
3. ATWS	X			P		X				
4. PTS	P					X				
5. Low probability events	P	X		X	X	X				X
6. Low pressure feed	X	P					X			
7. SG tube corrosion			P		X					
8. LOFW, feed and bleed	X	X		P						
9. Risk due to SGTRs				P	X		X			X
10. PORV LOCA risk				P						
11. Net risk gain/loss with PORVs				P		X				
12. PORV installation costs					X	P		X	X	
13. SG tube structural integrity					P					
14. Preheater section tube vibration					P					
II. Evaluation of ANL report	P			X		X				X
III. Evaluation of SNL & B&R reports	X	X		X	X	P	X	X	X	

P = Primary Review Branch; X = Secondary Review Branch.
*See Acronyms list at the beginning of this appendix for definitions of acronyms used in this table.

1 QUESTION 1: Auxiliary Pressurizer Spray

This question asks each applicant to fully describe the auxiliary pressurizer spray (APS) system and to assess its depressurization capabilities under a variety of conditions, including the design-basis steam generator tube rupture (SGTR). The SGTR requires early operator intervention to rapidly depressurize the reactor coolant system (RCS) using the APS. The staff also asked for an assessment of the thermal stresses of the pressurizer spray nozzle.

1.1 CE Owners Group Response

In response to this question, the CE owners group (CEOG) assessed the performance capabilities of the APS and reported the results in "Depressurization and Decay Heat Removal, Response to NRC Questions" (CEN-239). This document was forwarded to the staff in the following letters:

CE-80 (Scherer, June 29, 1983)
SONGS-2,-3 (Baskin, June 22, 1983)
Waterford 3 (Drummond, June 29, 1983)
Palo Verde 1, 2, 3 (Van Brunt, July 28, 1983)

In response to a staff question, CEN-239 contains a description of each plant's APS system, an evaluation of the depressurization capabilities (based on calculations performed by CEFLASH) under a variety of conditions including the SGTR, and an assessment of the thermal stresses in the pressurizer spray nozzle as a result of APS.

1.2 Staff Evaluation and Conclusions

1.2.1 APS Design

During normal plant operation, pressurizer spray flow is provided via the main spray valves. For conditions in which the reactor coolant pumps (RCPs) are not available, main spray cannot be used to control system pressure. The APS provides a means to reduce RCS pressure should main spray not be available. For CE plants without power-operated relief valves (PORVs), the APS system is available for depressurization. The system has been characterized as safety-related. This system, which is a part of the chemical and volume control system (CVCS), consists of two safety-related auxiliary spray valves in parallel and their associated piping. The redundant auxiliary spray valves, divert charging flow at the outlet of the regenerative heat exchanger through the piping downstream of the main pressurizer spray valves into the pressurizer spray nozzle at the pressurizer.

The configuration of the APS for San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 is shown in Figures 1 and 2. The APS flow is initiated from the control room by opening the auxiliary spray valves (2HV-9201), ensuring that the two main spray valves are closed, and closing the two loop charging valves (2HV-9202 and 2HV-9203). For SONGS-2 and 3, the charging pumps are automatically started after they are automatically loaded to the diesels following a loss of offsite power. If either the auxiliary spray valve (2HV-9201) fails to open or one of the loop charging valve fails to close, a bypass line that has been provided with a manually operated auxiliary spray valve (130-C-334) could be

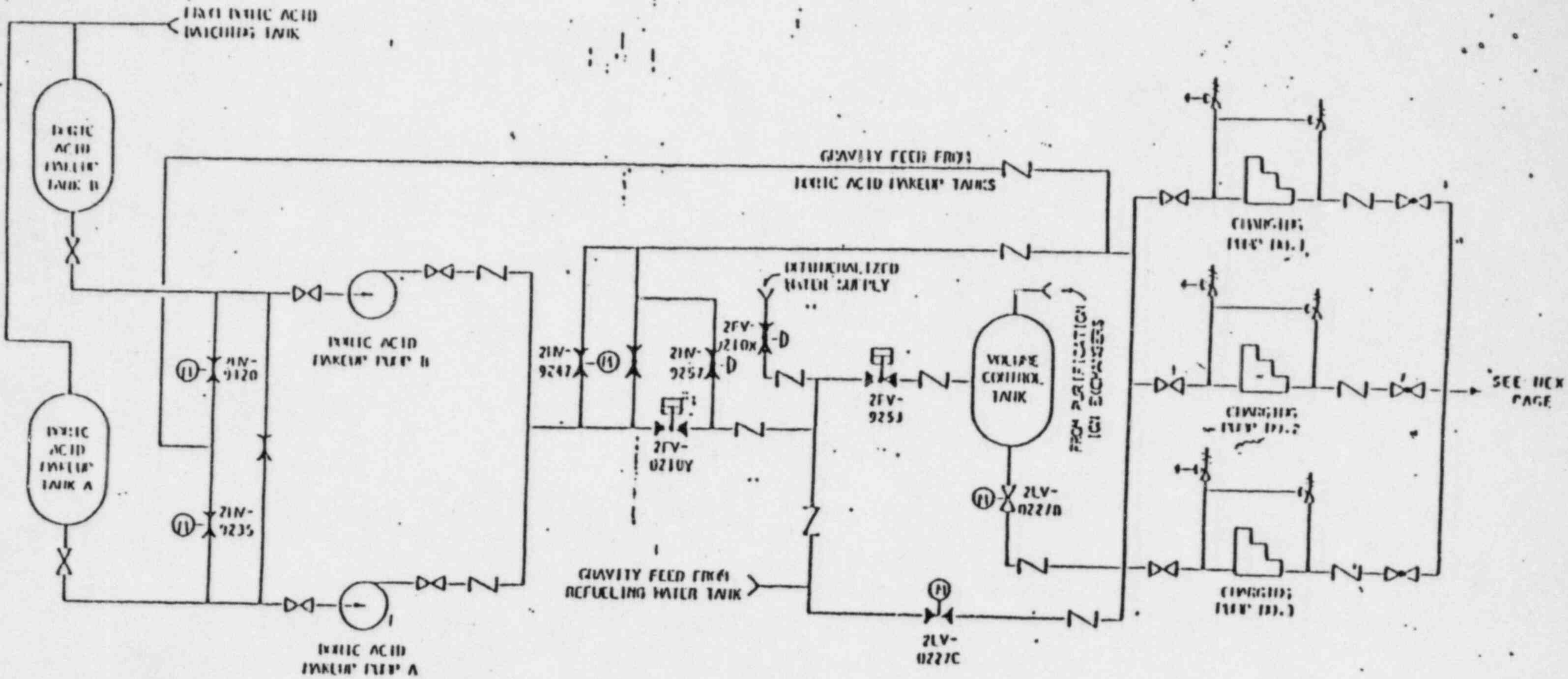

Figure 1 Simplified schematic of SONGS CVCS showing auxiliary spray portion and sources of borated water, left hand portion
Source: CEN-239, Figure 2.1-2

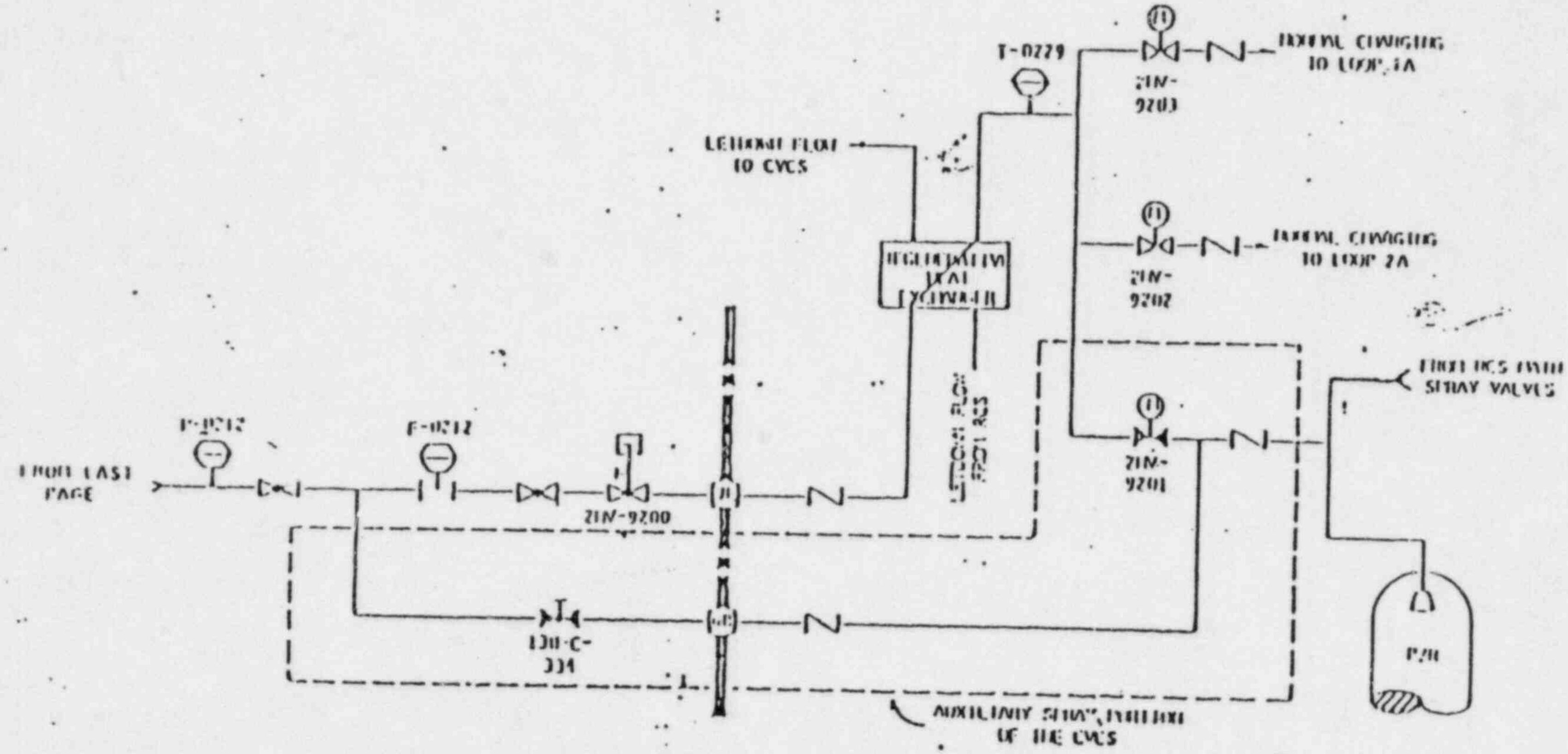

Figure 2 Simplified schematic of SONGS CVCS showing auxiliary spray portion and sources of borated water, right hand portion
Source: CEN-239, Figure 2.1-2

initiated from outside containment. One potential vulnerability of this APS design has been identified: failure of one of the two main spray valves to close could cause insufficient APS flow to the pressurizer. This staff concern was not addressed in the CEOG response to Staff Question No. 1. However, in the meeting of July 7, 1983, with CEOG (Liang, July 21, 1983), Southern California Edison (SCE) indicated that a system modification is being considered wherein a check valve would be installed at the main spray discharge line to prevent back flow of the APS flow into main spray lines. This system modification should resolve the staff concern noted above.

The configuration of the APS for Waterford 3 is shown in Figures 3 and 4. The APS flow is initiated from the control room by opening one of the redundant auxiliary spray valves (CH-517 or ICH-E2505B) and closing the two loop charging valves (CH-518 and CH-519). A check valve has been provided in the main spray piping to prevent APS flow back into the main spray line in case of a single active failure of the main spray valve. Charging pumps A and B are automatically started after they are automatically loaded to the diesels. The two loop charging valves that must be closed to prevent flow into the RCS loops during auxiliary spray operations are Class 1E solenoid valves that are designed to fail in the closed position upon loss of motive power. The control system for these valves is Class 1E and is controlled by the operator from the control room. If one of the valves failed to the open position, the result would be insufficient charging flow to the pressurizer. In the judgment of the staff, the current design is such that the loop charging valves could fail in the open position as a result of a control system failure and thus cause insufficient APS flow toward the pressurizer.

The configuration of the APS for CE System 80 plants (Palo Verde 1, 2, and 3, and WPPSS 3) is shown in Figures 5 and 6. The APS flow is initiated from the control room by opening one of the redundant auxiliary spray valves (CH-203 or CH-205) and closing the loop charging valve (CH-240). A check valve has been provided in the main spray piping to prevent APS flow back into the main spray line in case of a single active failure of the main spray valve. The charging pumps are manually initiated after they are automatically loaded to the diesels. The loop charging valve (CH-240), which must be fully closed to get full auxiliary spray flow, is air operated, with a Class 1E solenoid. The valve is designed to fail closed on loss of air and loss of power to the solenoid. However, as in the Waterford 3 design, if the loop charging valve (CH-240) failed to a open position, insufficient spray flow would result. In the judgment of the staff, the current design is such that the loop charging valve could fail open and thus cause insufficient APS flow toward the pressurizer.

During the July 7-8 meeting with the CE owner group, the staff learned that in the CE-80 charging systems, flow to the RCP seals is controlled via control-grade valves outside containment. Should there be a malfunction of these valves or the associated control systems during situations where APS flow is needed, some charging flow would be directed from the APS system. In the judgment of the staff the reduction in APS flow in this case would not be as significant as it would be in the case where the loop charging valves failed to close. Nonetheless, this is a case where performance of the APS depends on the functioning of a control-grade system. The staff notes that malfunctions in the seal injection portion of the charging system can be corrected by manual valve operation outside containment. However, the flow to the RCP seals is less than the flow to the loops should the loop charging valves fully open, and the impact

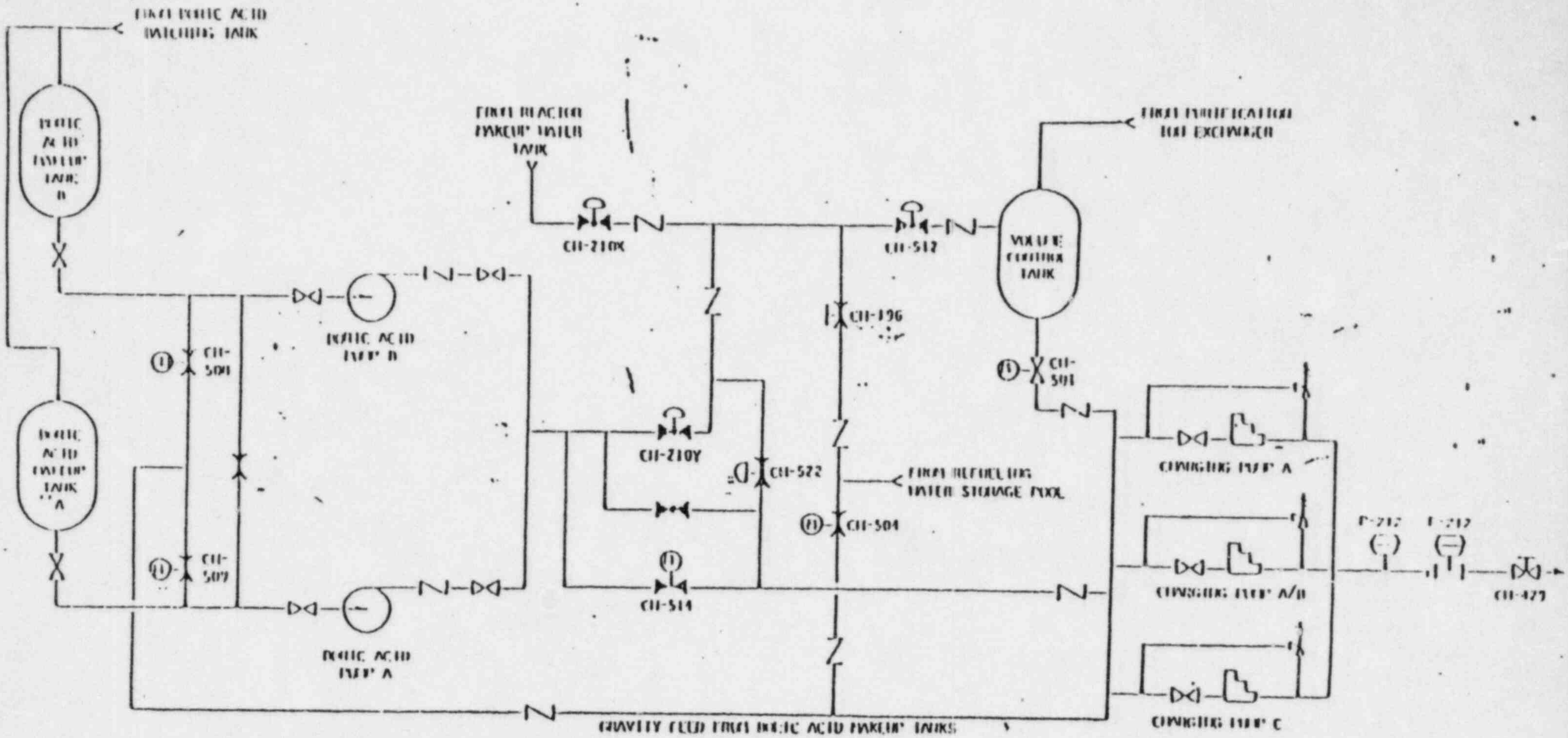

Figure 3 Simplified schematic of Waterford CVCS showing auxiliary spray portion and sources of borated water, left hand portion
Source: CEN-239, Figure 2.1-3

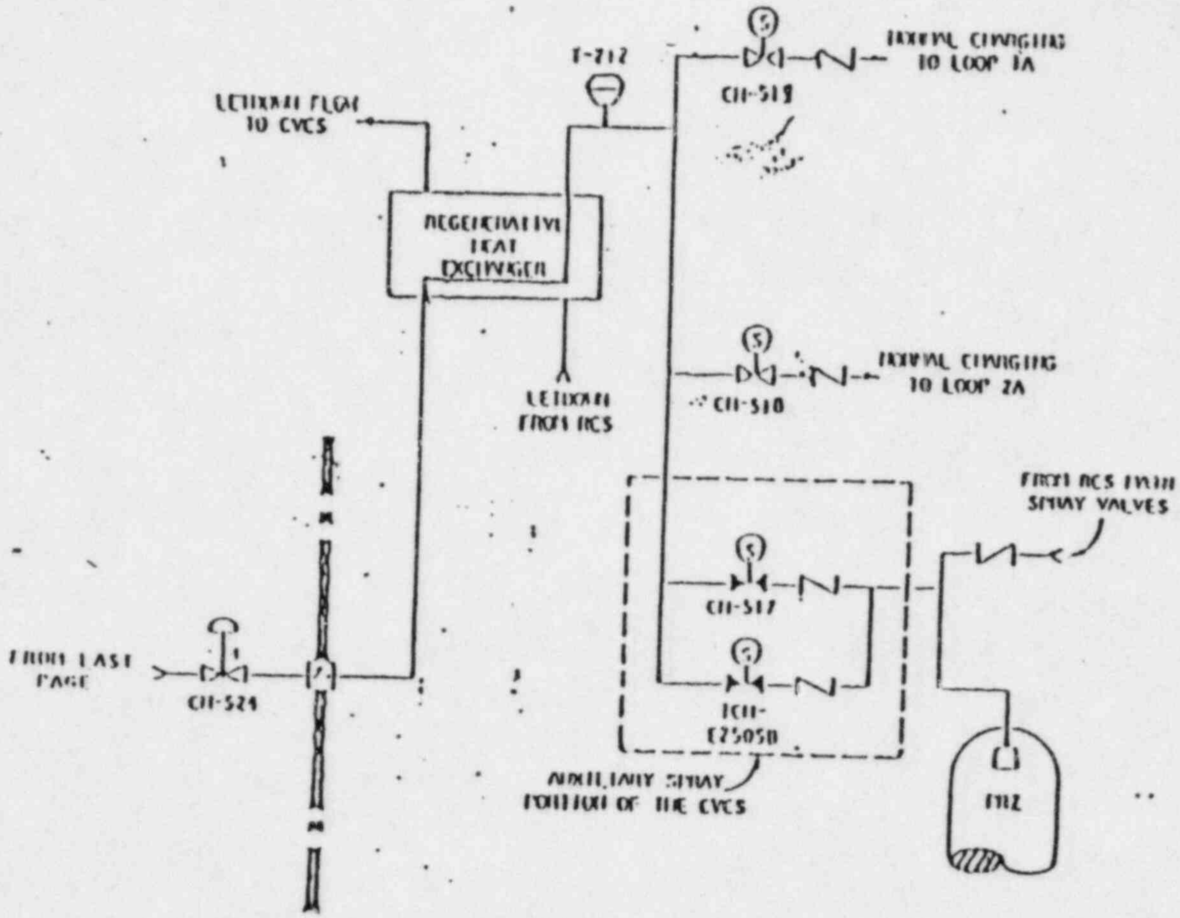

Figure 4 Simplified schematic of Waterford CVCS showing auxiliary spray portion and sources of borated water, right hand portion
Source: CEN-239, Figure 2.1-3

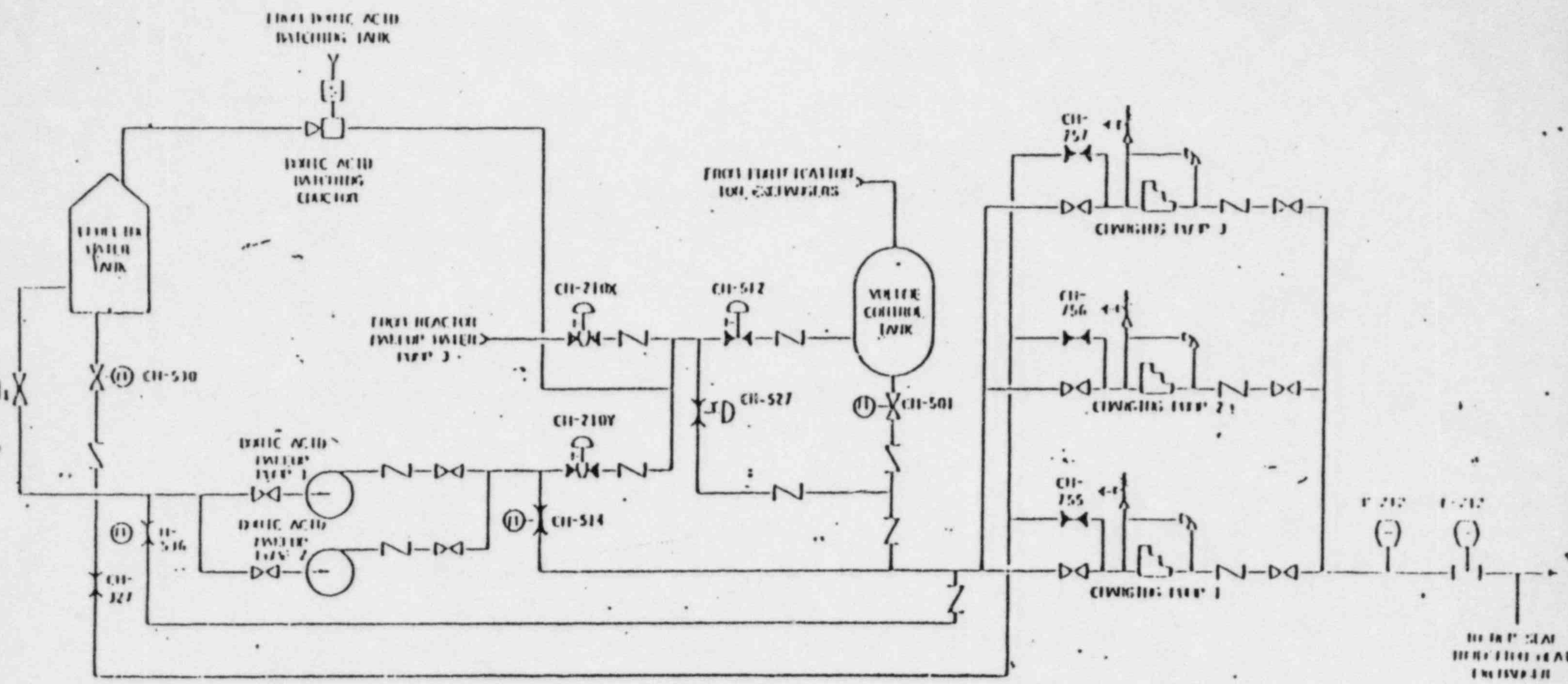

Figure 5 Simplified schematic of Palo Verde CVCS showing auxiliary spray portion and sources of borated water, left hand portion
Source: CEN-239, Figure 2.1-4

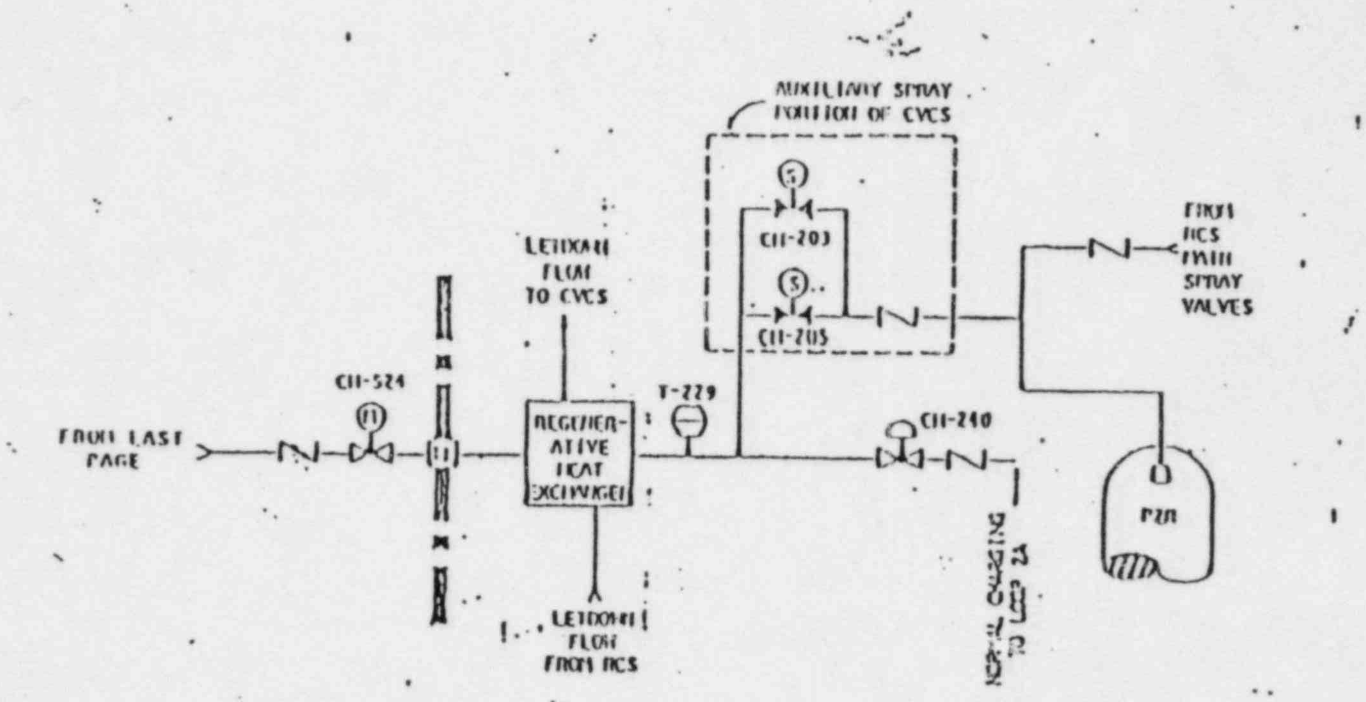

Figure 6 Simplified schematic of Palo Verde CVCS showing auxiliary spray portion and sources of borated water, right hand portion
Source: CEN-239, Figure 2.1-4

on APS performance would be less as a result of malfunctions in the RCP injection line. The staff has requested the applicant associated with CE System 80 design to address the effects of this potential single failure in the APS system.

The staff notes that for all plants considered (SONGS-2 and -3, Waterford 3, and Palo Verde 1, 2, and 3) there are no Technical Specifications associated with the APS despite its apparent importance in the mitigation of design-basis accidents and its safety classification. There are no Technical Specifications regarding the operability of the system overall, the associated limiting conditions for operation (LCOs), or surveillance requirements. The staff notes that there are Technical Specifications for the charging pumps, but these specifications are associated with the boron injection requirements, and there are no discussions or requirements for the charging pumps with respect to APS system function.

Pending the responses to staff questions regarding the necessity for the APS in mitigating SGTRs and the potential susceptibility to single failures, Technical Specifications may be developed and implemented. These Technical Specifications would be generic, but would probably have to be made plant-specific in some respects because of the slight differences in plant design.

In summary, the Waterford 3, Palo Verde 1, 2 and 3, and CE-80 APS systems have the potential for single failures that may significantly limit spray capability. These failures are associated with loop charging valves. Further, the CE-80 plants' APS systems rely on the isolation of charging flow to the RCP seals, which is accomplished using control-grade valves. The staff has requested the applicants to address these single-failure vulnerabilities. Further, the APS systems for all plants do not have associated Technical Specifications to ensure proper equipment operability, availability, and surveillance; pending the responses to the staff questions Technical Specifications may be necessary. With the exception of these items, the APS systems meet the staff's safety-related standards.

1.2.2 APS Performance

1.2.2.1 Steady-State RCS Conditions

The depressurization capability of the APS depends on a variety of factors. Assuming a steady-state subcooled RCS, in which the reactor vessel upper head (RVUH) is relatively far from saturation, the depressurization ability of the APS depends on (1) APS flow, (2) APS temperature, (3) pressurizer steam space temperature, and (4) pressurizer steam volume. CE evaluated the APS depressurization rates considering variations in the first two of these factors, and determined the effect on depressurization rate should there be a large and expanding RVUH. (This latter condition is addressed in Section 1.2.2.2 below.) CE did not consider the effect of initial pressurizer steam volume or temperature; however, the staff believes that the main factors affecting APS depressurization rate are APS flow rate, APS fluid temperature, and the effects of RVUH steam void expansion.

The CE analysis was performed for both the 3800-MWt and 3410-MWt classes of plants, because the pressurizer steam volume and other RCS parameters differ somewhat between these plants. The results of the CE analysis--shown in

Table 2 and in Figures 2.1-6, 2.1-7, 2.1-9 and 2.1-10 of CEN 239--show that the depressurization rates under a steady-state RCS temperature and volume condition vary from 30 psi/min to 148 psi/min for the 3410-MWt class plants and from 27 psi/min to 126 psi/min for the 3800-MWt plants. The depressurization rates are somewhat lower for the 3800-MWt plants because of the somewhat larger steam space in the 3800-MWt pressurizer.

These results were compared to thermal-hydraulic calculations performed for the staff by Argonne National Laboratory and reported in ANL/LWR/NRC-83-7 (Argonne, July 1983), and to depressurization rates observed during natural circulation tests at SONGS-2 on September 6 through 9, 1982 (Liang, September 28, 1982).

The ANL calculations, which were performed to investigate the system performance and offsite consequences during a variety of SGTR scenarios, predicted depressurization at a rate of approximately 120 psi/min for the 3800-MWt plant (Figure 4.1.1.1 of ANL/LWR/NRC-83-7), for the same set of conditions used in CEN-239 for the prediction of 126 psi/min. ANL did not calculate depressurization rates for the other conditions assumed in the CEN-239 report.

During the natural circulation tests at SONGS-2 in September 1982, Test A2 was performed to determine the pressurizer heat loss with the reactor critical at low power, with the RCS in a natural circulation mode at near normal operating temperature and pressure, and with both steam generators removing decay heat through their atmospheric dump valves (ADVs). At the completion of this test, one charging pump was started and auxiliary spray flow, heated by letdown flow through the regenerative heat exchanger, was initiated. The staff observed a depressurization rate of about 20 psi/min, which is comparable to the rate calculated by CE for 3410-MWt class plants under this condition.

For comparison purposes, CE also determined the depressurization rates for a range of PORV sizes, because the staff asked whether a PORV would provide more effective mitigation of events both within and beyond the design basis. These depressurization rates for three valve flow areas are presented in Table 2.

Table 2 Depressurization rates for three valve flow areas*

Valve size	Plant	Depressurization rate
0.0021 ft^2	Palo Verde (vent system)	54 psi/min
0.0095 ft^2	Calvert Cliffs PORV	270 psi/min
0.0341 ft^2	CEN-239 feed and bleed PORV	822 psi/min

*Reproduced from CEN-239, Table 2.1-1.

In summary, the staff concludes that the CEN-239 depressurization rates predicted for the 3410- and 3800-MWt class reactors, under conditions in which there are an adequate steam void volume and a minimal pressurizer insurge rate, appear to be reasonable, and are sufficient to control system depressurization during normal nontransient conditions.

1.2.2.2 Transient RCS Conditions

As noted earlier, the APS is effective as a means of system depressurization if a steam space exists in the pressurizer and if the rate of pressurizer insurge is not so large that it overcomes the depressurization caused by APS-induced steam condensation. The steam space could be lost by a number of mechanisms: (1) RVUH steam void expansion, caused by RCS depressurization, displacing RCS hot-leg fluid into the pressurizer; (2) filling the pressurizer with APS fluid; or (3) filling the RCS, and hence the pressurizer, with safety injection fluid. With respect to the pressurizer insurge rate effect on APS depressurization rate, CEN-239 calculations for SGTR determined (Case 4, page 41, CEN-239, Figures 2.1-44 to 47) that with a pressurizer insurge rate of approximately 0.1%/sec (about 20 ft^3/sec) and an APS rate of 88 gpm, the RCS depressurization rate is about 20 psi/min. The steady-state depressurization analysis, discussed above and shown in Table 2, predicted an initial depressurizaton rate (3800-MWt plant without letdown and 88 gpm APS flow) of about 87 psi/min.

The ANL calculations (Argonne, July 1983) showed the effect of pressurizer insurge more clearly. The CE calculations seem to show that the depressurization rate is constant while the insurge is taking place. That is, the pressure linearly drops at 20 psi/min while there is a 50% increase (from about 30% to 80%) in level or about 900 ft^3. The linearity of the depressurization is questionable. The ANL calculations show a more reasonable depressurization. Figures 4.1.4-2 and -3 of ANL/LWR/NRC-83-7 show the depressurization rate dropping from an initial value of about 127.8 psi/min while the pressurizer is almost empty, to about 18 psi/min when the pressurizer is nearly full.

Both the CE and ANL calculations do show the reduction in depressurization rate as a result pressurizer insurge. Therefore, for the APS to remain effective in depressurizing the RCS, not only must there be an adequate steam void in the pressurizer, but the pressurizer insurge cannot be excessive.

The importance of the insurge rate on APS performance was demonstrated in the loss of fluid test (LOFT) experiments L9-1 and LP-FW-1. Both experiments were loss of feedwater (LOFW) events in which the steam generators were steamed without feedwater flow, with the reactor critical (EG&G, September 1983, and NRC OELD-LOFT-T-3104). When the steam generator inventory was reduced to a point where the energy removed did not equal the reactor power, the RCS began to heatup and pressure began to increase (see Figure 1 of EG&G, September 1983 and Figures 1, 4, and 22 of NRC OELD-LOFT-T-3104). The pressurizer spray was able to control system pressure until the insurge rate, because of the RCS heatup rate, exceeded the spray depressurization capability and pressure continued to rise to the reactor trip point.

In summary, during transient conditions where there might be excessive pressurizer insurge or if the steam void is lost, the APS performance is significantly reduced. This limitation has been both observed and calculated. The staff notes that the APS is not intended as a means of removing energy from the RCS, which these two experiments demonstrated. As the RCS heats up as a result of the loss of heat sink, the combination of pressurizer level and insurge rate will reach a point where depressurization is no longer possible. Under such circumstances, pressure would rise to the pressurizer safety valve set-points, and decay heat would be removed through that flowpath.

1.2.2.3 Design-Basis SGTR

The capability of the APS to depressurize the RCS following a design-basis SGTR is important because the SGTR accident is the only design-basis accident in which rapid, manually controlled RCS depressurization is mandatory for mitigation. The use of the APS in this event, rather than the PORV, was examined by both CE and by the staff. The CE evaluation, presented in CEN-239, compared the depressurization rates of the APS to an assumed PORV during a design-basis SGTR. Five cases were evaluated for the 3800-MWt reactor, as shown in Table 3.

Table 3 Single SGTR cases analyzed by CE

Case	Comments
1	Base case, no APS or PORV depressurization
2	88-gpm APS at 15 min, 30°F subcooling limit
3	PORV at 15 min, 30°F subcooling limit
4	Large RVUH void following continuous 88-gpm APS flow
5	Large RVUH void following PORV opening

In general, these calculations showed that although the system performance using a PORV was the same as with an APS system, the PORV, when open, provided a more rapid system depressurization. However, as CEN-239 points out, the depressurization is limited by the subcooling limit and not by the ability of the PORV or APS. As long as there is a steam void of adequate volume in the pressurizer and there is no significant insurge (as could occur if the heat transfer to the steam generators were lost) CE asserts that the APS and PORV performance characteristics are essentially the same for the design-basis SGTR.

This assertion cannot be evaluated without an appraisal of the offsite consequences using both techniques of depressurization. Because the CE report did not assess radiological consequences, the staff used the thermal-hydraulic calculations performed by ANL to assess the offsite doses for the SGTR accidents using the two techniques of depressurization (APS or PORV).

ANL performed SGTR analyses to examine the APS and PORV capabilities under a variety of single failures and operator errors. It should be noted that the Standard Review Plan section associated with the SGTR (SRP Section 15.6.3, NUREG-0800) does not specify the necessity for assuming any single failures beyond the loss of offsite power or operator errors. Therefore, some of the analyses performed by ANL are, strictly speaking, beyond the SRP guidance.

The analyses by ANL are described in ANL/LWR/NRC-83-7 and are listed in Table 4.

Table 4 Single SGTR cases analyzed by ANL

Case	Comments
1	Single SGTR with APS for depressurization
2	Single SGTR with PORV for depressurization
3	Single SGTR with APS, stuck-open ADV on the ruptured steam generator for 20 min
4	Single SGTR with continuous APS (operator error), continued HPSI flow, and APS flow stopped after water solid
4a	Single SGTR with continuous APS (operator error) and APS and HPSI flows stopped after water solid
5	Single SGTR with continuous APS (operator error)
6	Single SGTR with ADV stuck open on ruptured steam generator for the duration of the case

The staff used the primary and secondary system parameters predicted by ANL from the calculations listed above to determine the offsite radiological consequences.

The SGTRs were assumed to be double-ended guillotine breaks of a single tube; this SGTR accident results in a reactor scram and turbine trip. The turbine trip is assumed to cause a loss of offsite power, which makes the condenser unavailable for mitigating the releases. The primary system activity is transported to the secondary system at a rate that is a function of the primary and secondary system pressures and the tube diameter. Because the primary system is at a higher pressure and temperature than the steam generator, some of the primary fluid leaked to the generator is estimated to flash to steam. The staff assumed that all the activity in the flashed primary coolant is released to the environment via either the open relief valves or the ADVs.

The primary coolant fluid that does not flash was assumed to mix with the steam generator water. The iodine in the steam generator was assumed to be released at a rate proportional to the partition coefficient identified in SRP Section 15.6.3.

Two estimates of the potential offsite consequences were calculated for ANL Cases 1 and 2. One estimate assumed an initial coolant activity of 1.0 μCi/gm dose-equivalent iodine-131 (DEI-131) and an event-generated iodine spike. The other estimate assumed that a pre-accident iodine spike had occured and raised the primary system activity to the maximum value permitted by the Technical Specifications (60 _Ci/gram DEI-131). The second estimate did not include any additional iodine spiking. The release pathways for both estimates were the same. A summary table of assumptions used in the staff's evaluation is provided in Table 5.

Table 5 Staff assumptions used in evaluating the radiological consequences following postulated SGTR accidents

Case	Comments
1	Initial primary coolant system activity, 1.0 μCi/gram dose equivalent I-131 (DEI-131)
2	Initial secondary coolant system activity, 0.1 μCi/gram DEI-131
3	Iodine spiking factor of 500 times the normal release rate
4	Iodine partition coefficient of 100 between secondary steam and secondary water in the steam generators
5	Atmospheric dispersion factor for the exclusion are a boundary of $1.08X10^{-3}$ sec/m^3 (3800-MWt class plant)
6	Flash fraction for primary to secondary leakage in the damaged steam generator determined by pressure and temperature conditions of the primary and secondary system; all activity in the flashed fluid released directly to the environment
7	Primary-to-secondary leakage from the unaffected steam generator of 1 gpm for the duration of the accident
8	No flashing of the primary system leakage in the unaffected steam generator
9	For the case of the pre-accident iodine spike, an initial primary system activity of 60 _Ci/gram DEI-131; no additional iodine spiking for the pre-accident iodine spike event

The staff's evaluation of ANL Cases 1 and 2 indicated that the radiological consequences following the design-basis SGTR are essentially the same for the mitigation of the accident using either the APS or the PORV method. Use of either method would not result in radiological consequences that would exceed the acceptance criteria described in SRP Section 15.6.3.

ANL evaluated Case 3 to determine the significance of a stuck-open ADV on the ruptured steam generator. CE emergency procedure guidelines (EPGs), described in CEN-152, Revision 1 (CE, November 1982), specify that if offsite power is lost following the design-basis SGTR, the operator is to use the ADVs on both steam generators to cool the RCS to below 565°F. This method of SGTR mitigation is different from other PWR techniques because it results in early continuous releases from the damaged steam generator. Should the ADV stick open and the operator not recognize it, the offsite consequences could be significant. The capability of the APS under this situation was examined.

Case 6 was evaluat. to investigate the same equipment malfunction, a stuck-open ADV, followed by an operator error in which the operator did not recognize the continuous release and take the proper mitigative action to isolate the stuck-open ADV by closing its upstream block valve. Here again, the capabilities of the APS to mitigate the event were studied.

In Case 3, ANL evaluated the primary and secondary system responses for an APS system assuming that an ADV on the affected steam generator was stuck in the 30% open position for 20 minutes. It was assumed that after 20 minutes, the operator would have identified the malfunction and have taken action to close the ADV. The failure of the ADV for a short duration lowers the pressure in the affected steam generator. This results in continued primary-to-secondary leakage after the affected ADV has been closed, and the primary-to-secondary leakage cannot be readily terminated. The above circumstance creates a larger primary-to-secondary leakage, a larger primary fluid flash fraction, and a substantially larger ADV flow than the design-basis SGTR.

Another problem area with Case 3 is the ability to control the water level in the affected steam generator. In Case 3, ANL assumed that the auxiliary feedwater to the affected steam generator would be isolated as part of the steam generator isolation procedure. This assumption permits the level in the steam generator to drop below the top of the tube bundle during some of the period that the ADV is stuck open. Consistent with previous staff practice, the staff conservatively assumed that all radioactivity in the primary-to-secondary leakage to the affected steam generator during the tube uncovery period and before ADV isolation is released directly to the environment.

The impact of the assumption of iodine transport during the tube uncovery period is that the estimated radiological consequences are significantly larger than those calculated for Cases 1 and 2. The estimate of the radiological consequences of an SGTR with an accident-generated iodine spike would be less than the guideline values specified in Title 10 of the Code of Federal Regulations Part 100 (10 CFR 100). However, the more conservative estimate using the pre-accident iodine spike would result in potential radiological consequences that slightly exceed the guideline values of 10 CFR 100.

ANL evaluated Case 6 to determine the effects of an equipment malfunction, followed by an operator not recognizing the malfunction. ANL evaluated the primary and secondary system response for an APS system assuming that an ADV on the affected steam generator failed in the 100% open position for the accident duration. The inability to maintain pressure in the secondary system results in a larger primary-to-secondary system pressure differential and a significantly larger primary-to-secondary flow through the ruptured tube. The stuck-open ADV permits a blowdown of the affected steam generator to the atmosphere and hence all the activity in the primary-to-secondary leakage is assumed to be released directly to the environment.

The larger tube leakage, in combination with the assumed inability to isolate the steam releases from the affected steam generator, results in greater radiological consequences than those predicted for Case 3 and significantly greater than those from a design-basis SGTR (Cases 1 or 2). Because the ADV release rate and affected steam generator pressure were controlled for the multiple SGTR case described in Section 5.2 below. The potential radiological consequences for Case 6 are greater than those predicted for the multiple SGTR. In both staff estimates, the potential radiological consequences exceeded the guideline values of 10 CFR 100.

With respect to the capability of the APS or an assumed PORV to mitigate either of these accidents, the staff notes that continued ADV flow (for 20 minutes in Case 3 or for the accident duration in Case 6) aids system depressurization by the contraction caused by system cooldown. Table 6 summarizes ANL Cases 1, 3, and 6 with respect to depressurization times and APS flowrates.

Table 6 SGTR depressurization times with APS

Case	Description	Time to reach 1200 psig	Integrated APS flow	RCS temp (T_{AVE})
1	Base case, APS	4700 sec	2750 lb_m	535°F
3	ADV stuck 30% open (20 min)	3800 sec	4600 lb_m	532°F
6	ADV stuck 100% open (duration)	3600 sec	5500 lb_m	510°F

The integrated APS flow is larger for the events with a greater cooldown rate because more spray flow was permitted as the more rapid cooldown raised the subcooling. (Note that the time to reach 1200 psig is less for the events with a greater cooldown rate.) If a PORV rather than an APS system were in place, the time to reach 1200 psig might be slightly less as a result of the more rapid depressurization capability of the PORV. However, the effect would probably not be significantly different because the depressurization is affected principally by the subcooling limit, not by the rate of depressurization per cycle (PORV lift or APS flow).

To evaluate situations in which the pressurizer could be filled water solid and the resulting effects on offsite consequences and plant control, ANL evaluated Cases 4, 4A, and 5 in which operator error was assumed to result in filling the pressurizer solid with water.

With respect to the radiological consequences of these cases, the staff notes that Cases 4, 4A, and 5 are not significantly different from the design-basis SGTR described in Cases 1 and 2. Filling the pressurizer solid with water inhibits the plant's ability to continue primary system depressurization and, therefore, would result in slightly greater primary-to-secondary leakage than would be expected for the design-basis SGTR case. Also there would be slightly higher integrated flow through the ADV.

Although the actual radiological consequences for these cases have not been evaluated, it would be expected that the increase in primary-to-secondary leakage in combination with the increase in the releases though the ADVs would result in radiological consequences slightly greater than those for the design-basis SGTR represented by Cases 1 and 2, but well below the radiological consequences expected for the multiple SGTR case described in Section 5 or the guideline values of 10 CFR 100.

The staff evaluated the system performance predicted by the ANL analyses because these cases represent situations in which the APS depressurization capability would be lost until the pressurizer steam void were regained. The capability of the PORV to continue the depressurization was also evaluated.

The results of ANL Case 4 showed that if the operator erred and continued safety injection and full APS flow, the pressurizer would be filled in about 500 seconds. The ANL calculation assumed that, despite the solid pressurizer, APS continued for 10 minutes longer; then the operator terminated APS and continued the 75°F/hr cooldown using the ADVs. High pressure safety injection (HPSI) was assumed to continue if the subcooling limits allowed.

Figures 4.1.4-2 and -3 in ANL/LWR/NRC-83-7 show the pressurizer level and RCS pressure. The RVUH void reached a maximum size of about 1400 ft^3 (Figure 4.4.4-17 of ANL/LWR/NRC-83-7), which was well above the top of the hot legs. The calculations showed that the cooldown-rate-induced contraction was enough to regain the pressurizer steam space about 10 minutes after APS flow was stopped. The calculation shows that once the pressurizer is filled, the HPSI flow collapses the RVUH steam void until the cooldown-induced depressurization causes the RVUH void size to increase to maximum of about 900 ft^3. At no time did the void extend down into the hot legs, and core cooling was always provided. The calculation shows that, as long as the cooldown continues, pressure reduction will take place.

ANL Case 5 examined the potential benefits of a PORV in this situation. That is, would opening a PORV at the time the pressurizer became water solid better enable the continued depressurization? Figure 4.1.5-7 of ANL/LWR/NRC 83-7 shows that the use of the PORV, once the system became water solid, did result in a more rapid RCS depressurization. The results did not show any appreciable difference in the RVUH void size as a result of using this means of mitigation. Also, the pressurizer level plot, Figure 4.1.5-2 of ANL/LWR/NRC 83-7, showed a slightly earlier restoration of the pressurizer steam space; thus the APS could have been used to continue the depressurization.

ANL evaluated one additional case, similar to Case 4, in which the RVUH void size was maximized. When the pressurizer became water solid, the APS and HPSI were both secured and the RCS cooldown was continued at 75°F/hr. This case, 4A, showed that the RVUH void stayed large, about 1440 ft^3, and the pressurizer steam space did not readily re-form. The staff recognized that this would be a very confusing situation for the operator. The pressurizer level indicates a full RCS, but the RVUH void is large. If the operator properly diagnoses the RVUH void presence, the operator may be able to manage the RCS pressure and cooldown. However, to collapse the RVUH void, the operator must continue HPSI flow, which, under normal circumstances would raise system pressure, a response the operator is trying to avoid in the recovery from a SGTR. A delay in the cooldown in an attempt to understand the plant status may result in RCS heatup and, potentially, lifting the damaged steam generator relief valve. (Figure 4.1.4-6 of ANL/LWR/NRC-83-7 shows that the damaged steam generator dome pressure has not appreciably dropped below about 1110 psig, only 90 psi below the relief valve setpoint). The staff notes that the indications and parameters in this situation are confusing, and although this is not a significant safety concern, it may result in further operator errors.

1.2.3 Fatigue Analysis of Pressurizer Spray Nozzle

In response to the staff's question regarding fatigue usage of the pressurizer spray nozzle, CE responded in CEN-239 that records of normal and auxiliary spray cycles and the temperature differential (ΔT) would be kept and the fatigue usage of the nozzle would be calculated. Further, CE stated that if the cumulative usage factor exceeded 0.65, an engineering evaluation would be conducted before future auxiliary spray cycles. At the July 7-8, 1983 meeting with CE (Liang, July 21, 1983), the staff requested a more definitive statement to ensure that the pressurizer spray nozzle would not have to be replaced as a result of excessive fatigue usage.

CE performed a fatigue analysis of the pressurizer spray nozzles to determine the cumulative fatigue usage factor on this nozzle. In the analysis, 150 cooldown cycles were assumed for the 40-year plant life. During each cooldown, four main spray and four auxiliary spray cycles were assumed. The ΔT during these cycles varied depending on the plant conditions at the time the spray cycle was assumed to occur. In addition, two natural circulation cooldowns were assumed, with eight auxiliary cycles during each cooldown. The cumulative fatigue usage factor for the nozzle, based on the above-mentioned cycles, was calculated to be 0.79.

The maximum allowable fatigue usage factor allowed by the Boiler and Pressure Vessel Code of the American Society of Mechanical Engineers (ASME Code) is 1.0. Therefore, CE concluded that the pressurizer spray nozzle fatigue would not reach 1.0.

The staff reviewed this information and notes that although the assumed nozzle fatigue calculation performed by CE appears conservative, there are no Technical Specification or procedural limits to restrict or in any way limit ΔT or the number of cycles. Thus, despite CE's calculation, there is nothing to ensure that the calculation bounds all possible cases. It should be noted that other PWR designs (by Westinghouse and Babcock and Wilcox and for earlier CE plants) have pressurizer nozzle ΔT Technical Specifications, and the current CE designs do not. The staff is still reviewing the necessity for Technical Specifications associated with a ΔT limit.

1.3 Conclusions

The APS systems in the current CE-designed plants rely on the safety-related charging pumps. Although CE states that the APS is a safety-related system, the staff determined that there are single failures within the APS that may significantly limit its ability to perform its safety function. Also, there are no Technical Specifications regarding equipment availability, surveillance, etc., for the APS. The staff has requested the applicants of CE plants without PORVs to address the potential single failures in the APS system and the need of developing Technical Specifications for the APS.

APS performance is similar to that of a nominally sized PORV, and is able to efficiently reduce system pressure as long as the pressurizer insurge is not excessive and the pressurizer steam space remains sufficiently large to allow efficient steam condensation.

The APS is able to efficiently mitigate the design-basis SGTR, as is an assumed PORV. The APS has the benefit of adding mass to the RCS during the SGTR accident, whereas the PORV accomplishes its depressurization function by mass removal, with the associated contamination of containment. However, the APS is limited to situations in which there is a pressurizer steam void. With the addition of a PORV, if the operator makes an error and inadvertently fills the pressurizer water solid, recovery would be possible, although complicated, and possibly enhanced. However, in general, the optimal means of recovery from a design-basis SGTR is with an APS system.

The pressurizer nozzle fatigue induced by normal or auxiliary spray at high ΔT has been calculated by CE to not exceed the ASME Code-allowable value of 1.0. However, the calculation cannot bound all possible methods of plant operation because, unlike the situation on other PWRs, there are no Technical Specifications to restrict the ΔT. This issue is still being studied by the staff.

2 QUESTION 2: Limiting Plant Scrams

This question asks if a PORV would provide any benefit in terms of avoiding plant scrams by limiting plant pressure.

2.1 CE Owners Group Response

Members of the CE owners group responded to this question by referencing Section 2.2 of CEN-239, which discusses the CE philosophy regarding PORVs. The response gives a table of peak pressures during a number of events at CE plants. CE stated that, in general, the CE plants have never relied on the PORV to avoid high RCS pressure reactor trips, as the Babcock and Wilcox (B&W) plants did before the accident at Three-Mile Island Unit 2 (TMI-2). The CE plants with PORVs are designed so that upon high RCS pressure trip, the PORVs are also opened. That is, the bistables in the reactor protective system that actuate high RCS pressure trip also actuate the PORVs.

The response also gives an overall philosophy of why PORVs were included in older CE plants and why they have been eliminated from the current CE plants.

2.2 Staff Evaluations

The CEN-239 response reiterates an earlier CE position regarding PORV setpoints. Unlike the pre-TMI-2 B&W design, the earlier CE plants have PORVs with setpoints at the high RCS pressure setpoint. Thus, whenever there was a high pressure trip, the PORVs would open. After the TMI-2 accident, CE, like all designers of PWRs, was asked about methods of avoiding PORV openings. The CE response, which was accepted by the staff, indicated that the design employing concurrent high pressure trip and PORV opening provided the optimal means of reaching the goals of minimizing challenges to the pressurizer relief valves and avoiding PORV lifts.

However, the newer CE plants do not have PORVs because operational experience evaluated in the mid 1970s indicated that the performance of other RCS pressure-reducing systems was such that even without the PORV, the safety valve setpoint would not be reached. The control-grade normal pressurizer spray (NPS) and steam bypass control (SBC) systems acted to quickly lower RCS pressure and remove RCS decay heat, respectively, during RCS pressurization events (loss of loads, turbine trip, loss of feedwater, etc.). Furthermore, CE stated that experience indicated the safety valve leakage occurred without pressure reaching the safety valve setpoint. Thus, the PORV would be helpful in limiting safety valve leakage only if it limited pressure far below the setpoint, which it was not designed to do.

Although the staff realizes that PORVs have not been assumed in safety analyses, PORVs have provided a useful but not essential function in limiting RCS pressure during rapid pressure transients. The removal of the PORV from the current CE plants places extra reliance on the SBC and NPS systems to prevent lifting of the pressurizer safety valves. Furthermore, there are design-basis events in which the SBC and NPS systems would not be able to prevent lifting of the safety valves. A loss-of-offsite power (LOOP) event results in a turbine trip, loss of condenser, and loss of forced RCS flow. Thus, a LOOP renders the NPS and SBC systems unable to limit RCS pressure; however, a LOOP normally results in a direct reactor trip and the RCS pressure rise is minimal.

The closure of both main steam isolation valves (MSIVs) is an event that removes the turbine and the SBC system as energy removal paths. This event, which occurred at the St. Lucie plant, would result in a rapid RCS pressure rise, a high pressure reactor trip, and a pressurizer safety valve lift. However, even if a PORV were installed, the safety valve would probably lift in this rapid loss of heat sink event.

The staff agrees that the normally available SBC and NPS systems limit RCS pressure to below the safety valve setpoint during many events; however, other events may occur in which the SBC system may not be available. In these events, the PORV may be able to prevent lifting of the pressurizer safety valve, with the possibility of a stuck-open safety valve and a small-break loss-of-coolant accident (SBLOCA).

The staff also notes that there are no Technical Specifications specifying equipment availability, limits, and surveillance for the SBC and NPS systems. However, these components are not relied on in any safety analyses included in the Final Safety Analysis Report (FSAR) for a plant. Thus, from a regulatory conformance standpoint, Technical Specifications are not required. The staff believes the absence of a PORV and the possibility of safety valve SBLOCAs should be addressed in the probabilistic risk analyses and defense-in-depth perspectives.

2.3 Conclusions

In terms of design-basis pressurization events, the PORV may be useful (by limiting safety valve lifts), but it is not relied on or necessary. However, the absence of a PORV places extra reliance in the SBC and NPS systems. There are no Technical Specifications for these systems, but none are needed because no credit is taken for the systems in any FSAR safety analyses.

3 QUESTION 3: Anticipated Transients Without Scram

This question asks for a discussion of the advantages and disadvantages of PORVs from the standpoint of anticipated transients without scram (ATWS).

3.1 CE Owners Group Response

In response to this question, the CE owners group evaluated the pressure response to an ATWS (loss of main feedwater) in the 3410-MWt and 3800-MWt plants to determine the additional relief capacity required to limit the peak RCS pressure to less than 3200 psi. The group noted that this additional relief capacity for the 3410-MWt plants is three to eight times larger than that provided by two PORVs typically installed in operating CE plants and would increase the susceptibility to a safety valve-initiated SBLOCA.

3.2 Staff Evaluation

The additional pressure relief capacity needed to limit the RCS pressure to 3200 psi following a severe ATWS is highly dependent on the plant characteristics and the analytical model used in the calculations. The CE owners group used a modified version of its best estimate ATWS code to analyze an AWTS from an LOFW event. The CE owners group cited CENPD-158, Revision 1 as the basis for identifying LOFW as the limiting ATWS event. In NUREG-0460, Vol 4, the staff noted that the LOFW event may be bounding; however, the existence of other transients (e.g., zero power CEA withdrawal) that are close to the LOFW in peak pressure (as shown in NUREG-0460, Vol 2) precludes a definitive finding on this issue.

The analytical model used by the CE owners group for estimating the plant response to an ATWS has not been reviewed by the staff. This model, which includes vessel head O-ring seal leakage to relieve the pressure, was presented in CENPD-263-P. In NUREG-0460, Vol 4, the staff noted that the description and justification of the O-ring seal leakage model presented was not sufficent to permit the staff to make a definitive finding on this model, which had a significant impact on the calculated peak RCS pressures. The modified version of the ATWS code used by the CE owners group contains other thermal-hydraulic modeling changes that have not been reviewed by the staff.

In CEN-239, the CE owners group presented the estimated peak RCS pressures for plants without PORVs, as shown in Table 7.

Table 7 Peak RCS pressure (psia)

Plant class	No turbine trip	With turbine trip
3410 MWt	4290	3843
3800 MWt	3800	2918

3.3 Conclusions

The proposed ATWS rule (SECY-83-293) requires a diverse turbine trip for all PWRs. On the basis of this assumption, the CE owners group concluded that additional relief capacity would benefit only the 3410-MWt plants with respect to limiting the peak RCS pressure to 3200 psi. The staff concurs that additional relief capacity would be beneficial for the 3410-MWt plants (for ATWS); however, because of the aforementioned unknowns associated with the calculational model, the staff can not conclude that additional relief would not be beneficial for the 3800-MWt plant as well.

The CE owners group cited, as a disadvantage of adding PORVs, the increased susceptibility of SBLOCAs as a result of stuck-open PORVs. The staff also shares a concern about the increased susceptibility for SBLOCA; however, the staff believes that adequate technology is available to minimize this susceptibility through the use of more reliable valves, automatic isolation capability, and design criteria of a broader scope for the added relief capacity system. On balance, the staff believes that additional relief capacity would be beneficial from an ATWS standpoint. This benefit is quantified in Section 11 below.

4 QUESTION 4: MITIGATING PTS

This question asks for a discussion of the possible benefits derived from the use of PORVs for mitigating pressurized thermal shock (PTS).

4.1 CE Owners Group Response

In response to this question, the CE owners group evaluated two very severe postulated overcooling events without the use of PORVs with the system assumed to repressurize to the RCS relief valve set pressure of 2500 psia. The two events considered were an intermediate-size main steamline break and a small main steamline break. The analyses were performed for the 3800-MWt plants, and the results are applicable to the 3410-MWt plants. The results of the CE analysis are reported in CEN-239.

4.2 Staff Evaluation

For conservatism, the analysis was performed for a steamline break during hot zero power operation. This mode of plant operation will maximize the primary coolant system cooldown because steam generator water inventory is large and core decay heat is low. Also, the analysis assumes no moisture carryover through breaks during the blowdown. This assumption will maximize total energy removal from the affected steam generator and thus maximizes integral RCS heat removal to further bound the effects of PTS.

A break was assumed in main steam piping upstream of the MSIV. The break initially increases steam flow from both steam generators; steam generator pressure and temperature decreases; and heat removal from the RCS increases. Low steam generator pressure initiates a reactor trip and main steam isolation. A low steam generator level in the unaffected steam generator starts the auxiliary feedwater flow to the intact steam generator, and during the transient, pressurizer pressure decreases to the SIAS setpoint. Two HPSI pumps and three charging pumps will be started, and the operator will manually trip all four RCPs following the SIAS. The HPSI pumps will rapidly repressurize the RCS to the HPSI pump shutoff head, and the charging pumps will further pressurize the RCS. The PTS concern arises because the rapid decrease of RCS temperature and the subsequent repressurization of the RCS by the HPSI and charging pumps.

4.3 Conclusions

The staff has evaluated the assumptions and plant parameters used for the steam-line break analysis and concluded that they are reasonably conservative and the results of the analysis could provide an upper bound on the cooldown rate during the transient. Fracture mechanics evaluations of the transients were performed using conservative assumptions. The results of the analysis shown that no crack initiation would occur for these transients and, therefore, from a PTS point of view, PORVs are not required in the CE 3410-MWt and 3800-MWt plants.

The studies performed by the staff as part of Unresolved Safety Issue (USI) A-49 also indicated that there are no significant concerns about CE plants without PORVs with respect to PTS.

5 QUESTION 5: Low Probability Events

This question asks each applicant to address multiple-failure scenarios, such as multiple SGTRs and SBLOCAs with failure of HPSI, to ensure they are satisfactorily handled without the use of the PORVs.

5.1 CE Owners Group Response:

In response to this question, the CE owners group evaluated system response and offsite consequences for both the 3410-MWt and 3800-MWt reactors under two multiple SGTR scenarios: one double-ended guillotine SGTR in each steam generator, and three double-ended guillotine SGTRs in each steam generator. To address the SBLOCA without HPSI, CE performed thermal-hydraulic calculations for the 3410-MWt class plants and reported the results in CEN-239. The evaluation of the TLOF accident, which is also a multiple-failure event, is in Sections 6 and below.

5.2 Staff Evaluation and Conclusions

5.2.1 Multiple SGTRs

5.2.1.1 Discussion

CEN-239 evaluated the system response and offsite consequences for the 3410-MWt and 3800-MWt reactors assuming one or three broken tubes in each steam generator. In evaluating the CEN-239 analysis and in discussion with the CE owners group, the staff noted that, in general, the analyses followed the guidelines specified in CEN-152. However, contrary to CEN-152, the analyses assumed that both steam generators would be continually steamed throughout the RCS cooldown and depressurization process. The CEN-152 instructs the operator to isolate the most affected steam generator and to cool down using only one steam generator. The CE analysis is probably conservative in this assumption, but the staff asked CE to determine system performance and offsite consequences if the operator followed the guidelines exactly.

The CE analyses (Section 2.5.2 of CEN-152) assumes depressurization with only the APS and did not compare the results assuming mitigation with a PORV, as the staff noted in a letter from C. Thomas (NRC) to A. Scherer (Thomas, April 29, 1983). The CE analysis did not address other multiple-failure scenarios, such as main steamline break (MSLB) or main feedline break (MFLB) coupled with consequential single or multiple SGTRs in the affected steam generator. However, in general, these events are depressurization events, with the exception of the early phases of the MFLB, and the ability of the APS or PORV to mitigate the effects are probably not relevant.

The CEN-239 thermal-hydraulic and offsite radiological consequences analyses were performed for one or three broken tubes in each steam generator. Analyses were not conducted for assymetric conditions (that is, different numbers of broken tubes in each steam generator. However, the CE method of assuming continuous steaming from both steam generators in symmetric multiple SGTRs probably bounds situations in which the operator properly isolates a damaged steam generator that contains more broken tubes. That is, the CE analysis is probably conservative with respect to asymmetric multiple SGTRs.

The CE analyses assumed no more than three broken tubes in each steam generator, although CE informally told the staff that the offsite radiological consequences would be much more severe for the case of five broken tubes in each steam generator. Table 8 shows the offsite radiological consequences for the multiple SGTRs scenarios evaluated in CEN-239.

Table 8 CEN-239 Multiple SGTR results

	3410-MWt Class		3800-MWt Class	
Parameter	1 broken tube/SG	3 broken tube/SG	1 broken tube/SG	3 broken tube/SG
RCS pressure (psia)	232	326	314	350
RCS temperatures (°F)	370	390	388	398
Integrated primary-to-secondary leak (lb_m)	313,400	717,100	360,400	860,126
Integrated HPSI (lb_m)	384,800	806,580	434,100	897,600
Integrated auxiliary feed-water to both SGs (lb_m)	292,900	0	275,000	0
Integrated MSSV flow from both SGs (lb_m)	101,300	111,300	112,200	97,700
Integrated ADV flow-from both SGs (lb_m)	487,400	401,000	507,000	513,900
Dose - 2 hr (rem)*				
GIS	55	45	105	95
PIS	95	80	230	220

*In calculating the dose results, the site dispersion factor for Waterford was used for the 3410-MWt case and the site dispersion factor for WPPSS was used for the 3800-MWt case.

In evaluating these results, the staff noted that the predicted offsite doses for cases of the three broken tubes in each steam generator were always less than those for the case of one broken tube in each steam generator despite the fact that the integrated leakage from the primary to secondary was always greater in the three-tube cases. In discussing this with CE, it was pointed out that because of the greater break flow in the three-tube case, the HPSI flow was larger, thus more RCS cooling was being afforded by the HPSI flow and less ADV flow was necessary for RCS cooling. The offsite doses are a function of the primary-to-secondary, the ADV, and the main steam safety valve (MSSV) flows, and in the multiple SGTRs cases performed by CE, the offsite dose results seem reasonable.

The staff asked CE why no breaks of more than three tubes in each steam generator were evaluated, especially because CE indicated that the offsite doses for a break of five tubes in each steam generator may be significantly higher. In response, CE informally stated that the probability analyses for each applicant in CEN-239 Supplement I (Baskin, June 22, 1983, and Drummond, June 29, 1983), showed that the probability of multiple SGTRs coupled with loss of offsite power is very low, and did not justify continuing analyses of larger numbers of broken tubes. The staff's analyses of the frequency and rate associated with multiple SGTRs is in Section 9 below.

The staff's contractor, ANL, performed specific multiple SGTR analyses for the 3800-MWt plant, following the CEN-239 guidance. The analyses were conducted for three cases, as shown in Table 9.

Table 9 Multiple SGTRs analyzed by ANL

Case Number	Comment
7	Dual SGTR with APS
8	Dual SGTR with PORV
9	Dual SGTR with PORV, feed and bleed (early isolation of both steam generators)

In general, the results of ANL Case 7 agreed with the results obtained by CE for the equivalent case; however, there were a number of differences in the analyses, as shown in Table 10. The resultant effects of these differences are also shown in Table 10.

Using the time-dependent primary and secondary conditions and release data, the staff estimated the potential offsite radiological consequences for a 3800-MWt plant using the assumptions in Table 5. Because ANL had performed analyses assuming mitigation with either the APS or the PORV, the staff analyzed the radiological consequences under both mitigation schemes. The staff calculations showed that using either the PORV or the APS, the offsite doses for one SGTR in each steam generator on the 3800-MWt plant would be less the 10 CFR 100 guideline values. Because the ANL analyses did not include a case of three SGTRs per steam generator, the staff can not substantiate the CE results. Similarly,

Table 10 Comparison of CE and ANL MSGTR analyses, differences, and resultant offsite dose effects

Item	CEN-239	ANL	Effects on dose
HPSI pumps	2	1	CE less than ANL
RCS cooldown rate	100°F/hour	75°F/hour	CE less than ANL
Reactor trip	600 sec (auto)	400 sec (auto)	CE less than ANL
Break location	Hot leg	Cold leg	--
First operator action	1800 sec	1200 sec	CE more than ANL
Operator actions	Both SG used heaters APS	Single SG used no heaters APS	CE more than ANL
Charging pumps	Only APS, on or off	Alternate APS to cold legs	CE more than ANL

the staff can not substantiate the CE results for the 3410-MWt plants because no system performance analyses were performed by ANL for a 3410-MWt plant.

ANL performed an analysis to determine if feed and bleed operation, using an assumed PORV and the existing high pressure safety injection pumps (HPSIPs), would be a viable means of limiting offsite consequences in multiple SGTR accidents. As described in ANL/LWR/NRC-83-7, Case 9 assumed the ADVs of both steam generators were closed when hot leg temperature reached 565°F and feed and bleed was initiated. The details of the transient are discussed in the ANL report. In general, break flow is rapidly reduced, then stopped, but the long-term recovery is extremely complicated because the steam generators act as an energy and mass source to the primary during the cooldown and depressurization to the shutdown cooling system entry conditions. It should be noted that the Code calculated unstable, oscillating RCS flow at various times, which may not be valid. However, the conclusion regarding this potential method of mitigating multiple SGTRs (one broken tube in each steam generator) seems to be that it is not a viable technique, because steam generators significantly retard the RCS cooling and depressurization from the PORV and HPSI flow.

The staff did not evaluate the viability and desirability of feed and bleed as a means of mitigating other, more complicated SGTR scenarios. For example, the offsite radiological consequences for a single SGTR with an ADV stuck fully open are above the 10 CFR 100 guidelines. This case is important because Palo Verde does not have block valves upstream of its ADVs. Also, the MSSVs will lift initially after the scram, and should a MSSV stick open, the release rate and pathway is the same as the case of the ADV fully stuck open that was analyzed.

The staff did not analyze the viability and desirability of feed and bleed in tube ruptures with more than one broken tube in each steam generator and a possible stuck-open ADV or MSSV in these situations.

The staff realizes these events are low probability events, and feed and bleed to mitigate these scenarios has not been assessed. It can be stated qualitatively, however, that in these scenarios, the use of feed and bleed would conserve the refueling water storage tank (RWST) inventory. That is, by opening the PORV and establishing feed and bleed, less RWST water is lost through broken tubes because the depressurization rate is greater with a PORV than with an APS or by contraction caused by the ADV cooldown.

5.2.1.2 Conclusions

In general, with respect to multiple SGTRs, the offsite doses for single SGTRs in each steam generator for the 3800-MWt plants are less than the 10 CFR 100 limits, regardless of which mitigation technique is used. Although the results for the 3410-MWt plants have not been substantiated, the staff believes these results have been suitably analyzed by CE, and the doses also are below the 10 CFR 100 limits.

The viability and desirability of feed and bleed as a means of mitigating single SGTRs or multiple SGTRs with a stuck-open ADV or MSSV were not assessed. In these cases, feed and bleed may be able to limit offsite doses and provide adequate core cooling. However, the desirability of using long-term recirculation in these scenarios must also be evaluated.

5.2.2 SBLOCA Without HPSI

To answer the question of how an SBLOCA without HPSI is satisfactorily mitigated without PORVs, an analysis was performed for this accident scenario both with and without the use of PORVs. For the case in which PORVs were not used, RCS depressurization was accomplished by means of aggressive steam generator cooldown with the ADVs. For the case in which PORVs were used, no steam generator cooldown was assumed.

5.2.2.1 Case 1: No Operator Action

An analysis was performed for the SBLOCA without HPSI when no action is taken by the operator to depressurize the RCS. The sequence of events during the transient is similar to that of an SBLOCA with HPSI except that the RCS inventory is negatively impacted by the absence of HPSI. The results of this transient indicated that the core begins to uncover at approximately 2600 seconds. The cladding temperature of the hottest fuel rod reaches 2200°F at approximately 3600 seconds, and the reactor inner vessel two-phase mixture level decreases below the bottom of the core at approximately 4100 seconds. At that time, the pressure of the RCS is still above the pressure of 600 psia, at which level the safety injection tanks (SITs) begin to inject water into the RCS. This base case shows unsatisfactory results for this accident scenario.

5.2.2.2 Case 2: Steam Generator Cooldown via ADVs

In this case, operator action was assumed to take place 15 minutes after the accident. In response to the accident, both ADVs are manually opened to initiate a rapid steam generator cooldown at the rate of 100°F/hour. The steam generator cooldown causes the RCS to cool down and depressurize. At approximately 3500 seconds, the RCS depressurizes to 600 psia, at which time the SITs begin to inject water into the RCS. The SIT injection rate exceeds the leak rate, and the RCS inventory begins to increase and keep the core covered. At 200 psia, the LPSI pumps begin to inject water into the RCS after the SITs are depleted.

The staff concluded that the assumptions made in this analysis were very conservative because the charging pump flow and auxiliary spray were not assumed to function during the transient.

5.2.2.3 Case 3: RCS Depressurization via PORVs

In this case operator action was assumed to take place at 15 minutes after the accident. Both PORVs were manually opened to initiate a rapid primary system depressurization in response to the accident. However, it was assumed that the operator does not cool down the steam generators or initiate the charging pumps during the transient. At approximately 1900 seconds, the core begins to uncover, and at approximately 2300 seconds, the SITs begin to inject water into RCS. The SITs do not provide sufficient flow to reflood the core.

5.2.2.4 Conclusions

The analysis shows that only the Case 2 has satisfactory results that do not cause core uncovery. If the charging flow or APS were assumed in the Case 3 analysis, the transient using PORVs might be more favorable than that in Case 2. However, the results of the analysis in Case 2 have demonstrated that an SBLOCA without HPSI could be mitigated without the use of PORVs. It must also be noted that the use of the ADVs relies on the steam generator as a means of cooling. If not available, for whatever reason, the PORV would provide a means of RCS depressurization.

6 QUESTION 6: Use of Low Pressure Pumps for Feeding Steam Generators

6.1 Question 6a: System Description and Use

Describe the system and its use, including water supplies and their capacity, flow paths, pumps, power supplies to components, control equipment, and procedures.

6.1.1 CE Owner Group Responses

Existing low pressure pumps such as condensate pumps may enable an operator to supply feedwater to the steam generators during certain low probability scenarios that are essentially beyond the design bases of the plant. For example, a scenario that started with a loss of main feedwater (MFW) as a result of a realtively minor failure in the MFW system or feedwater control system could result in a TLOFW if the first failure were followed by a multiple failure in the auxiliary feedwater system (AFWS) that prevented this system from functioning. In a situation where the AFWS is no longer available, an operator would have only about 10 to 15 minutes to find and correct the problem in the MFW system and restore that system before the inventory in the steam generators were depleted to the point where the turbine-driven MFW pumps could not be restarted (steam generator dryout). At this point, with both main and auxiliary feedwater pumps down and with insufficient inventory in the steam generators to restart a turbine-driven MFW pump, one or both steam generators could be depressurized via the ADVs to the point where a substitute pump such as a condensate pump could be used to supply feedwater for decay heat removal; if desired, a recovery of the MFW system could be performed.

Generic analyses were performed for the 3410-MWt and 3800-MWt plants. The results indicated that this method is a viable method for decay heat removal for which specific procedures and training could be developed. The results indicated that time to initiate depressurization and feed via a low head pump to prevent core recovery is 50 minutes for 3410-MWt plants and 59 minutes for 3800-MWt plants. According to this analysis, a flow rate of 2300 gpm at a shutoff head of 350 psia can provide sufficient decay heat removal to prevent core uncovery. In addition, initial review indicates that the best suited pump for use as a substitute feedwater pump is probably a condensate pump. The condensate pump appears to be ideally suited for this application because system lineup for feedwater delivery can be readily accomplished, pump flow characteristics are usually such that only modest steam generator depressurization need be accomplished prior to delivery, and the supply of available feedwater is of high quality. The condensate pumps are powered from the offsite power source. A second possible candidate for use as a subsitute feedwater pump would be an emergency firewater pump. The advantage of using this pump would be the availability of an emergency onsite power supply; however, the system lineup necessary to initiate feed is somewhat more difficult than it is with the condensate pump, and the water would be of a lower quality.

The actual equipment and interface requirements for this application are plant specific and have been supplied by individual utilities. Further discussion of the generic analyses including assumptions and results is provided in Section 6.3.

6.1.2 SONGS Responses and Evaluation

6.1.2.1 SONGS Responses

In the unlikely event of a loss of both main and auxiliary feedwater at SONGS-2 and 3, there are several sources of low pressure water available for use as makeup to the steam generators. The preferred source would be the condensate system of the affected unit. The four condensate pumps have a shutoff head of 500 to 600 psig, receive water from multiple sources (e.g., hotwell, condensate storage tanks, demineralizer makeup), and, through use of the feed pump bypass line, can deliver makeup directly to each steam generator. Each condensate pump has a rated capacity of 7750 gpm. The condensate pumps are powered from the offsite power source. The normal condensate makeup sources (hotwell and condensate storage tanks) contain 746,600 gallons. If additional makeup is required, there are several alternate means to refill the condensate storage tanks. Makeup grade water is available from the condensate system of the companion unit through the condensate cross-tie line and from the onsite demineralizer system. As a backup to these sources, service-grade water is available from the fire protection system of Units 2 and 3 as well as from that of Unit 1. The fire protection reserve for Units 2 and 3 is 750,000 gallons, and Unit 1 has a 3-million-gallon reservoir. This means that there is more than 5 million gallons of onsite condensate makeup water available to the SONGS-2 and -3 steam generators to supplement the AFWS. There is also a virtually unlimited supply of potable water available from the domestic water system.

The licensee also suggested the use of a condensate transfer pump (100 gpm at 65 psig) for operation in the depressurized mode.

The alternate means of using condensate pumps to remove decay heat from the core involves only a minimal change in the normal feed valve lineup in conjunction with depressurization of a steam generator by the ADVs. The condensate system is lined up to directly feed a steam generator with the main feed pumps bypassed and isolated.

The licensee has provided a detailed outline of the steps that may be followed for a loss of the main and auxiliary feedwater pumps. The alignment of the condensate pumps to the steam generator can be completed from the control room, with the exception of opening the two main feed pump bypass valves, which must be accomplished by local manual operator action. All other operations, including control of steam generator pressure and water level, are completed following existing SONGS-2 and -3 procedures.

6.1.2.2 Staff Evaluation of SONGS-2 and -3

The use of condensate pumps for alternate decay heat removal in the event of loss of main and auxiliary feedwater pumps is a viable method to provide flow to the steam generators for decay heat removal, in accordance with the CE owners group generic analysis for the TLOFW event with offsite power assumed available. The SONGS-2 and -3 condensate pumps, with a rated capacity of 7750 gpm and a shutoff head of above 500 psig, can satisfy the analysis requirements. Therefore, these pumps are adequate for the alternate decay heat removal purpose. In response to a staff question in the meeting held on July 7 and 8, 1983, the licensee confirmed that the flow could be throttled to avoid overcooling. The capacity of the pump's water supply source is also adequate for long-term operation in this mode.

However, the use of condensate transfer pump at 65 psig is not a viable technique because it does not meet the analysis requirements; therefore, no credit can be given for this pump.

The staff has reviewed the SONGS-2 and -3 plant-specific guidelines and has concluded that there is sufficient information in these guidelines so that procedures for using the condensate pump to supply feedwater to the steam generator can be written. On the basis of the analysis referenced and on the draft Standard N660 of the American National Standards Institute (ANSI), the staff also concludes that adequate time would be available for the operator to perform the indicated manual actions. The licensee should factor this new operator guidance into the overall response to supplement 1 to NUREG-0737.

6.1.3 Waterford 3 Responses and Evaluation

6.1.3.1 Waterford 3 Responses

Two low pressure systems have been identified as providing the potential capability for alternate decay heat removal (ADHR) if the emergency feedwater system (EFWS) is not available after a loss of main feedwater. It should be noted that the EFWS in Waterford Unit 3 is the same as the AFWS in other plants. The preferred method, if offsite power is available, is to use the condensate pumps to supply water to the steam generators. If offsite power is not available, the applicant has proposed the use of a diesel-driven firewater pump at low pressure. The applicant has also described the possibility of adding an auxiliary feedwater pump as part of the ADHR capability. The ADHR capability is described below.

(1) Condensate System

The condensate system is composed of three 50% capacity condensate pumps, several trains of feedwater heaters, and the required piping and valves. Each pump has a rated flow capacity that exceeds 10,000 gpm and a shutoff pressure of about 500 psia. Power for the condensate pumps is obtained only from offsite sources. These pumps can supply sufficient water to the steam generator through the normal feedwater path. The main feedwater pumps and various heater stages can be bypassed if necessary.

The normal condensate makeup sources include the condenser hotwell and condensate storage tank. These sources contain 368,500 gallons of makeup-grade water. If additional makeup water is required, a virtually unlimited supply of potable water is available from the domestic water system through the demineralized water system.

(2) Firewater System

The firewater system can be modified to provide supplemental water to the steam generators if offsite power is not available. A diesel-driven firewater pump with a shutoff pressure of 120 psig and maximum flow rate of 2000 gpm is available. Some piping modifications would have to be made to provide a flow path from the firewater pump to the blowdown line of the steam generator. Special flanges could be used to allow quick connection of fire hoses, or more permanent piping could be installed. The procedure guidelines for use of the firewater system assume that special flanges would be used. However, the applicant has indicated that a permanently installed connection with shutoff valves would be a better arrangement.

Two firewater storage tanks provide a total of 520,000 gallons of water. Additional makeup water is available from the domestic water system through the primary water treatment system.

(3) Auxiliary Feedwater Pump

The applicant is evaluating the use of an additional feedwater pump that could serve as part of the ADHR capability. This pump would have a discharge pressure equivalent to normal operating pressure and a steam generator delivery flow rate equivalent to that of an auxiliary feedwater pump. A dedicated diesel generator is being considered so that the pump could be operated if offsite power were lost. Suction would be taken from a source of clean, demineralized water such as the condensate storage tank. This auxiliary feedwater pump would be capable of providing enough water to the steam generators to first depressurize and remove decay heat from the RCS without the need to depressurize the steam generators. The Waterford 3 Safety Review Committee has recommended that additional studies be conducted on the use of an auxiliary feedwater pump for ADHR.

6.1.3.2. Staff Evaluation of Waterford 3

The use of condensate pumps for ADHR in the event of loss of main and auxiliary feedwater pumps is a viable method to provide flow to the steam generators for decay heat removal in accordance with the CE owners group generic analysis for the TLOFW event with offsite power assumed available. The Waterford 3 pumps have a flow rate that exceed 10,000 gpm and a shutoff head of 500 psia (vs. 2300 gpm and 350 psia in the CE owners group analysis). In response to the staff's question in the meeting on July 7 and 8, 1983, the applicant confirmed that the flow could be throttled to avoid overcooling. Therefore, the results of the CE owners group generic analysis are bounding for Waterford 3.

The staff concludes that steam generator depressurization with feedwater injection from one condensate pump is a viable method of recovering from the TLOFW transient. However, analyses presented to date do not support this conclusion for the fire pumps. Consequently, no credit should be taken for fire pump operation. A detailed discussion of the staff scoping calculation for fire pump availability is in Section 6.1.2.3.

The use of an auxiliary feedwater pump as an ADHR system with an independent onsite power source is a useful concept, particularly because it does not require steam generator depressurization. The staff encourages the applicant to continue to pursue this option.

The staff has reviewed the plant-specific guidelines submitted by Waterford 3 and has concluded that there is sufficient information in the plant-specific guidelines so that procedures can be written to use the condensate pump to supply feedwater to the steam generator. Based on the analysis referenced above and on the use of draft ANSI N660, the staff also concluded that adequate time would be available for the operator to perform the indicated manual actions. The applicant should factor this new operator guidance into the overall response to Supplement 1 to NUREG-0737.

6.1.4 Palo Verde Response and Evaluation

6.1.4.1 Palo Verde Response

In the unlikely event of a loss of main and auxiliary feedwater at Palo Verde Units 1, 2, and 3, the operator would proceed to feed the steam generators with the low pressure condensate system of the affected unit. The condensate system of each unit consists of three 50% capacity condensate pumps, several trains of feedwater heaters, and the required piping and valves. Each pump has a rated flow capacity of 9100 gpm and a shutoff pressure of 540 psia. Power for the condensate pumps is obtained only from offsite power. These pumps can supply sufficient water to the steam generator through the normal feedwater path.

The condensate pumps take their suction from the condenser hotwell, which has a nominal normal inventory of 100,000 gallons. Makeup to the hotwell is made up via gravity feed from the condensate storage tank (CST), which has a capacity of 550,000 gallons. However, 330,000 gallons is dedicated storage for auxiliary feedwater, leaving 220,000 gallons for condensate makeup. As a backup to the

CST, the demineralized water tank (capacity 125,000 gallons) supplies makeup to the CST via the two demineralized water transfer pumps (capacity 312 gpm each). Therefore, approximately 455,000 gallons of condensate quality water is readily available to feed the steam generators within the affected unit. Identical amounts are available from the other two Palo Verde units via a common condensate crosstie line.

In addition to having condensate storage capabilities, the demineralized water makeup system is designed to supply condensate-grade water to each demineralized water tank at a design rate of 400 gpm continuously and a maximum rate of 600 gpm.

The applicant has also suggested the use of the unaffected units' condensate pumps to feed the affected units' steam generators. A detailed procedure guideline and valve alignment describing use of the affected or unaffected units' condensate pumps have been provided by the applicant. The alignment requires some manual operation outside the control room, but most of the alignment can be performed from the control room.

6.1.4.2 Staff Evaluation of Palo Verde

The use of condensate pumps for alternate decay heat removal in the event of loss of main and auxiliary feedwater pumps is a viable method for providing flow to the steam generators for decay heat removal in accordance with the CE owners group generic analysis for a total loss of feedwater event with offsite power assumed available. The Palo Verde pumps have a flow rate of 9100 gpm and a shutoff head of 540 psia (rather than 2300 gpm and 350 psia as assumed in the CE owners group analysis). The flow could be throttled to avoid overcooling. Therefore, the results of the CE owners group generic analysis are applicable for Palo Verde Units 1, 2, and 3.

The staff concludes that steam generator depressurization with feedwater injection from one condensate pump is a viable method of recovering from a TLOFW transient.

The staff has reviewed the plant-specific guidelines submitted by Palo Verde 1, 2, and 3 and has concluded that there is sufficient information in the plant-specific guidelines so that procedures can be written to use the condensate pump to supply feedwater to the steam generator. On the basis of the analysis referenced above and on the use of draft ANSI N660, the staff also concludes that adequate time would be available to perform the indicated manual actions. The staff will require, through licensing actions, that the applicant factor this new operator guidance into the overall response to Supplement to NUREG-0737.

6.2 Question 6b: Water Chemistry Interface Requirements

Describe the water chemistry interface requirements for the proposed low pressure system to ensure that its use will not cause unacceptable steam generator integrity degradation or heat transfer capability.

6.2.1 CE Owners Group Response

The concern is addressed in Question 7.

6.2.2 SONGS Responses and Evaluation

6.2.2.1 SONGS Responses

Of the alternate sources of water discussed in Question 6.1, the limiting worst case water chemistry (to be utilized after all secondary condensate makeup is expended) is drawn from the fire protection system without water treatment.

6.2.2.2 Staff Evaluation of SONGS-2 and -3

A detailed discussion is provided in Question 7. The normal condensate makeup can provide secondary grade water for approximately 6 hours and therefore the probability of corrosion and heat transfer degradation due to service grade water is limited.

6.2.3 Waterford 3 Responses and Evaluation

6.2.3.1 Waterford 3 Responses

As discussed in Question 6.1, demineralized water is used to feed condensate and feedwater pumps and potable water is used for the firewater pumps. Additional discussion is provided in Question 7.

6.2.3.2 Staff Evaluation of Waterford

A detailed discussion is provided in Question 7. The use of demineralized water to supply the condensate pumps is acceptable since it is secondary grade water. As discussed in 6.1, the firewater pump cannot be used due to low shutoff head and, therefore, lower grade water will not be used by Waterford.

6.2.4 Palo Verde Responses and Evaluation

6.2.4.1 Palo Verde Responses

All the alternate sources of water discussed in Question 6.1 are of high quality, secondary grade.

6.2.4.2 Staff Evaluation of Palo Verde

A detailed discussion is provided in Question 7. The use of secondary grade water to supply the condensate pumps is acceptable. No unacceptable steam generator integrity degradation or loss of heat transfer capacity would be anticipated using the identified water sources for the alternate decay heat removal schemes.

6.3 Question 6C: Steam Generator Blowdown

Show that blowdown of the steam generator is a viable depressurization technique without adverse core cooling consequences. Show that a concurrent rapid primary system cooldown and potential primary system contraction do not result in inadequate core cooling or a return to power.

6.3.1 CE Owners Group Responses

In response to this question, the CE owners group performed analyses to demonstrate that steam generator depressurization, actuated in the late stages of a TLOFW event could depressurize the primary system and remove decay heat without resulting in core uncovery or a return to power. The analyses were performed for both the 3410-MWt and the 3800-MWt classes of plants. The complete transient results for the 3410-MWt plants are presented in the CE owners group submittal. The results for 3800-MWt plants are very similar and, therefore, were not reported.

In the TLOFW event analyzed (for a 3410-MWt plant), offsite power was assumed available. Consequently, the reactor tripped after 20 seconds and the RCP were manually tripped at 10 minutes. The steam generator dried out at 10 minutes, the primary system safety valves opened shortly thereafter, and primary system inventory began to deplete. At 50 minutes into the transient, the steam generator contained a dry steam at 2500 psia, and the two-phase mixture level in the reactor vessel was less than 4 feet above the top of the core. At this point, one ADV in each steam generator loop was opened.

Secondary pressure fell rapidly to 200 psia, and feedwater injection commenced at 52 minutes at a rate of 2300 gpm. The assumed condensate pump shutoff head was 350 psia. Over the ensuing 600 seconds, condensate pump injection cycled on and off as steam generator pressure oscillated above and below the shutoff head as a result of the alternating pulses of rapid feedwater injection and rapid steam relief. Steam generator level rose steadily with each succeeding cycle.

The CE owners group submittal demonstrated that the steady state-steam relief capacity of the ADVs was more than a factor of two greater than would be required to remove decay heat 30 minutes after trip (1.87% of full power) plus the RCP power (20 MW). Under the aforementioned oscillatory conditions, the ADV relief rate averaged less than the steady state value. However, with the decay heat reduced (50 minutes versus 30 minutes) and the RCPs tripped, the ADVs were able to remove decay heat and cool the primary system. RCS pressure dropped rapidly from 2500 psia at 52 minutes to the HPSI shutoff heat (1420 psia) at 56 minutes, and to the SIT setpoint (615 psia) at 62 minutes. At this point, the calculation was terminated.

Although the rapid cooldown would tend to reduce core voiding and suppress the two-phase mixture level, the CE owners group submittal presented calculations to show that this reduction in level would be more than compensated for by steam condensation, and that under certain circumstances the cooldown would result in the transfer of pressurizer water to the reactor vessel. Consequently the core did not uncover.

The rapid reduction in RCS temperature would result in a sizable positive reactivity insertion, particularly at the end of a cycle. The CE owners group submittal asserts that this effect would be offset by the high boron concentration as a result of two factors: (1) charging pump injection of borated water and (2) the concentration of boron resulting from the boiloff of reactor coolant (boron has very low volatility). Furthermore, the core would still be partially voided after depressurization. The submittal presented no numerical analysis of these competing effects. In response to a telephone inquiry, the CE owners group provided preliminary calculations of the actual boron concentrations in the RCS compared to the concentrations required to prevent return to power.

At a conservatively low temperature of 40°F, using conservative values for the moderator and Doppler temperature coefficients, with no credit for voiding or xenon buildup, and with one control rod assembly stuck in the out position, the necessary boron concentration to prevent criticality is 370 ppm for the 3410-MWt plants and 360 ppm for the 3800-MWt plants (CESSAR 80). The actual estimated concentration, assuming zero initial concentration and minimum Technical Specification concentrations for HPSI and charging, would be 1154 ppm for the 3410-MWt plants and 538 ppm for 3800-MWt plants (CESSAR 80). The basis for these calculations will be documented by the applicant.

6.3.2 Staff Evaluation

The TLOFW transient analyzed by the CE owners group represents the most challenging credible test of the proposed steam generator blowdown technique. The analysis was performed in a best-estimate mode using accepted analytical methods (CEFLASH-4AS). The results have been examined by the NRC staff and found to be reasonable. Hand calculations have been performed to verify some of the assumptions.

The CE owners group conclusion that recovery of the heat sink late in the transient can reduce primary pressure without core uncovery is supported by confirmatory calculations performed by ANL. In case 2I of the ANL calculations on the TLOFW event for System 80 (ANL/LWR/NRC 83-6), ANL demonstrated that recovery of auxiliary feedwater 50 minutes into a TLOFW with offsite power available will rapidly reduce system pressure and avoid core uncovery. The ANL results are not directly applicable, however, because recovery of AFW does not require opening of the ADVs and there is no oscillation in feedwater flow.

The success of the steam generator depressurization method depends on the steam relieving capacity of the ADVs. If there is water in the steam generator and if the pressure is maintained in the vicinity of 350 psia, the steam relief rate of the ADVs will be sufficient to remove decay heat and rapidly cool the primary system. The CE owners group submittal demonstrates that steam generator water level rises steadily, in spite of the oscillatory behavior of the pumps. Furthermore, steam generator pressure oscillates about the assumed pump shutoff head (350 psia), and the ADV relief rate oscillates accordingly, with an average relief rate in the vicinity of the steady-state relief rate for 350 psia. For a pump of lower shutoff head, the relief rate will be proportionally lower.

The CE owners group calculations demonstrate to the satisfaction of the staff that the steam generator depressurization technique is viable for pumps that are capable of delivering 350 psia water to the steam generator. However, scoping calculations performed by the staff indicate that the technique will not work below 120 psia. Calculations performed by CE owners group but not included in its submittal showed that the if 120-psia shutoff head fire pumps at Waterford were used in the depressurization model, they could remove decay heat, but could not depressurize the primary system below 2200 psia. Core uncovery was observed for a period of 500 seconds in those calculations, but clad temperatures did not reach 2200°F. Given the uncertainties in initial conditions, analytical methods, and modeling assumptions, this result does not constitute sufficient assurance that steam generator blowdown with the Waterford fire pumps can successfully recover from a TLOFW transient.

The staff concludes that steam generator depressurization with feedwater injection from one condensate pump is a viable method of recovering from a TLOFW. However, analyses presented to date do not support this conclusion for the fire pumps. Consequently, no credit should be taken for fire pump operation in this mode of operation (see Waterford PRA; Page 6-121).

The staff concurs with the CE owners group analysis that demonstrates that core uncovery will not result from coolant shrinkage during rapid cooldown.

Finally, the CE owners group has demonstrated with a sufficient degree of conservatism that there will not be a return to power following rapid cooldown.

6.4 Question 6D: Dry Steam Generator

Show that there are no adverse consequences when a dry stream generator is fed with the low pressure system.

6.4.1 CE Owners Group Response

Early CE designs, which relied upon manually initiated AFW, specified that there were to be a limited number of feedwater initiations to a hot, dry steam generator. Although this specification was deleted when the design called for automatically initiated AFW, calculations have indicated that the 3410 and the 3800-MWt plants are capable of accepting a limited number of initiations of 70°F feedwater to a hot, dry steam generator via the feedwater ring and downcomer. Initiation of the feedwater in such an in extremis situation would represent a last resort effort to provide core cooling and prevent core damage. Following such an initiation, the structural integrity of the steam generator would have to be evaluated (on a plant-specific basis) once the RCS was safely cooled, before operation was resumed.

CE was asked to address a potential concern about waterhammer under the above conditions (by a telephone call on July 26, 1983). In response, CE noted that the waterhammer test performed in every plant before operation simulates more conservative test conditions than those that exist in a boiled-dry steam generator. Furthermore, procedures will be written to initiate feedwater to a hot, dry steam generator at a lower flow rate than that used in the waterhammer test.

6.4.2 Staff Evaluation and Conclusion

The staff concludes that the above response regarding the structural integrity of the steam generator is acceptable. Also, the staff concerns regarding waterhammer have been satisfied by this response.

6.5 Question 6E: Steam Generator Pressure Rise

If steam generator pressure rises above the shutoff head of the low pressure pumps intended to be used, describe the method of regaining feed flow without compromising core cooling.

6.5.1 CE Owners Group Response

As described in Section 6.3, the CE owners group analysis of the TLOFW event showed that steam generator pressure repeatedly exceeded the condesate pump shutoff head, and feedwater flow ceased. In each instance, steam flow out of the ADV continued and eventually reduced pressure to below the shutoff head. Renewed feed flow would then produce a new surge of steam production, pressure would rise, and the cycle would repeat. Nevertheless, the CE owners group calculations showed uninterrupted decay heat removal, system depressurization, and continuous core coverage.

6.5.2 Staff Evaluation and Conclusion

With the ADVs open, the steam generator pressure cannot remain above the pump shutoff head for very long. As long as steam flow out of the ADV is sufficient to remove decay heat and cool the primary, cyclic flow to the steam generator is acceptable. The recirculation line for the condensate pump prevents dead heading of the pump during cycling and ensures pump operability.

6.6 Conclusions

The staff concludes that steam generator depressurization and feedwater injection using the condensate pumps is a viable method of recovering from a TLOFW transient. These pumps provide a useful capability to the operator to supply water of secondary quality to the steam generators assuming offsite power is available, in the event of a loss of all main and auxiliary feedwater beyond the design basis of the plant. Plant-specific procedures should be developed for guidance on use of this decay heat removal method. However, use of a firewater pump or condensate transfer pump as an alternate decay heat removal source is not feasible under the assumed conditions, because not enough decay heat is removed to prevent core uncovery.

In addition, the staff recommends that Waterford continue to investigate the practicality and advantages of the proposed additional AFW pump to increase the reliability of the secondary side decay heat removal capability.

Note: The staff evaluation of the Palo Verde responses will be provided later.

7 QUESTION 7: STEAM GENERATOR TUBE INTEGRITY

This question asks each applicant and licensee to fully describe the chemistry effects on steam generator tube integrity.

7.1 CE Owners Group Response

When there is no PORVs greater reliance is placed on steam generator tube integrity to accomplish safe shutdown. CEN-239, dated June, 1983, provided some information in response on staff concerns about plants that do not have PORVs and a draft memo dated July 21, 1983, provided additional information.

7.2 Staff Evaluation

The steam generator tubes are alloy-600, fabricated in the mill annealed condition. The CE owners group has performed high temperature isothermal and heat transfer corrosion tests of alloy-600 in environments faulted with sea water and fresh water. These tests included exposure to sea water for several weeks at operating temperature pressure and to fresh water simulating emergency plant cooldown conditions. In both the sea and fresh water tests, only pitting that penetrated less than 5% through the tube walls was observed. Additionally, field experience has shown only minor corrosion in operating steam generators where condenser tube ruptures have resulted in highly faulted secondary water chemistry. On the basis of these tests, the staff has reasonable assurance that tube integrity will not be imparied because of corrosion as a result of a cooldown in which main condenser cooling water with faulted feedwater is used as makeup to the steam generators.

The steam generator tube supports and structural members that are not part of the primary pressure boundary are fabricated of a variety of carbon and stainless steels. These steel components are more susceptible than alloy-600 to general and localized corrosion mechanisms. On the basis of expected corrosion rates, short-term exposures to faulted water chemistry are unlikely to cause structural failure of steel components. However, after a steam generator operates with highly faulted water chemistry, it will have to be inspected to verify its integrity before restart.

The steam generators are fabricated so they have approximately 110% of their rated heat transfer surface area. During an emergency cooldown, when condenser cooling water faulted impurities would be injected to the steam generators, the total heat load is less than 3%. Therefore, a significant excess of heat transfer surface area exists during cooldown. Because of the excess of heat transfer area under cooldown conditions, heat flux through the tube walls is only a fraction of operating heat flux. The reduced heat flux produces only a small amount of boiling in the steam generators. As a result, concentration gradients and dry-out regions on the alloy-600 heat transfer tubing are minimized, and the potential for fouling of heat transfer surfaces is significantly reduced. On the basis of the above, the staff has reasonable assurance that the heat transfer surface will not be fouled to the extent that cooling functions are impeded during a cooldown that uses main condenser cooling water as feedwater to the steam generators.

7.3 Conclusions

On the basis of the above evaluation, the staff concludes that the structural integrity and heat transfer capabilities of the steam generators will not be impaired during the time it takes to reach safe shutdown when main condenser cooling water is used as feedwater. Therefore, the staff has reasonable assurance that the steam generators can be relied on for heat removal during emergency cooldown conditions when main condenser cooling water must be used as feedwater. However, the staff will require, through licensing actions, that the steam generators are inspected before restart to verify their integrity.

8. QUESTION 8: EXTENDED LOSS OF MAIN FEEDWATER

8.1 Question 8A: Frequency of Loss of Main Feedwater

This question asks for the frequency of loss of main feedwater, and asks that this frequency be broken down into initiators that affect more than loss of main feedwater.

8.1.1 CE Owners Group Response

CE estimated the frequency of loss of main feedwater to be 1.23/year (median value) for SONGS-2 and -3, and 0.71/year for Waterford; this estimate was based on a combination of operating experience and fault tree analysis. However, the response to this question does not explicitly identify the contribution to this frequency of loss of offsite power events or of other events that may also degrade mitigating systems.

8.1.2 Staff Evaluation and Conclusion

The staff estimates the frequency of total loss of main feedwater at about 1/yr at both these sites. The staff's estimate is taken from the Arkansas Nuclear One Unit 1 (ANO-1) IREP study (NUREG/CR-2787) and is based on an analysis of historical data. Of the events that can cause loss of main feedwater, loss of offsite power is of special interest. On loss of offsite power, the unavailability of the auxiliary feedwater system is increased and the condensate pumps are unavailable, so that the use of the condensate pumps to supply water to the steam generators, after the steam generators are depressurized, is not possible. CE estimated the frequency of loss of offsite power at SONGS-2 and 3 to be 0.04/year, and at Waterford to be 0.2/year. The staff estimates the frequency of loss of offsite power at both these sites to be about .12/year. The staff estimate of 0.12/year for the loss of offsite power frequency was taken from the station blackout analysis report, NUREG/CR-3226, and corresponds to an average over the entire population of U.S. plants.

Loss of dc power, either as an initiator or after loss of ac power, is not a significant issue with regard to the issue of installing PORVs in CE plants. It is a consequence of the multiple redundancy of dc busses, combined with the separation of dc loads.

8.2 Question 8B: Recovery of Main Feedwater

This question asks for the probability of recovery of main feedwater.

8.2.1 CE Owners Group Response

CE gave no credit for recovery of main feedwater except to consider implementation of an alternate secondary decay heat removal capability. At SONGS-2 and -3, this requires the use of the condensate pumps, and therefore requires the availability of offsite power. For the Waterford plant, CE gave some credit for a diesel-driven fire pump.

8.2.2 Staff Evaluation and Conclusion

For loss of main feedwater transients not caused by loss of offsite power, CE estimated, by fault tree analysis, that the probability of failure of the alternate secondary decay heat removal path (i.e., depressurization of the steam generators and using the condensate pumps) was 0.056 for the SONGS-2 and -3 plants. A 0.05 probability of human error was assumed. From the examination of historical data on loss of main feedwater events, the staff has made a rough estimate of the fraction of all loss of main feedwater events in which the condensate pumps would be unavailable, and estimates this to be 0.1 (given offsite power available). If the same human error probability used by CE is added, the estimated unavailability of the alternate secondary decay heat removal path is 0.15 instead of the value of 0.056 used by CE for loss of main feedwater transients not caused by loss of offsite power.

The staff does not concur with the CE owners group that the diesel-driven fire pumps at Waterford provide an effective alternate water source. The staff believes there is considerable uncertainty as to whether this pump would function properly, because of its low shutoff head.

None of the analyses gave credit for recovery of main feedwater following a loss-of-offsite power event. If offsite power is recovered after the steam generator dries out, it will not be possible to drive the turbine-driven main feedwater pumps. Any possible conservatism introduced is small, since recovery of offsite power permits recovery of the auxiliary feedwater system with high probability.

The staff has identified certain discrepancies in the CE calculation of the probability of failure of the alternate secondary decay heat removal system, which will increase this failure probability by a factor of 5 for SONGS-2 and -3. These discrepencies have been corrected in revision 1 of CEN-239, for SONGS-2 and -3.

8.3 Question 8C: Loss of All Auxiliary Feedwater

This question asks for the probability of losing all auxiliary feedwater, given loss of main feedwater.

8.3.1 CE Owners Group Response

In its original submittal (CEN-239), CE estimated the failure probability of the SONGS-2 and -3 auxiliary feedwater system to be 2×10^{-6}/demand, including credit for recovery actions. This is a failure probability averaged over all initiators. For Waterford, the CE value for failure probability of the auxiliary feedwater system was 3×10^{-5}/demand, including recovery actions. These values are subject to correction by CE.

8.3.2 Staff Evaluation and Conclusions

The staff also assessed the unavailability on demand of the SONGS auxiliary feedwater system and obtained a mean value of 6×10^{-5}/ demand for a loss of main feedwater transient with offsite power available, and obtained a mean value of 2.5×10^{-4}/demand for the case in which offsite power is not available.

One should note that given a loss of offsite power, there is a contribution to the unavailability on demand of the auxiliary feedwater system from sequences involving station blackout. Averaging the possible ways of losing main feedwater, one obtains approximately 8×10^{-5}/demand, which meets the goal.

Sandia National Laboratory, consultants to the staff, estimated (NUREG/CR-3421) the unavailability of the auxiliary feedwater system at SONGS to be 2.2×10^{-6}/ demand for a loss of main feedwater system transient (with offsite power available), and estimated the unavailability to be 8×10^{-5}/demand for a loss of offsite power transient.

Certain types of dependent failures are very difficult to model explicitly in fault tree models and to quantify properly through explicit modeling. One way of quantifying such dependent failures is through the beta factor method of Fleming (see NUREG/CR-2300). The staff calculation of the reliability of the auxiliary feedwater system used this method. The beta factors for the auxiliary feedwater system pumps were taken from the work of Atwood (NUREG-2098), and those for the high pressure injection system pumps were taken from the Sandia review of the Indian Point probabilistic safety study (NUREG/CR2934). These beta factors were used for component failures, not command faults.

Part of the difference in the estimated AFW unavailabilities is the statistical procedure used in the calculations. The Sandia estimates are point estimates, where the estimates of the basic component failure rates are median values. The CE estimates are median values, obtained by propagating the uncertainty distributions on the basic failure data and obtaining the median for the resulting system failure probability. The staff calculations are mean values using data from NUREG/CR-2815.

On the basis of this review, the staff has reconfirmed that the reliability of the auxiliary feedwater system designs for CE plants under consideration remains in the high ($\sim 10^{-4}$/demand) category.

8.4 Question 8D: Uncertainty of Estimates

This question asks for the uncertainty in the estimates of the frequency of loss of main feedwater events, of the probability of recovering main feedwater, and of the probability of recovering auxiliary feedwater.

8.4.1 CE Owners Group Response

CE gives the uncertainty bands on the frequency of the loss of main feedwater initiator, and on the probability of losing all auxiliary feedwater before recovery. The uncertainty is expressed as an error factor equal to the ratio of the 95th percentile to the median, or 50% percentile. For SONGS-2 and -3, CE estimated that the error factor on the loss of main feedwater frequency was 3. The recovery of main feedwater in the CE calculation is done only through the use of the condensate pumps and the depressurization of the steam generators. The error factor on the auxiliary feedwater system failure probability is about 15, in the CE calculations.

8.4.2 Staff Evaluation and Conclusions

The staff notes that the logarithm of the variable under consideration (the failure probability for the auxiliary feedwater system) may not be symmetrically distributed, so that the ratio of the 50th percentile to the 5th percentile may be different than the error factor, defined as the ratio of the 95th percentile to the 50th percentile.

The staff concurs with CE in the estimated error factor for the loss of main feedwater. The staff estimates that the error factor for the probability of failure of the auxiliary feedwater system, given loss of offsite power, is about 20, and the error factor for the probability of failure of the auxiliary feedwater system, given offsite power is available, is 43. The staff estimates the probability of the recovery of main feedwater, including implementation of the alternate secondary decay heat removal path, as between 0.07 and 0.25 (5th and 95th percentile values).

8.5 Question 8E: Time for Core Melt

This question asks for the length of time it would take for core melt to initiate.

8.5.1 CE Owners Group Response

CE found that the onset of core melt after a TLOFW, defined as the time at which at 2200°F peak clad temperature was reached, was 60 minutes for a 3410-MWt plant, and 70 minutes for a 3800-MWt plant.

8.5.2 Staff Evaluation and Conclusion

Based on the ANL calculations performed for the staff, the CE calculations appear reasonable.

8.6 Question 8F: SGTR Probability Due to Steam Pressure from a Slumping Core

This question asks for the likelihood of steam generator tube ruptures due to steam pressure from a slumping core.

8.6.1 CE Owners Group Response

This question was not addressed by CE.

8.6.2 Staff Evaluation and Conclusions

The staff has not performed a formal analysis of this issue; however, the staff does not believe the conditional probability of tube rupture to be impacted significantly with or without PORVs.

8.7 Question 8G: Core Melt Consequences

This question asks for a characterization of the consequences of a core melt initiated by total loss of main feedwater, in which steam generators tube ruptures occurred on core slumping.

8.7.1 CE Owners Group Response

The CE Owners Group did not respond to this question.

8.7.2 Staff Evaluation and Conclusion

Previously published PRAs have not considered this type of consequential failure from core melt sequences, and the staff also has not analyzed this case.

The staff judgment is that the benefit of PORVs in reducing risk is likely to be small for such sequences. The staff judgment is based on the following considerations:

(1) Probability of multiple tube failure following core melt is not believed to be high.

(2) There is difficulty in relying on operator action in a short time period following core melt and before multiple tube ruptures to reduce primary pressure via manual opening of PORVs.

8.8 Conclusions

The estimated likelihood of core melt from loss of feedwater events for situations with and without PORVs available is in Section 11 below.

9 SGTR RISK

9.1 Questions 9A and 9B

These questions address the risk from steam generator tube failures.

9.1.1 CE Owners Group Response

CE found that the frequency of core damage as the result of an SGTR in one or both steam generators for SONGS, assuming offsite power is available, is 1.5×10^{-5}/yr (median value), with an error factor of 5. If offsite power is not available, the core damage frequency contribution as the result of an SGTR in one or two steam generators is 1.5×10^{-6}/yr (median value) with an error factor of 11. CE found that PORVs would not appreciably change the frequency of core damage events as a result of SGTRs.

9.1.2 Staff Evaluation and Conclusions

The dominant accident sequences for the SGTR initiator, in the CE analysis, consisted of sequences in which a main steam safety valve (MSSV) stuck open or the high pressure injection system failed. In sequences in which an MSSV stuck open, there is a direct path to atmosphere for the reactor coolant. If the reactor coolant system is not cooled down and depressurized to atmospheric pressure before the refueling water storage tank is emptied, core uncovery will result. However, the staff estimates that there is considerable time before the refueling water storage tank is depleted--about 35 hours for the case of a single tube rupture. During that time it may be possible to cool and depressurize the reactor coolant system to atmospheric conditions, or to find a means for refilling the refueling water storage tank with borated water. Accordingly, the assumption that a stuck-open MSSV after an SGTR leads to core melt is conservative.

The sequences in which failure of the high pressure injection system occurs after an SGTR may also have been treated conservatively. It is possible that the reactor coolant system could be cooled and depressurized to the point where the pressure differential across the ruptured steam generator tube was sufficiently small that makeup could be supplied by the charging pumps, or, as suggested in the CE submittal (CEN-239, Supplement 1, p. 9-1), the primary pressure could be reduced to a level at which the safety injection tanks could prevent or mitigate core uncovery and prevent core damage.

Using the U.S. experience on SGTRs, CE estimated the median frequency of a single tube rupture as 9.7×10^{-3}/yr, and estimated the error factor as 2.6. These appear to be reasonable estimates. The staff notes that the maximum likelihood estimate for the frequency is 4 every 361 years, or 0.011/yr.

CE used an analytical model to determine the frequency of multiple steam generator tube ruptures. The assumption is made in the CE analysis that there is no tube degradation beyond the degradation that existed at the last inspection. Of the four SGTRs that have occurred in U.S. plants, two (one at Ginna and the other at Prairie Island Unit 1 on October 2, 1979) were caused by foreign objects; one was likely caused by changes in water chemistry (Point Beach Unit 1 on February 26, 1975); and one (at Surry Unit 2 on September 15, 1976) was a result of stress corrosion cracking. In all of these events, degradation of the tubes after the last inspection was a factor, and it would not be prudent to employ a model intended to predict the frequency of multiple tube ruptures that did not take this degradation into account. Some other aspects of the model--in particular the distribution used for the burst pressure of an undefected tube, and the dependance of the burst pressure on the percent of wall thickness remaining--are judged to be adequate approximations. Another aspect of the model that appears somewhat arbitrary is the probability distribution for the degree of degradation of a tube. However, the sensitivity of the results for the frequency of multiple tube ruptures to the distribution assumed is not known.

The CE model yields, for the frequency of two tube ruptures in a single steam generator, a value of 6×10^{-3}/yr. An equally plausible value would be about 2×10^{-3}/yr, corresponding to a 50% confidence limit for an event that has not occurred in 361 reactor years. The CE result is conservative with respect to this value. The CE model predicts a probability of 6×10^{-5}/yr for six simultaneous steam generator tube ruptures in one steam generator and lower probabilities for larger numbers of ruptured tubes. The probability decreases with an increase in the number of tubes ruptured (at least, when the number of ruptured tubes exceeds four). Analyses by the staff have assumed, as a conservative upper bound estimate, that the frequency of 10 or more tubes rupturing simultaneously is 2×10^{-4}/reactor-year. With this conservative upper bound frequency for multiple steam generator tube ruptures, multiple tube ruptures do not lead to high estimates of public risk.

In the CE analysis, the risk from SGTRs is dominated by the risk from single tube ruptures, because the sequences considered for multiple tube ruptures are the same as those for single tube ruptures, and the frequencies of multiple tube ruptures are smaller. Staff analyses have obtained a relatively higher contribution from multiple steam generator tube ruptures, but the core melt frequency as a result of the SGTR initiator was 4×10^{-6}/yr, as opposed to the CE estimate of 1.7×10^{-5}/yr.

9.2 Question 9C: Likelihood of Steamlines Filling with Water

This question asks about the likelihood of steamlines filling with liquid water and any consequential failures.

9.2.1 CE Owners Group Response

CE obtained a value of 2.5×10^{-4}/yr (median value) for sequences leading to steam generator overfill after a steam generator tube rupture.

9.2.2 Staff Evaluation and Conclusion

Because there has already been a steam generator event in which a steam generator has overfilled (Ginna event) in some 360 years of PWR experience, this estimate is an order of magnitude low when compared to historical experience. The only consequences of overfilling steam generator considered by CE were the unnecessary challenges to the ADVS and relief valves. Informal communication with CE has indicated that the conditional failure of the steamlines, given that they are filled with water, is small. The staff concurs with this judgment.

9.3 Question 9D: Uncertainties

This question asks for a discussion of uncertainties.

9.3.1 CE Owners Group Response

The CE owners group propagated uncertainties on the individual failure rates to obtain the error factors mentioned in Section 9.1.1.

9.3.2 Staff Evaluation and Conclusions

In general, the CE owners group approach to the treatment of uncertainty is reasonable. The staff notes, however, that the human errors of failing to throttle the high pressure injection system and failing to initiate blowdown were assumed independent, and no sensitivity analysis was performed on the effects of coupling these errors.

Coupling these errors would increase the probability of overfilling the steamlines. In addition, no sensitivity analysis was performed on the assumptions that an SGTR followed by failure of the high pressure injection system leads to core melt, or the assumption that an SGTR followed by a stuck-open MSSV on the affected generator leads to core melt. These omissions in the uncertainty analysis do not affect the conclusion that the addition of PORVs makes no appreciable change in the frequency of core melt as a result of SGTR.

9.4 Conclusions

The staff agrees with the CE owners group that the addition of PORVs would not result in any appreciable change in overall risk if one considers only SGTR events.

10 QUESTION 10: CORE MELT FREQUENCY AS A RESULT OF PORV-INITIATED LOCAs

This question asks for the core melt frequency as a result of PORV-initiated LOCAs and for a characterization of the consequences.

10.1 CE Owners Group Response

In CEN-239 revision 1, CE stated that the core melt frequency from a PORV-initiated LOCA was about 7×10^{-8}/yr (median value) if the plant is operated with the PORV block valves closed, and the error factor on this frequency is 10. If the plant is operated with the PORV block valves open, CE estimates the frequency of PORV-initiated LOCAs to be about 4.1×10^{-6}/yr.

10.2 Staff Evaluation

The staff concurs with the CE assessment of a very small core melt frequency as a result of PORV-initiated LOCAs if the plant is operated with the PORV block valves closed. However, closer analysis is required for the case in which the PORV block valves are open.

A sequence of possible importance is one initiated by loss of offsite power, followed by a PORV lifting and sticking open, followed by failure of both diesel generators. The importance of the sequence depends on the specific design of the PORV system. The staff is considering here the case in which the PORV block valves are open. In the PORV system design considered, in Supplement 1 of CEN-239, the block valves are powered by alternating current, with one diesel generator assigned to each block valve. Moreover, consider a typical CE PORV system in which the pressure at which the PORV opens is the same as the high pressure reactor trip setpoint. Then according to information received informally from CE, the PORV will lift on a loss of offsite power transient, because of the unavailability of turbine bypass to the condenser. Consider then the following sequence:

Event	Probability
Loss of offsite power	0.1/yr
PORV lifts	1
Failure of both diesel generators	2×10^{-3}
PORV sticks open	2×10^{-2}
Power not restored in 30 minutes	0.7

This sequence has a frequency of 3×10^{-6}/yr, and has been conventionally assumed to lead to core melt because the high pressure injection system is without power and there is no power to operate the block valves. The loss of offsite power frequency is a generic value consistent with that in the station blackout analysis report (NUREG/CR-3226), and the failure of both diesel generators is consistent both with this report and the Oak Ridge National Laboratory accident sequence precursor study, NUREG/CR-2498. However, the frequency of this sequence involving a transient-induced PORV LOCA on loss of offsite power can be reduced by increasing the opening setpoint pressure of the PORV. Moreover, it would be possible to power the block valves by direct current. The frequency of this sequence would be reduced by at least a factor of 10, with proper design.

The staff believes that, with a properly designed PORV system and proper operator training, the frequencies of core melt sequences as a result of PORV-initiated LOCAs may be made small, even with the plant operated with the PORV block valves open. Suppose that the frequency of transients involving the lifting of PORVs is 0.28/yr, the probability that a PORV fails to close is 2×10^{-2}, and the probability of operator error in closing the block valve is also 2×10^{-2}. The frequency of transients lifting PORVs is estimated in CEN-145, and the staff concurs with that estimate of 0.28/yr. Then the frequency of small break LOCAs as a result of stuck-open PORVs would be about 2×10^{-4}/yr. For a high pressure injection system (HPIS) failure probability of 5×10^{-4}, one obtains 1×10^{-7}/yr for the frequency of core melt as a result of transient-induced PORV LOCAs for sequences in which power is available to the block valves.

In addition to PORV openings on transients, one must also consider PORV openings caused by maintenance errors. There have been two maintenance errors causing lifting of PORVs in 45 reactor-years of CE experience. (These events occurred at Palisades on September 8, 1971, and at Calvert Cliffs Unit 2 on February 3, 1983.) In each of these events, maintenance errors resulted in placing two reactor protection system channels in a tripped state. This generated a high pressure reactor trip signal, and, because in CE plants, the PORV opening signal comes from the same bistable actuator that generates the reactor trip signal, the PORV also opened. Moreover, the PORV stayed open because the high pressure reactor trip signal continued to be generated. These incidents were terminated by the control room operator closing the block valves. The staff estimates the mean frequency of occurrence of PORV openings from technician errors as 2 every 45 years or 0.04/yr. Combined with a HPIS mean failure probability of 5×10^{-4} (slightly conservative with respect to the median failure probability of 1.5×10^{-4} and the error factor of 4 in CEN-239) and a probability of an operator error of failing to close the block valve of 2×10^{-2}, one obtains 4×10^{-7}/yr for the frequency of core melts as a result of operator-induced PORV LOCAs. The staff notes that CEN-145, submitted in response to TMI Action item II.K.3.2, incorrectly included the contribution to the PORV-initiated LOCA frequency from technician-induced errors. A spurious PORV-initiated LOCA frequency of 5.6×10^{-3}/yr was given (while 0.04/yr is consistent with operating experience), and the fact that the valve may stay open because of the continued presence of the opening signal was not taken into account. The staff estimate of the frequency of PORV-initiated LOCAs followed by failure of HPIS is quite small, provided the PORV block valves are powered by direct current. If CE believes this contribution is greater, this contribution could be reduced by changing the PORV opening logic or installing circuitry for automatic closure of the block valve.

Section 5.2 above shows that an SBLOCA of 0.02 ft^2 (approximately the same size as the PORV area) followed by failure of the HPIS does not lead to core melt if the primary system is aggressively cooled. Thus the assumption that a PORV-initiated LOCA followed by failure of HPIS leads to core melt is likely conservative.

The consequences of a core melt induced by a PORV-initiated LOCA would most probably be those of a core melt in which the containment fails by basemat melt-through, and hence be less serious. For the case of a PORV-initiated LOCA combined with station blackout, discussed earlier, the containment could fail from overpressure if power is not restored for 8 hours. Morever, there is a small probability (about 3%) of the containment failing from a hydrogen burn at the time alternating current is restored, if ac power is restored after core melt. Finally, there is a possibility of containment isolation failure. For these cases, the consequences could be more severe.

10.3 Conclusion

Based on consideration of a reliably designed automatic PORV system, the staff believes that in the loss of heat sink sequences and ATWS sequences, the frequency of core melt caused by an unisolated stuck-open PORV is small compared to the decrease in core melt frequency that would result from adding PORVs.

11 QUESTION 11: NET SAFETY GAINS

This question addresses the net gain or loss in safety that would result from the installation of PORVs.

11.1 CE Owners Group Response

CE noted that the installation of PORVs would not significantly increase or decrease the frequency of core melt due to the SGTR accident initiator, but that loss of heat sink sequences and PORV-initiated LOCA sequences might contribute significantly to the change in safety on the addition of PORVs. No other potential benefits were considered. Two cases were considered: the case of automatic PORVs, in which the PORVs are continuously aligned to the reactor primary system with block valves open, and the case in which the PORVs are normally blocked off, and manually operated. Table 11 gives the median change in core melt frequency, if PORVs were added, as given in CEN-239, revision 1:

Table 11 Median change in annual core melt frequency

Plant	Manual PORVs	Auto PORVs
SONGS-2 and -3	1×10^{-7} decrease	1×10^{-6} increase
Waterford	9×10^{-7} increase	1×10^{-6} decrease

Through discussions between CE and the staff, it was discovered that the treatment of dependent failures was not complete. CE revised its results for SONGS, and communicated them to the staff by phone. These difficulties have been resolved in the revision 1 to Supplement 1 of CEN-239.

11.2 Staff Evaluation

11.2.1 Analysis Scope

The CE owners group response was limited in several ways:

(1) No external events, fires, or internal floods were considered.

(2) The benefit of PORVs in limiting challenges to the pressurizer relief valves was not quantified.

(3) The benefit of PORVs for the mitigation of ATWS events was not quantified.

(4) The benefits of PORVs in depressurizing the primary system during a core melt were not considered.

The calculations of the staff's consultants, Sandia National Laboratory NUREG/CR-3421, were similarly limited in scope. The staff performed its own calculations; these calculations included the effects of PORVs in the mitigation of ATWS events, but otherwise had the same limitations as the CE and Sandia calculations.

11.2.2 PORV System Designs Considered

The CE owners group primarily considered a manual PORV design in which the PORV block valves are normally closed. Each PORV block valve is powered by a diesel generator (on loss of offsite power) and, in the PORV system considered in CEN-239, it is not possible to power a PORV block valve from the other diesel generator. Therefore, on loss of offsite power, failure of either diesel generator results in failure of feed and bleed if the PORV block valves are closed, but feed and bleed success is still possible if the PORV block valves are normally open. The CE owners group originally considered the effects of an automatic PORV (one in which the block valves are normally open, and the PORV opening setpoint is below the relief valve setpoint) on PORV-initiated LOCA sequences, but did not take into account the improvement of such a design for feed and bleed. The new CE results communicated to the staff by telephone, accounted for the improvements in feed and bleed of an automatic PORV. These new results have been documented in revision 1 to supplement 1 of CEN-239.

The PORV system assumed by Sandia National Laboratory was one in which the PORV block valves were normally closed but either diesel generator could power either block valve. This is a substantially more reliable system (for feed and bleed) than the manual PORV system evaluated by CE.

The feed and bleed system assumed by Sandia has a high probability of success on loss of offsite power and failure of one diesel generator.

The PORV system design considered by the staff was one in which the PORV block valves were normally open, so that the PORVs could afford some pressure relief on ATWS sequences. Moreover, it is desirable to minimize the possibility of common mode failure between the reactor trip system and the PORV opening system. At present in CE plants, the signal to open the PORV comes from the same bistable comparator that actuates the high pressurizer reactor trip. It would be desirable to actuate the PORV opening system from a different bistable comparator. This would also provide the opportunity to change the opening pressure setpoint of the PORV to some optimum point that limits unnecessary PORV openings while still providing protection against unnecessary relief valve liftings.

The PORV design assumed by the staff, like that assumed by Sandia, is one that gives a high probability of feed and bleed success on loss of offsite power with failure of one diesel generator. To limit the frequency of PORV-initiated LOCAs on station blackout, the PORV block valves can be powered by direct current.

11.2.3 Calculational Assumptions

A comparison of the assumptions made in the CE, Sandia, and staff analyses is given in Table 12.

11.2.4 Discussion of Analysis Results

The results obtained by CE for the loss of heat sink sequences and the PORV-initiated LOCA sequences for SONGS are given in Table 13. Note that, with the automatic PORV design, the loss of heat sink sequences show a reduction in core melt frequency of 2×10^{-6}/yr. The results quoted are from revision 1 to CEN-239, Supplement 1.

The results obtained by Sandia for the loss of heat sink sequences are given in Table 14. Because Sandia considered only a manual PORV with block valves closed, the PORV-initiated LOCA frequency is negligible.

Table 12 Comparison of assumptions in the CE, Sandia, and staff analyses

Parameter	Assumption		
	CE	SNL	Staff
Type of PORV considered	Manual and automatic	Manual (with diesel generator cross-overs)	Automatic
Credit for condensate system	Yes	No	Yes
Probability of failure of condensate system, given loss of main feedwater not due to loss of offsite power, excluding human error probability of failing to align properly	0.01	---	0.10
Probability of failing to align condensate system properly	0.05	---	0.05
Mean, median, or point value of frequencies based on median values of basic probabilities	Median	Point	Mean
Use of beta factor for treating common-mode pump failures	No	No	Yes
Probability of not restoring offsite power in 50 minutes	0.23	0.23	0.5
Loss of offsite power frequency	0.04/yr	0.09/yr	0.12/yr
Human error probability for failing to initiate feed and bleed	0.025	0.003	0.025
ATWS sequence considered quantitatively	No	No	Yes

The results obtained by the staff for the non-ATWS sequences are given in Table 15. Both the CE and Sandia analyses give no benefit (reduction in core melt frequency) from adding PORVs for SGTR events.

The calculation of the reduction in core melt frequency from ATWS sequences by adding PORVs was performed as follows:

Table 13 CE Owner Group Results for Songs

Initiator	Core melt frequency (CEN-239, revision 1 to supplement 1)
Loss of Heat Sink Sequences	
Frequency, core damage, w/o PORV, w/o condensate system	4.6×10^{-6}/yr
Frequency, core damage, w/o PORV, with condensate system	3.1×10^{-6}/yr
Frequency, core damage, manual PORV, w/o condensate	2.8×10^{-6}/yr
Frequency, core damage, auto PORV	1.1×10^{-6}/yr
PORV LOCA Sequences	
Core melt frequency, PORV LOCA, manual design	7.2×10^{-8}/yr
Core melt frequency, PORV LOCA, automatic design	4.1×10^{-6}/yr

Table 14 Sandia results

Initiator	Core melt frequency	
	With PORV	Without PORV
Loss of Main Feedwater	7.2×10^{-8}/yr	2.6×10^{-6}/yr
Loss of Offsite Power	5.5×10^{-6}/yr	7×10^{-6}/yr

The variation of the ATWS peak pressurizer pressure as a function of moderator temperature coefficient (MTC) was available from curves in CEN-263. These curves were for the case of no turbine trip, and without additional pressure relief. From the data in CEN-239, it was possible to estimate the pressure change associated with turbine trip, and with the addition of PORVs, for a particular value of MTC (about 6% mil). These pressure differentials were assumed independent of MTC. It was, therefore, possible to estimate the peak reactor coolant system pressure during an ATWS for the cases of turbine trip and no turbine trip, and for the cases of no additional pressure relief and additional pressure relief. Then the change (from adding PORVs) in the fraction of the operating cycle in which the peak pressure on an ATWS would be above 3200 psi was estimated. Combining this information with estimates of the ATWS frequency with turbine trip and without turbine trip (ATWS rule, SECY-83-293) for cases where the pending ATWS rule is implemented and it is not implemented, it was possible to estimate the change in the frequency of ATWS events in which the peak pressure exceeds 3200 psi.

Table 15 Staff results for non-ATWS sequences

Initiator	Core melt frequency	
	With PORV	Without PORV
Loss of Main Feedwater	1.7×10^{-6}/yr	9×10^{-6}/yr
Loss of Offsite Power	6×10^{-6}/yr	1.4×10^{-5}/yr
PORV LOCA	$\leq 5 \times 10^{-7}$/yr	--
Net decrease in core melt frequency from adding PORVs	1.5×10^{-5}/yr., not including ATWS sequences	
Error factor	36	
Median decrease	1.4×10^{-6}/yr.	
95% upper confidence limit	5×10-/^{5}yr.	

The staff results for ATWS sequences are given in Table 16.

Table 16 Staff results for ATWS sequences

Case	Frequency of ATWS/year adding PORVs	
	3410-MWt plants	3800-MWt plants
ATWS Rule Not Implemented	3.2×10^{-5}/yr	5×10^{-6}/yr
ATWS Rule Implemented	1×10^{-5}/yr	2×10^{-6}/yr (below 3200 psi 95% of the time without additional relief area)

Notes:

[1]The frequency changes in the above table are the changes in the frequency of exceeding 3200 psia in an ATWS event.
[2]The PORVs added are sized for decay heat removal and have a relief area of 0.0228 ft^2 per valve.

It should be noted that the staff results are mean frequencies, and the CE results are median frequencies. The error factor associated with the staff results for non-ATWS sequences is rather large (error factor = 36); part of the reason for this is that (for the most part) the data used were from the final draft of the NREP procedures guide, NUREG/CR-2815. The distribution suggested there for the failure rates was log-uniform, and the minimum (0th percentile) and maximum (100th percentile) bounds were given there. The propagation of uncertainties employed in the staff calculations was by the method of moments and assumed that these 0^{th} and 100^{th} percentile bounds were the 5th and 95th percentile points for a log-normal distribution. The error factors obtained by CE, as given in CEN-239 Supplement 1 for SONGS, were 21 for the loss of heat sink sequences without PORVs and 28 for the loss of heat sink sequences with PORVs.

The beta factors used by the staff for the motor-driven auxiliary feedwater system pumps had an appreciable effect on the results for the loss of main feedwater sequences with offsite power available, but had a rather small effect on the loss of offsite power sequences. The reduction in core melt frequency in the staff calculations, from the non-ATWS sequences, was about equally divided between the loss of main feedwater (not due to loss of offsite power) sequences and the loss of offsite power sequences. The loss of offsite power frequency and the time to restore offsite power are important parameters in the analysis.

The major differences in results between the staff's and CE's analysis (for the automatic PORV case) can likely be accounted for by (1) the different types of estimates (the staff analysis presents mean estimates, not median estimates, as does CE analysis); (2) the use of the beta factor for the mechanical failures of motor-driven auxiliary feedwater system pumps; (3) the data on loss of offsite power and time to restore offsite power used; and (4) the staff's belief that, with proper design and operation, the core melt frequency from PORV-initiated LOCAs may be made negligible. Supporting analysis for this last point is given in Section 10.2. One may note that the NREP procedures guide (NUREG/CR-2815) gives a mean frequency for loss of offsite power for the SONGS-1 site of 0.235/year, while the value given for the regional council is 0.26/year. The value the staff used was 0.12/year, based on an average over the entire U.S., and was thought to be more appropriate. The quantification of reduction in core melt frequency by the addition of PORVs has not considered external events, fires, or floods. The additional diversity of a feed and bleed path would also be useful for such accident initiators. Although the staff analysis was for SONGS only, the results for the non-ATWS sequence are thought to apply to the other plants as well. The ATWS sequences were considered separately for the 3410-MWt and 3800-MWt plants.

11.3 Conclusions

The staff estimates that, from non-ATWS sequences, the reduction in core melt frequency from adding PORVs is about 1.5×10^{-5}/yr, while from ATWS sequences the reduction in frequency ranges from 2×10^{-6}/yr to 3.2×10^{-5}/yr, depending on whether one is considering a 3800-MWt plant with ATWS rule implemented or a 3410-MWt plant with ATWS rule not implemented.

12 QUESTION 12: COST

If the results of the risk analysis (Section 11) yield appreciable gain in safety, what would be the cost of installing PORVs?

12.1 CE Owners Group Response

Although the CE owners have concluded that the installation of PORVs would have a negligible safety benefit, cost estimates were made to determine expected installation costs. Engineering, design, installation, and replacement power costs were considered.

The Southern California Edison (SCE) Company estimated (Baskin, June 22, 1983) the cost to install PORVs at SONGS-2 and -3 to be $4.6 million, excluding replacement power costs. SCE estimated the time required to complete the installation of the PORVs to be 6 weeks or 42 days. Replacement power costs based on $800,000 per day per plant were estimated to be in the range of $2 million to $35 million per plant. The lower estimate is for extending a normally scheduled outage by 2 to 3 days for system testing after all other work in the plant had been completed. The higher replacement power estimate is for a situation in which the PORVs are installed during an outage scheduled specifically for this design change.

For Waterford Unit 3, Louisiana Power & Light (LP&L) estimated (Drummond, June 29, 1983) the cost for installing PORVs to be $2.3 million, excluding replacement power costs. LP&L estimated the time required to install PORVs to be 80 days. Replacement power costs were estimated to be in the range of $3 million to $30 million depending on the duration of additional downtime beyond a normal refueling outage. Replacement power costs for Waterford 3 during 1985 were estimated to be $1,540,000 per day during the summer and $950,000 per day during other periods. Therefore, the minimal replacement power costs for an additional 3-day outage extension would be about $3 million.

12.2 Staff Evaluation

The staff and its consultants performed an independent evaluation of the engineering feasibility, costs, and operational impacts of installing a system for controlled depressurization of the primary system in CE plants without PORVs. The details of the evaluation are provided in NUREG/CR-3421, and only a summary will be provided here. Basically, the study consisted of developing a conceptual depressurization system design that can be retrofitted into an already constructed plant, and then estimating the associated engineering, design, and installation costs.

SONGS-2 was selected as a plant not currently having a PORV depressurization capability to determine the feasibility and costs of implementing such a capability. However, at the same time, installing PORVs in other plants of similar design was examined to determine what aspects of the design could make a significant difference on a plant-specific basis. In addition, two cases were considered that include: (1) installation of PORVs in a new plant during the final stages of its construction, and (2) installation of PORVs in a plant that has been operating for some time.

For the purpose of investigating the engineering feasibility and implementation costs, a conceptual system design was developed for a primary system depressurization capability utilizing PORVs or other types of relief valves that can be retrofitted into SONGS-2. The system design, a schematic of which is shown in Figure 7, consists of two dedicated PORVs and two block valves mounted at the top of the pressurizer, using the nozzles provided for the existing safety relief valves (SRVs), a quench tank (similar to the existing quench tank), and connecting piping. The PORVs or other types of relief valves would be large enough, with relieving capacity well in excess of that required for decay heat removal, to depressurize the system as rapidly as possible to permit an existing HPSI pump to initiate flow injection. Valve capacity and time of opening after a total loss of feedwater event would be consistent with the thermal-hydraulic evaluation reported in ANL/LWR/NRC-83-6 (Komoriya, 1983). In addition to adding PORVs, ANL/LWR/NRC-83-6 also reported a case involving the addition of a new HPSI pump to permit flow injection to be initiated near full system pressure. This case was investigated for the broader objectives of the USI A-45 program on "Shutdown Decay Heat Removal Requirements," in which a feed and bleed mode of decay heat removal will be ranked against other alternative measures for improving decay heat removal system reliability based on value-impact evaluations. The USI A-45 recommendations are expected to be made in November 1984.

The more important system design criteria would include the requirements that (1) the system equipment and piping must be consistent with the existing components with respect to ASME Code Class, Nuclear Safety Class, Quality Group Class, and Seismic Category; (2) the new PORVs would be fully safety grade and environmentally qualified; (3) the system must be capable of operation when offsite power sources are unavailable (i.e., from a single existing diesel generator); and (4) the new system must in no way affect the functions of the existing safety systems.

It was determined that the supply of electrical power from an existing diesel generator to the new PORVs and block valves poses no problems. No major structural changes or additions would be required to accommodate the depressurization system. Structural work would consist mainly of additional pipe supports, platforms, walkways, and railings.

The conceptual design is based on an automatic control scheme. At a certain pressure setpoint, the PORVs would be fully opened automatically to reduce the primary system pressure to a level at which the existing HPSI pump would initiate flow to prevent core uncovery. In the final design phase of the control system, consideration should be given to an all-manual control system because of: (1) simplicity of control and avoidance of spurious actuation, (2) elimination of the need to interface with existing primary pressure and feedwater flow instrumentation channels (thus, no possibility of jeopardizing these channels, and (3) lower implementation costs. However, costs would not be a primary consideration in selecting automatic versus manual control. Full instrumentation for flows, pressures, temperatures, and levels is included in the design, including special instrumentation to sense accidental opening of the valves.

The detailed engineering and design of a primary system depressurization system would be of the type normally performed for nuclear power plant safety systems. Because of the expectation that a system for a particular plant would either be designed and installed during the later stages of overall plant construction, or retrofitted into an operating plant, the engineering and design would have to be organized as a separate project with a dedicated project team.

Before the final design phase, a special analysis of the nature of the depressurization system application will have to be done, including (1) thermal-hydraulic transient analyses to determine the correct relief valve size and

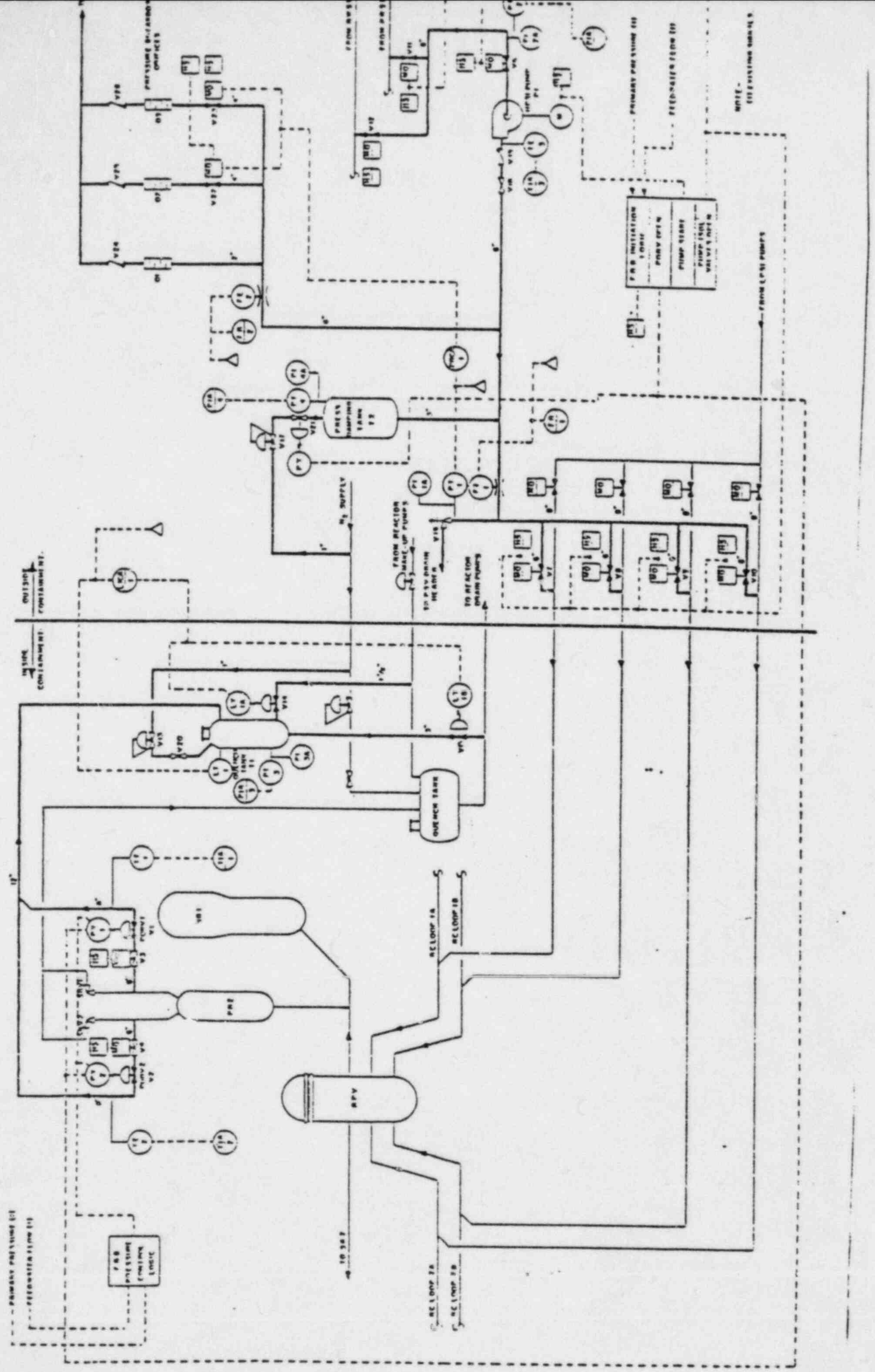

Figure 7 Flow schematic of primary system depressurization system

initiation time, (2) studies to support selection of the best type of relief valve and valve installation for this application, (3) analyses of stresses due to added loads on critical piping, and (4) analyses of actual radiation levels for controlling personnel exposure.

Coordinated schedules for (1) engineering, design and analysis and (2) construction have been developed. The former has a span of 18 months and the latter 12 months. There is a 6-month overlap, resulting in an overall project schedule of 24 months. The schedule is keyed to an annual outage for refueling and scheduled maintenance that is considered to be of 60 days' duration. For an operating plant, the schedule and costs are based on doing as much of the work as possible while the plant is operating to minimize the work to be done during the scheduled outage. This would require very careful planning to complete the installation within the allocated time.

In retrofitting a primary system depressurization capability to a plant that has been in operation for some time, occupational radiation exposure to personnel will be a concern. The problem area is around the pressurizer within containment. For a plant that has been operating for a number of years (about 3 to 6), shutdown radiation levels can be as high as 0.4 R/hr at certain specific locations, such as the pressurizer spray line. Such levels would severely limit the time that personnel could spend in the area during installation. It appears that it would be feasible to install temporary shielding in the area of the pressurizer that would reduce the radiation levels to about 0.15 R/hr. It has been assumed in the cost estimate that an allowance would have to be made so installation personnel, who might receive their maximum permitted whole body dose, would not be in violation of the regulations. The total accumulated dosage for all personnel during installation of the depressurization capability is estimated to be about 400 man-rems.

Although the feasibility and costs of installing a system for primary system depressurization was investigated specifically for SONGS-2, the conceptual design and evaluation developed in NUREG/CR-3421 would have a generic applicability to other plants that do not have a PORV capability. However, an important factor that could be expected to affect the feasibility and cost for a specific plant would be the arrangement of equipment and piping around the pressurizer and the availability of a suitable connection for the installation of PORVs or other types of relief valves.

Cost estimates were made for installing a primary system depressurization capability in (1) a new plant under construction and (2) a plant that had been in operation for some time. The total installation costs for these two cases are $2,495,000 and $4,254,000, respectively. The details of these estimates are presented in Tables 17 and 18. As is shown in Tables 17 and 18, construction costs and costs for supporting services were estimated separately. Construction costs were subdivided into costs for mechanical equipment and piping, structural work, electrical work, and instrumentation and control work. Included under supporting services were project management, engineering design and analysis, quality assurance, construction management, testing and startup, training, and costs related to health physics and radiation exposure control.

Prevailing construction labor rates in the San Diego area were used, and allowances were made for three-shift operation, premium time on weekends, overtime at shift changes for work during the scheduled plant outage, and travel allowances for construction workers. In the case of installation in an operating plant, an allowance was made for the additional hours and other costs associated with burnout of craft labor personnel in high radiation areas and for the general difficulties associated with working in an operating plant.

Present-day costs were used, and escalation applied at 6% per year using the developed schedule. Allowance was made for interest during construction at an annual rate of 12%. An overall contingency allowance of 25% was used.

In the case of an operating plant, replacement power costs incurred by prolonging a scheduled annual outage by the installation of the depressurization system could result in costs that would exceed the total of all other implementation costs in just a few days, considering that replacement energy costs are typically in the range of $500,000 to 1,000,000 per day. In an actual installation, if the work could not be completed in the period of one annual outage, it could be completed during the following year's outage. The necessity for hydrotesting (in accordance with Section XI of the ASME code) at the completion of system installation may extend the outage by 2 to 3 days. This would add

A comparison of the staff's independent cost estimates with those of the CE owners group is shown in Table 19. Besides the PORV installation cost, the staff has also shown a comparison of the installation time and estimated replacement power costs. As is evident from Table 19, for a new plant that has not been placed into operation, the staff installation cost estimate ($2.5 million) is close to the CE owners group cost estimate ($2.3 million). For a plant that had been in operation for some time, the staff installation cost estimate ($4.3 million) is about $2 million higher than the CE owners group results for a plant like SONGS-2. However, because SONGS-2 has less than 1 year of operational time at power, the staff's cost estimate is considered to be conservative. For the estimates of the time required to install the depressuirzation system, the staff's estimate (60 days) falls about midway between the CE owners group results (42 days to 80 days). However, the staff considers that with careful planning, the installation can be completed within a normal refueling and maintenance outage. With respect to the cost estimates for replacement power, the staff estimates fall in the range of zero to $3 million, depending on whether the normal outage has to be extended several days for testing the depressurization system. However, as mentioned above, turbine generator maintenance is usually on the critical path in determining the total outage time, and, if this is the case, testing of the depressurization system would not add to the normal outage time. The CE owners group estimates for replacement power cover the range of $2 million to $35 million, depending on the extra plant downtime attributed to PORV installation, testing, and actuation over the plant lifetime. The staff considers the CE owners group low estimates of $2 million to $3 million for replacement power costs as a result of PORV testing to be reasonable. However, the staff believes that the CE owners group high side estimates ($30 million to $35 million) are unreasonable and have not been adequately justified.

Table 17 Cost estimate for controlled depressurization system for installation in a new plant under construction

Item	Estimate costs ($)
1. Construction	
1.1 Mechanical equipment and piping	665,000
1.2 Structural	35,000
1.3 Electrical	27,000
1.4 Instrumentation and control	236,000
Total construction	963,000
2. Services	
2.1 Project management, planning and scheduling, and cost estimating	52,000
2.2 Engineering, design, and analysis	423,000
2.3 Quality assurance	20,000
2.4 Construction management	40,000
2.5 Test and startup	20,000
2.6 Training	18,000
Total services	573,000
3. Total present estimated costs	1,536,000
4. Escalation	246,000
Sub-total	1,782,000
5. Interest during construction	214,000
Sub-total	1,996,000
6. Contingency	499,000
7. Total estimated costs at completion	2,495,000

Table 18 Cost estimate for controlled depressurization system for installation in an operating plant

Item	Estimated costs ($)
1. Construction	
1.1 Mechanical equipment and piping	1,132,000
1.2 Structural	126,000
1.3 Electrical	117,000
1.4 Instrumentation and control	556,000
Total construction	1,931,000
2. Services	
2.1 Project management, planning and scheduling, and cost estimating	65,000
2.2 Engineering, design, and analysis	425,000
2.3 Quality assurance	24,000
2.4 Construction management	48,000
2.5 Testing and Startup	24,000
2.6 Training	58,000
2.7 Health physics	45,000
Total services	688,000
3. Total present estimated costs	2,619,000
4. Escalation	419,000
Sub-total	3,038,000
5. Interest during construction	365,000
Sub-total	3,403,000
6. Contingency	851,000
7. Total estimated costs at completion	4,254,000

Table 19 Comparison of costs

Analyzing organization	PORV installation costs per plant ($ million)	Time to install PORVs (days)	Replacement power costs per plant to install PORVs ($ million)
NRC staff			
Case 1: Before operation	2.5	60	0
Case 2: After operation	4.3	60	0 to 3
SCE (SONGS-2 and -3)	2.3	42	2 to 35
LP&L (Waterford 3)	2.3	80	3 to 30

12.3 Conclusions

As a result of its independent evaluation of engineering feasibility, costs, and operational impacts, the staff has reached the following conclusions:

(1) For PWR plants lacking primary system PORV capability, addition of a system to permit controlled depressurization would be feasible.

(2) Installation of a depressurization system would have to be very carefully planned and executed, particularly in an operating plant. An overall schedule of 2 years from start of engineering and design to completion of installation and testing is considered feasible. For an operating plant, keying the installation schedule to an annual scheduled outage would be essential so installation could be completed within a normal 60-day outage and any extra plant downtime avoided.

(3) Occupational radiation exposure to personnel for installation in an operating plant will have to be taken into account, but appropriate allowances can be made. Total personnel radiation exposure to complete the installation is estimated to be about 400 man-rem.

(4) Implementation costs for installing a depressurization system range from $2.5 million in a plant that has not operated to $4.3 million in a plant that has operated for some time. Testing of the depressurization system could extend a normal outage by 2 to 3 days and would result in an added replacement power cost of about $3 million.

13 QUESTION 13: SYSTEM 80 STEAM GENERATOR TUBE STRUCTURAL INTEGRITY

This question asks CE to fully describe the CE System 80 steam generator tube structural integrity.

13.1 CE Owners Group Responses

An important consideration in determining whether or not PORVs are needed for emergency decay heat removal is the availability of alternative water sources for the steam generators for decay heat removal purposes. An assumption inherent in this approach is that steam generator integrity will be maintained throughout the life of the plant. One method of ensuring steam generator integrity is periodic inservice inspections and plugging excessively degraded tubes. RG, 1.121 "Bases for Plugging Degraded PWR Steam Generator Tubes," describes the plugging criteria and the methodology for determining plugging limits.

CE evaluated the System 80 steam generator to determine the allowable tube wall degradation. This evaluation shows that 43% tube wall degradation is acceptable at the most limiting tube locations; this value is determined by conservative comparisons to analyses performed on other CE steam generator designs. CE has also provided some tests results that substantiate the validity of the analytical methodology used by CE to determine tube plugging limits.

13.2 Staff Evaluation

It has been demonstrated previously in the ASME Code stress reports for six CE pre-System 80 power plants that tube wall degradation ranging from 31% to 64% can be tolerated and the plant still meet the design-basis criteria and the provisions of RG 1.121. The range is higher yet (50% to 64%) for those units that have not received a "rim-cut" modification to mitigate support plate denting.

The CE System 80 steam generator tubes (see Figure 8) also have been evaluated for most design and pipe break accident criteria. Because most CE steam generators are similar in design concept, an estimate of the permissible tube thinning for the System 80 steam generator units can be made based on work performed on other units and supporting experimental data.

The margin of safety against tube failure under a postulated LOCA concurrent with an SSE has been shown to be consistent with the margin of safety determined by stress limits specified in Subsection NB-3225 of Section III of the ASME Code.

As a result of a postulated LOCA, a steam generator U-tube will experience an inplane frame-type deformation as a result of the rarefaction wave in the primary coolant that propagates away from the break location. This loading--when combined with the SSE loading, LOCA impulse, and differential pressure--causes severe bending stress in the tube at the uppermost horizontal support.

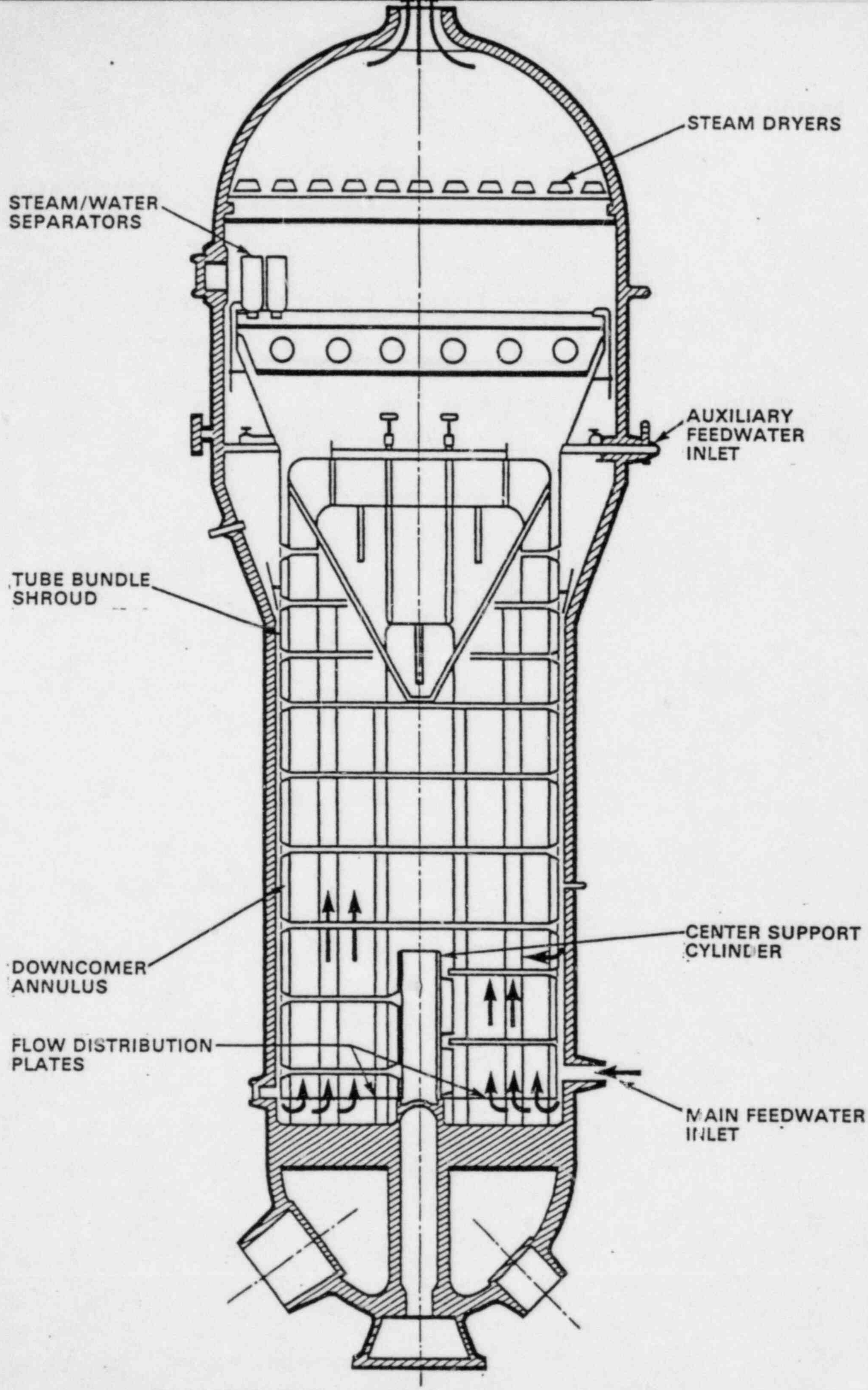

Figure 8 Integrial Economizer Steam Generator Axial Flow

Geometries evaluated thus far sustain maximum tube bending stresses in healthy tubes of between 26.0 ksi and 52.1 ksi for the LOCA-plus-SSE accident.

In addition, it has been determined that tubes having local uniform degradation at the worst possible locations of between 31% and 64% of the nominal tube wall can withstand this accident condition and still meet the criteria in Appendix F of the ASME Code Section III for faulted conditions.

The margin of safety against tube failure under a postulated steamline break concurrent with an SSE has been shown to be consistent with the margin of safety determined by the stress limits specified in Subsection NB-3225 of Section III of the ASME Code.

In the event of a postulated main steamline break (MSLB), the top of the tube bundle is subjected to extremely high velocity, high density crossflow of the secondary coolant. In a U-tube steam generator, this loading--when combined with SSE, MSLB impulse, and internal pressure--causes vertical bundle deflection with interaction among the various tube rows. The resulting tube stress is highest at the top mid-span position. The tube row of maximum stress is design dependent.

Geometries evaluated thus far sustain maximum tube bending stresses of 27.2 ksi or less for the steamline break-plus-SSE accident acting on healthy tubes. In addition, it has been determined that tubes having local uniform degradation at the worst possible locations of 63% or less of the nominal tube wall can withstand this accident condition and still meet the criteria established in Appendix F of the ASME Code Section III for faulted conditions.

The margin of safety against tube failure under a postulated feedwater line break accident concurrent with an SSE has been shown to be consistent with the margin of safety determined by the stress limits specified in Subsection NB-3225 of Section III of the ASME Code.

The economizer divider plate, support cylinder, cold leg flow distribution plate, and feedwater box are subjected to a hypothetical feedwater line break during 100% power operation. The pressure distribution acting on the economizer divider plate during a postulated feedwater line break was determined by applying the peak pressure differences between nodes. Reactive forces acting on the divider plate along the lugs that are attached to the support cylinder were applied to the support cylinder. These forces--along with the pressure differential acting on the cylinder between the hot leg and cold leg--comprised the active forces on the support cylinder. The peak pressure difference of 660 psi was assumed to act uniformly over the feedwater box.

The primary stresses of concern in the divider plate and blowdown assembly are maximum-membrane-plus-bending stress of 34.2 ksi which is less than the allowable of $1.5(0.7\ S_u) = 73.5$ ksi for the SA-515, GR 70 material. The blowdown duct has maximum-membrane-plus-bending stress of 47.4 ksi, and the allowable is 60.9 ksi.

The membrane-plus-bending-stress intensity at the base of the stay cap assembly is 14.5 ksi, which is less than the allowable of $1.5(0.7\ S_u) = 77.3$ ksi for the SA-508, CL 2 material. At the bi-metal wall, the membrane-plus-bending stress intensity is 9.4 ksi, and the allowable is 67.5 ksi for the SA-516, GR 70 material.

The flow distribution plate has maximum-ligament-membrane-plus-bending stress intensity in the perforated regi(n of 49.6 ksi, and in the solid rim, it is 34.8 ksi. The allowable for the SA-240, TY 405 material is 1.5 (0.7 S_u) = 58.7 ksi.

The inner cylinder of the feedwater distribution box has maximum-membrane-plus-bending stress intensity of 38.4 ksi, with the allowable for the SA-515, GR 70 material of 1.38 (0.7 S_u) = 67.6 ksi.

The direct loading of the escaping fluid on the tubes is small (G $\leq$ 1.0 ksi) The danger to the tubes is that if one of the above four structures fails, it would put the adjacent tubes in jeopardy. However, as noted above, these structures are very conservatively designed; therefore, they will have no impact on thinned tubes.

13.3 Conclusions

System 80 plants are comparable to plants that have been calculated to have an allowable tube wall thinning of from 50% to 64%. System 80 allowable tube wall thinning limit is conservatively estimated to be 43%.

Units that have had their upper support plates detached from the shell (to mitigate denting effects) have somewhat lower permissible tube thinning values in the upper tube bundle region. (There is no effect near the tubesheet.) To date, CE plants have not experienced denting and tube attack in the same region of the steam generator.

Experimental results, from several sources, demonstrate that for degradation other than uniform thinning, additional conservatism is introduced by reinforcement supplied by the material surrounding the degradation. Further conservatism is introduced by the fact that most of the tests show a benefit from greater than minimum ultimate strengths.

Simulated full-scale LOCA testing has verified the accuracy and conservatism of CE's current methodology and analytical computer codes in determining steam generator tube loading resulting from a hypothetical loss of primary coolant accident (LOCA). This event is controlling for tubing in CE steam generators.

Analysis results show that the economizer divider plate, support cylinder, cold leg flow distribution plate, and feedwater box are adequately designed to withstand a hypothetical feedwater line break. Thus, the tubes in the economizer region will not be damaged, because, being lightly loaded hydraulically, only failure of an adjacent structures would harm the tubes.

On the basis of its review of the CE analysis of System 80 steam generators, the staff concludes that adequate margins of safety exist against tube failures under both accident and normal operating conditions.

14 QUESTION 14: TUBE VIBRATIONS

This question asks CE to fully describe tube vibrations in the economizer region of system 80 steam generators.

14.1 CE Owners Group Responses

Recent occurrences of excessive flow-induced vibration in the economizer region of some Westinghouse steam generators of similar design prompted the NRC staff to assess the susceptibility of the System 80 steam generators design to similar damage mechanisms. CE has conducted experimental investigations of flow-induced vibration in the economizer region of the System 80 steam generator. Scoping tests were first conducted with a 30° sector of a full-scale model, and no tube vibrations of consequence were measured. More recent test results obtained from an expanded test program confirm that the tubes experience no potentially harmful vibrational motion.

14.2 Staff Evalution

The System 80 steam generator design incorporates an integral axial flow economizer on the cold leg side of the tube bundle as shown in Figure 8. The economizer region is formed by a divider plate located in the tube lane and attached to the support cylinder and shell, extending to a height of 100 inches above the tubesheet. There are two locations in this region where water enters the tube bundle, as shown in Figure 9. At the tubesheet, feedwater enters from the feedwater distributor below the flow distribution baffle and flows upward through the bundle. At the top of the economizer, auxiliary feedwater mixed with the cold leg recirculated water enters from the downcomer through an opening in the shroud.

The region of the steam generator that was modelled includes both the feedwater and cold leg downcomer inlets to the tube bundle. Tubes, tube support spacing, and shell side inlet openings are the same as for the System 80 steam generator. The model is rectangular in shape and constructed from structural steel with plexiglas sides to permit visual studies. It consists of 144 tubes, each 175 inches long, which are arranged in a 7-line pattern, as shown in Figure 10. The tube array is representative of a bundle with a depth of 20 rows of tubes from the periphery.

Selected tubes near the flow inlets are instrumented with semi-conductor strain gauges and bi-directional accelerometers. Penetrations through the plexiglas side are provided at eight elevations downstream of the two inlet openings for insertion of a Pitot probe that can be moved horizontally for measuring velocities at positions across a section.

The test model is installed in a loop that consists of a holding tank, a centrifugal pump, flow control valves, flow meters, and orifice plates.

Inlet flow may be admitted to both economizer and downcomer inlet regions. System control valves are manipulated to achieve predetermined axial and radial mass fluxes through the tube bundle.

Hydraulic testing was performed at room temperature with nominal flow rates equivalent to 100% power and for downcomer flows up to 200% nominal. Modeling similitude was based on equality of dynamic pressure. For the 100% case, the specified System 80 feedwater flow was used.

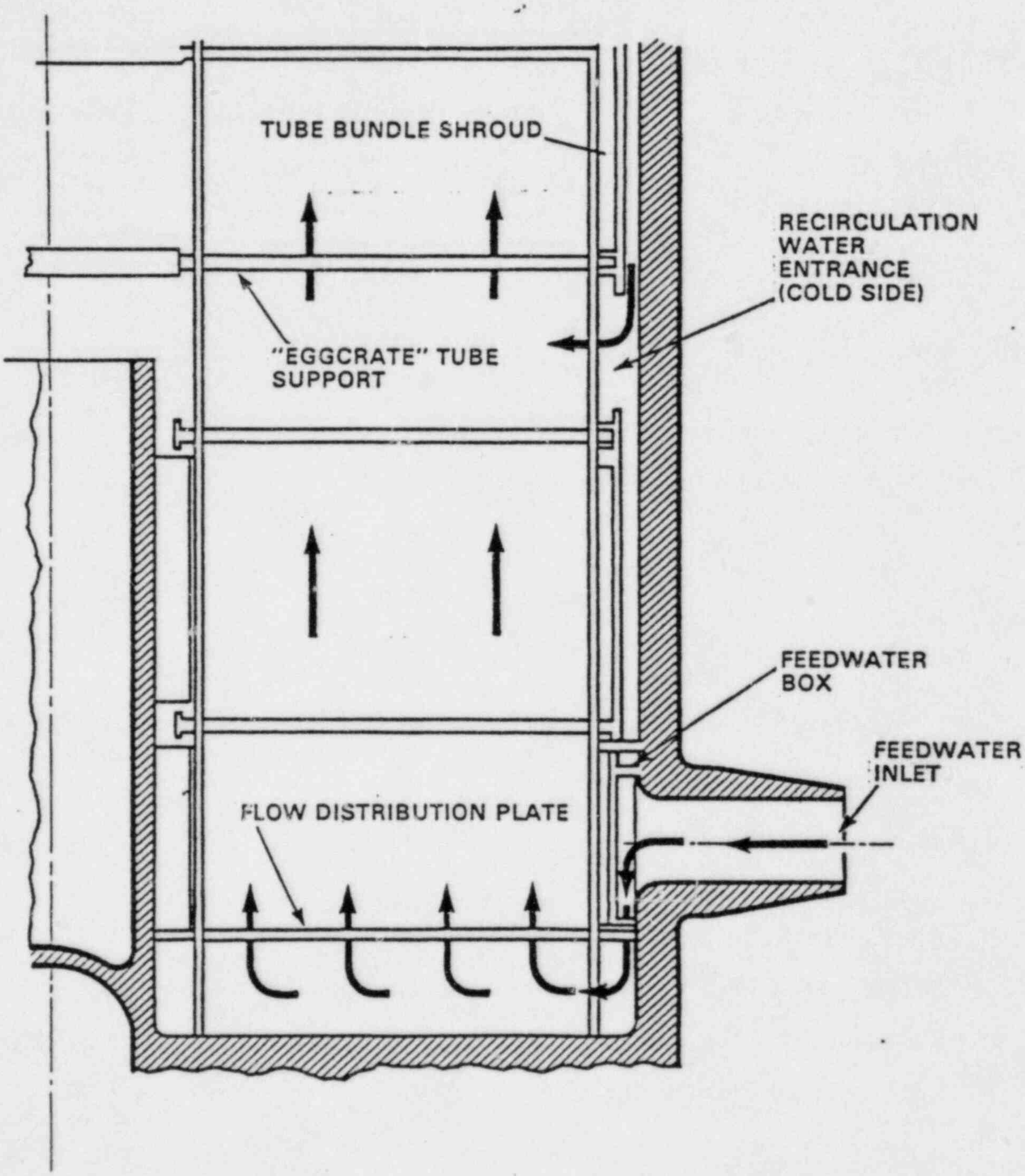

Figure 9 Axial Flow Economizer

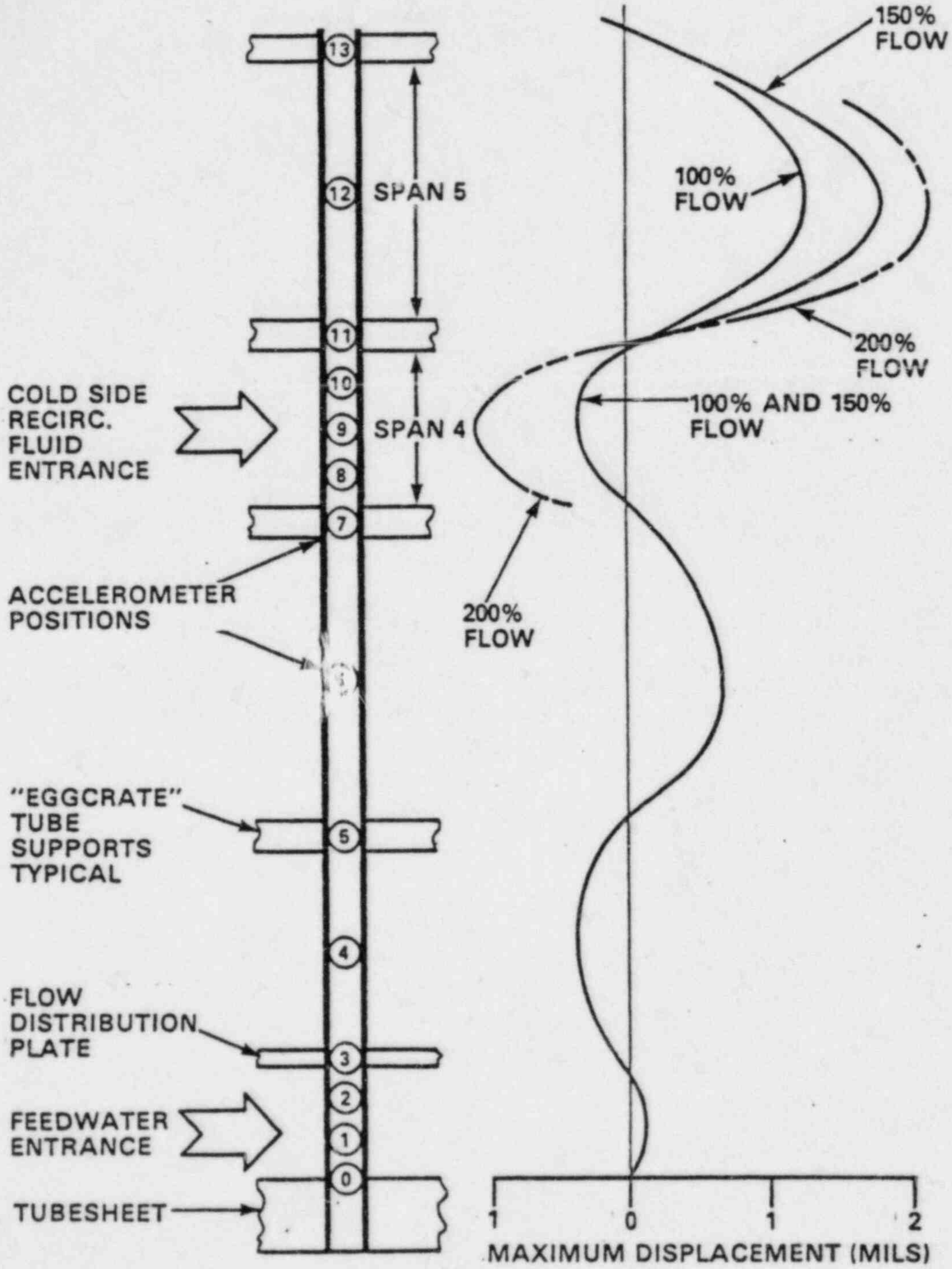

Figure 10 Tube Vibration Amplitude Profile

Velocity distributions of the shell side fluid downstream of the two inlet openings were established from measurements made at eight vertical and four horizontal intersecting locations. A two-dimensional "wedge" Pitot probe was used for measuring the direction and magnitude of flow velocity at each grid point. Measured deflections and vibration amplitude profiles have been provided (Figure 10). Based on the review of the data, the following observations may be made:

(1) The tube motion was elliptical with the major axis in the transverse direction.

(2) The largest observed vibration amplitudes occured in the span above the cold side downcomer fluid entrance region.

(3) The level of vibration in the tube span subjected to cold side downcomer fluid (span 4) was relatively constant at 0.4 mil up to approximately 150% flow. The bending stress is less than 1 ksi for 100% flow.

(4) No vortex shedding induced vibration was observed for two reasons: (a) the fluid approaching the bundle was too turbulent, and (b) the triangular pitch tube array is so tightly packed that vortices cannot be sustained.

(5) When the velocity profiles were examined, it was concluded that there is at least 50% margin to instability at 100% power.

(6) Vibration of tubes in the feedwater entrance region of the tube bundle are extremely small as was predicted. All of CE's operating steam generators have higher levels of vibration at the bundle entrance regions than will exist at the System 80 feedwater entrance region as a result of the greater velocity of the recirculating fluids.

14.3 Conclusion

A full-scale test of the System 80 steam generator economizer region was performed to investigate the vibrational response of tubes when subjected to cross flow resulting from water issuing from inlet openings. Both the feedwater inlet at the tubesheet and the recirculated water inlet at the top of the economizer region were included in the model. Test runs were made for nominal prototypic flow conditions and for recirculated water flow up to 200% nominal. From results of the tests, the staff concludes that tubes in the System 80 economizer region will experience no detrimental vibrational motion during normal operation.

APPENDIX C

ACRONYMS

ACRS	Advisory Committee on Reactor Safeguards
ADHR	alternate decay heat removal
ADV	atmospheric dump value
AEB	Accident Evaluation Branch, NRC
AFW(S)	auxiliary feedwater (system)
ALARA	As low as reasonably achievable
ANL	Argonne National Laboratory
ANO	Arkansas Nuclear One (Station)
APS	auxiliary pressurizer spray
ASB	Auxiliary Systems Branch, NRC
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
B&R	Brown and Root
BTP	Branch Technical Position
B&W	Babcock & Wilcox
CE	Combustion Engineering
CEB	Chemical Engineering Branch, NRC
CFR	Code of Federal Regulations
CST	condensate storage tank
CVCS	chemical volume and control system
ECC(S)	emergency core cooling (system)
EFWS	emergency feedwater system
EPG	emergency procedure guideline
EQB	Equipment Qualification Branch, NRC
FSAR	Final Safety Analysis Report
HPI	high pressure injection
HPSI	high pressure safety injection
HPSIP	high pressure safety injection pump
LCO	limiting condition for operation
LOCA	loss-of-coolant accident
LOFT	loss-of-fluid test
LOFW	loss of feedwater
LOOP	loss of offsite power
LP&L	Louisiana Power & Light
LPSIP	low-pressure safety injection pump
LTOPS	low temperature overpressure protection system

MEB	Mechanical Engineering Branch, NRC
MFW	main feedwater
MFLB	main feedwater line break
MOV	motor-operated valve
MSGTR	Multiple steam generator tube rupture
MSIV	main steam isolation valve
MSLB	main steamline break
MSSV	main steam safety valve
MTC	moderator temperature coefficient
MWt	megawatts thermal
NPS	normal pressurizer spray
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation, NRC
NTOL	Near Term operating license
ORE	occupational radiological exposure
PORV	power operated relief valve
PRA	probabilistic risk assessment
PSRB	Procedure and Systems Review Branch, NRC
PTS	pressurized thermal shock
PWR	pressurized water reactor
RCP	reactor coolant pump
RCS	reactor cooling system
RES	Office of Regulatory Research, NRC
RRAB	Reliability and Risk Assessment Branch, NRC
RSB	Reactor Systems Branch, NRC
RVUH	reactor vessel upper head
RWST	refueling water storage tank
SBCS	steam bypass control system
SBLOCA	small-break loss-of-coolant accident
SCE	Southern California Edison
SDCS	shutdown cooling system
SEPB	Systematic Evaluation Program Branch, NRC
SG	steam generator
SGTR	steam generator tube rupture
SIAS	safety injection actuation signal
SIT	safety injection tank
SNR	
SONGS	San Onofre Nuclear Generation Station
SRV	safety/relief valve
TLOFW	total loss of feedwater
TMI-2	Three Mile Island Nuclear Power Station, Unit 2
V/I	value/impact

APPENDIX D

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This report documents the NRC staff evaluation of the need for providing a rapid primary system depressurization capability, in particular by using a power-operated relief valve(s) (PORVs), in the current 3410-MWt and 3800-MWt classes of plants designed by Combustion Engineering (CE).

The staff reviewed the responses of licensees, applicants, and vendors to staff questions, supplemented by independent analyses by the staff and its contractors. The staff review led to the conclusion that, on the basis of risk reduction and cost/benefit considerations, no overwhelming benefit would result from requiring the installation of PORVs in CE plants that currently do not have them. However, when other unquantifiable considerations regarding the potential benefits of a PORV are factored into the evaluation, it appears that more substantial benefits could be realized. Given the more comprehensive studies currently under way to resolve the generic unresolved safety issue, USI A-45, Decay Heat Removal Reliability, the staff concludes that the decision regarding PORVs for these CE plants should be deferred and incorporated into the technical resolution of USI A-45. Resolution of USI A-45 will also include the effects of residual risks due to fires, floods, earthquakes, and sabotage.

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